Abstract

The storage potential of selected sites within the Bahaiwan Basin was evaluated, the storage capacity estimated and the selection criteria considered for the COACH project. This paper examines the two methods used during the project for calculation of the storage capacity in the Shengli oilfield complex within the Bahaiwan Basin. Both methodologies were used to quantify the potential CO\textsubscript{2} storage capacity of the depleted oil hydrocarbon reservoirs of the Shengli oilfield complex. They can both be considered as "simple" equation models which try to capture an "approximation" of a possible storage capacity. Nevertheless, between these models several differences exist. The CSLF methodology works with replacement of oil, gas or formation water, but does not incorporate dissolution of CO\textsubscript{2} in formation water. The EOR methodology of CUPB developed from methodology of Tanaka et al. on the other hand includes dissolution of CO\textsubscript{2} into the formation water, but does not consider the time period needed for the dissolution.

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Keywords: Type your keywords here, separated by semicolons; China; Bahaiwan (Bohai) Basin; CCS; CSLF methodology; EOR methodology; CUPB

1. Introduction

The challenge of climate change demands reduction in global carbon dioxide (CO\textsubscript{2}) emission. Carbon capture and storage (CCS) technology can be used to trap and store carbon dioxide gas emitted by coal-burning plants and this can potentially reduce the world’s total CO\textsubscript{2} emission by about one quarter by 2050 [1, 2, 3]. Experience from the storage sites of Sleipner in the Norwegian North Sea, In Salah in Algeria, Nagaoka in Japan, Frio in USA and other sites shows that geological structures can safely accommodate CO\textsubscript{2} produced and captured from large CO\textsubscript{2} point sources.
sources. CCS is one of the solutions to reduce carbon emissions and serves as a bridging technology towards a carbon free energy market.

China has large coal reserves [4], and is not about to give up on this reliable source of fossil fuel. Hence a large production of CO2 can be expected to continue for many years. China has also favourable geology which could facilitate permanent storage in onshore areas within deep saline formations [5, 6]. In an extensive collaborative research effort between Chinese and European scientists, the COACH project (Cooperation Action within CCS China-EU) was successful in building the expertise, evaluating the capture technologies and mapping transportation routes for CO2 and it produced two scenarios for geological storage of CO2 in China. COACH was a project funded by the European Commission under the China-EU Memorandum of Understanding (2006) on Near Zero Emissions from Coal (NZEC). The overall objective of this project was to evaluate the feasibility of the deployment of CCS in China. The project ran from November 2006 to October 2009. COACH had four technical working groups dealing with knowledge sharing and capacity building, capture technologies, geological storage and large scale use of CCS and recommendations and guidelines for implementation. Twenty partners consisting of eight Chinese and twelve European partners evaluated the feasibility of establishing CCS in China (COACH 2009).

2. Methodology

A regional level assessment of selected potential storage sites for CO2 in the Bahaiwan Basin (Bohai Basin) was carried out for the COACH project. The storage capacity was estimated in each case using a simplified version of the Carbon Sequestration Leadership Forum (CSLF) methodology [8, 9, 10]. The storage reservoir properties, sealing formation properties, reservoir injectivity and other relevant parameters were also considered. For all sites considered, publicly available data were used. PetroChina also provided data for the Dagang oilfield province and the China University of Mining and Technology carried out experiments on coal samples to improve the accuracy of the storage assessment in unmineable coal seams in the Kailuan mining area.

The aim of CO2 storage is the permanent removal of CO2 from the atmosphere. The European Union has supported current research on CO2 capture and storage methods for more than a decade, with emphasis on capture techniques, transport and geological storage. The results of the research on geological storage are summarised in a comprehensive manual by Chadwick et al. [11]. Internationally recognised standards for capacity assessments were established by the Carbon Sequestration Leadership Forum (CSLF) in 2004–2005 [8] and a task force on capacity estimation standards has been active since presenting comprehensive definitions, concepts and methods [9, 10]. These capacity standards were reviewed for the COACH project by Poulsen et al. [12] and were used for the work on permanent CO2 storage estimates in China [6, 13, 14, 15].

Potential CO2 storage sites in the Bahaiwan Basin (East China) (Fig. 1) were investigated [6, 12, 15]. Some potential oilfields, saline aquifers and unmineable coal beds have been assessed. The CSLF-based methodology [8, 9, 10] was applied to evaluate storage potential. Within the investigated area, COACH localised and described a pilot scheme that could prove the concept of Carbon Capture and Storage (CCS) and CO2-Enhanced Oil Recovery (CO2-EOR) in this region of China [6, 15], which fulfil the basic storage site selection criteria:

1. Sufficient depth of reservoir to ensure that CO2 reaches its highly dense phase but not so deep that permeability and porosity is too low.
2. Integrity of seal to hinder CO2 escape.
3. Sufficient CO2 storage capacity.
4. Effective petrophysical reservoir properties to ensure CO2 injectivity such that the site is economically viable and that sufficient CO2 can be stored.

3. Comparison of methods

Various methods are available for calculation of CO2 storage capacity in a geological environment [16, 17, 18, 19]. The methods used in the COACH project [12] were based on Bachu et al. [9, 10] and used in the COACH database to estimate the storage capacity of hydrocarbon fields. Estimates made by the China University of
Petroleum Beijing (CUPB) applied an adapted version of the Tanaka et al. [18] method for computing the storage capacity in the Shengli oilfield complex [13].

The two methods proposed by the CSLF task force [8] and the EOR methodology of CUPB developed from methodology of Tanaka et al. [13] are basically identical in their approach. Both methods are based on a volumetric approach and are applicable to site, regional and basin-scale CO₂ storage capacity estimates. Both can be considered as ‘simple’ equation models, which try to calculate an ‘approximation’ of a possible storage capacity. The methods gave almost equivalent results (Table 1) when applied to the Shengli oilfield complex [13, 15].

The long term behaviour of CO₂ in a storage site depends on a number of parameters: reservoir, caprock, fluids and time [11]. The solubility of CO₂ in formation water varies with the salinity of the formation water, the temperature and pressure of the formation. The dissolution of CO₂ in pure water increases with increasing pressure (and thus increasing depth) up to approximately 7 Mpa. On the other hand the CO₂ solubility in formation water decreases with increasing temperature and salinity and thus (normally) decreases with depth [20]. The result is that in general, the solubility of CO₂ in formation water decreases with increasing salinity of the formation water [19]. Nevertheless, at geological storage depth of 800 m or below, a significant amount of CO₂ will dissolve and be trapped in the formation water. However, the geological time period for these processes needs to be taken into account.

There are, however, some differences in the approach to CO₂ behaviour in the storage site. The CSLF method [8] works with replacement of oil, gas or formation water but does not directly incorporate dissolution of CO₂ into the formation water. The method of Tanaka et al. [18], on the other hand, operates with a free phase of CO₂ and takes into account dissolution of CO₂ in the formation water, but it does not consider the time period needed for CO₂ dissolution [12].

### 3.1. CSLF Methodology

The work with establishing internationally recognised standards for capacity assessments was initiated by the Carbon Sequestration Leadership Forum (CSLF) in 2004–2005 and a CSLF Task Force has been active since. The paper “Estimation of CO₂ Storage Capacity in Geological Media - Phase 2” [8, 9, 10, 21] published by the CSLF presents comprehensive definitions, concepts and methodologies to be used in estimating CO₂ storage capacity.

The methodology used for hydrocarbon fields yields theoretical storage capacity according to the methodology described by CSLF [8]. A number of scientifically based assessments are necessary in order to address the geological storage capacity resulting from the various trapping methods. The formation volume factor used for oil varies regionally and locally depending on the oil type. The formation volume factor used for gas should vary with depth as a function of pressure and temperature. Similarly the CO₂ density also varies with depth as a function of pressure and temperature. To reach effective storage capacity CSLF introduce a number of capacity coefficients representing mobility, buoyancy, heterogeneity, water saturation and aquifer strength, respectively and all reducing the storage capacity. There are however only few studies for estimating the values of these capacity coefficients including Vangkilde-Pedersen et al. [22], which was used to estimate this coefficient for the COACH project.

### 3.2. EOR methodology of CUPB and methodology of Tanaka et al. [18]

The storage capacity in the dissolution model of Tanaka et al. [18] is given as the displaceable volume plus dissolved volume of CO₂ in water in situ. During injection, part of the formation water is displaced by CO₂, and part of the CO₂ is dissolved in the remainder of the formation water (Fig. 2). Like other two-phase systems, the saturation of injected CO₂ in the formation depends on how the injected CO₂ passes through the formation, as gravity and viscous fingering phenomena will affect the sweep efficiency of CO₂ strongly [19]. The Tanaka et al. [18] methodology is further developed [13] for calculating CO₂ storage in combination with EOR.

The sweep efficiency of CO₂ depends on formation thickness, vertical permeability distribution and mobility ratio of the injected CO₂ and formation water [18, 23]. The mobility of a fluid in a porous medium is defined as the ratio of the effective permeability to the viscosity of the fluid [18, 23]. The solubility of CO₂ in formation water varies due to the salinity of the formation water and the temperature and pressure of the formation [18, 23]. As a
general rule of thumb, the solubility of \( \text{CO}_2 \) in formation water decreases with increasing salinity of the formation water [19]. The volumes of \( \text{CO}_2 \) that can be stored underground have been studied by various institutes in Japan based on the cumulative production of oil and gas. Oil and gas occupy only the top portion of the reservoir in an anticlinal structure and the remaining lower part is filled with water. The volume of the water portion may be tens of times greater than the oil and gas portion and can be used for \( \text{CO}_2 \) storage.

For aquifer reservoirs in anticlinal structures and oil and gas reservoirs and neighbouring aquifers in anticlinal structures that are well sealed by cap rocks, the technology of \( \text{CO}_2 \) flood and underground natural gas storage can be applied to estimate the volumes of \( \text{CO}_2 \) that can be stored. As described above, the model suggested by Tanaka et al. [18] uses the following equation for underground \( \text{CO}_2 \) storage in oil and gas reservoirs and neighbouring aquifers, and in aquifers in anticlinal structures:

\[
\text{CO}_2 \text{ storage capacity} = (\text{displaceable volume}) + (\text{dissolved volume of } \text{CO}_2 \text{ in water in situ}).
\] (1)

The assumption for this equation is that the \( \text{CO}_2 \) injected is in its highly dense phase. The saturation of injected \( \text{CO}_2 \) in the formation depends on the permeability of the formation and the property of the formation water (see above). The injected \( \text{CO}_2 \) often passes through only a limited part of the formation as given by the sweep efficiency. In the Tanaka methodology the \( \text{CO}_2 \) saturation and sweep efficiency are estimated from the performance of a pilot test of \( \text{CO}_2 \) flood and underground natural gas storage respectively and they assume the following values:

- Sweep efficiency: 50%
- \( \text{CO}_2 \) saturation: 20%
- Water saturation: 80% (The water dissolves \( \text{CO}_2 \) under the reservoir conditions.)

Other data necessary for the calculation are the structural area, effective thickness, porosity, etc., which are typically obtained from structural contour maps and wells.

4. Comparison of calculation

The hydrocarbon field storage capacity following the CSLF methodology is given as the displaceable volume of oil and gas multiplied with storage capacity factors:

\[
\text{MCO}_2 = \rho \text{CO}_2 r \times \text{URp} \times B \times \text{Seff} \
\] (2)

\[
\text{CO}_2 \text{ storage capacity} = (\text{CO}_2 \text{ density}) \times (\text{recovery factor}) \times (\text{volume}) \times (\text{efficiency factor}) \
\] (3)

\[
\text{CO}_2 \text{ storage capacity} = (\text{CO}_2 \text{ density}) \times (\text{displaceable volume}) \times (1) \
\] (4)

\[
\text{CO}_2 \text{ storage capacity} = (\text{CO}_2 \text{ density}) \times (\text{displaceable volume}) \
\] (5)

where:

- \( \text{MCO}_2 \): hydrocarbon field storage capacity
- \( \rho \text{CO}_2 r \): \( \text{CO}_2 \) density at reservoir conditions (best estimate)
- \( \text{URp} \): proven ultimate recoverable oil or gas
- \( B \): oil or gas formation volume factor
- \( \text{Seff} \): Storage efficiency factor (here it is fixed as 1 (100 %))

The storage capacity in the dissolution model of Tanaka et al. [18] is given as the displaceable volume plus dissolved volume of \( \text{CO}_2 \) in water in situ:

\[
\text{CO}_2 \text{ storage capacity} = (\text{Ef} \times A \times h \times \phi \times S_g / B_g \text{ CO}_2) + (\text{Ef} \times A \times h \times \phi \times (1-S_g) \times R_s \text{CO}_2) \
\] (6)

\[
\text{CO}_2 \text{ storage capacity} = (\text{displaceable volume}) + (\text{dissolved volume of } \text{CO}_2 \text{ in water in situ}) \
\] (7)
Here both the displaceable volume and the dissolved volume are depending on the sweep efficiency factor (i.e. the percentage of the total oil reservoir or pore volume which is within the area being swept of oil by a displacing fluid, as in a natural or artificial gas drive or water injection field), which again depends on formation thickness, vertical permeability distribution and mobility ratio of the injected CO₂ and formation water.

- \( E_f \) = Overall sweep efficiency, fraction
- \( A \) = Structural area, \( \text{m}^2 \) (projected structural area of formation)
- \( H \) = Effective reservoir thickness, m (formation thickness)
- \( \phi \) = Porosity (fraction, dimensionless)
- \( S_g \) = CO₂ saturation coefficient, (fraction)
- \( B_{gCO2} \) = CO₂ formation volume factor, \( \text{m}^3/\text{m}^3 \) (CO₂ coefficient in formation [reservoir volume/std. volume of CO₂])
- \( R_{sCO2} \) = CO₂ solubility in water, \( \text{m}^3/\text{m}^3 \)

The Tanaka et al. [18] methodology is further developed by Li et al. of China University of Petroleum Beijing (CUPB) [13] for calculating CO₂ storage in combination with EOR. The equation of EOR methodology of CUPB is [13]:

\[
M_{(CO2)} = M_1 + M_2 + M_3 + M_4
\]

where:
- \( M_{(CO2)} \) = total storage capacity of CO₂ (\( \text{m}^3 \))
- \( M_1 \) = storage capacity of CO₂ dissolved in oil and water in oil bearing reservoir
- \( M_2 \) = storage capacity of CO₂ dissolved in water-bearing formation in contact with the oilfield
- \( M_3 \) = storage capacity of CO₂ in the displaceable volume of oil bearing reservoir during CO₂ flooding
- \( M_4 \) = storage capacity of CO₂ from reaction with reservoir rock

\[
M_{(CO2)} = E_f \times A_{or} \times h_{or} \times \phi \times [S_o \times R_{s(CO2)} + (1 - S_o) \times R_{w(CO2)}] + h_{wf} \times A_{wf} \times \phi \times S_w + V_{co2o} + V_{co2w} + M_4
\]

where:
- \( E_f \) = overall sweep efficiency (fraction), \( E_f = 5\text{-}25\% \)
- \( A_{or} \) = area of oil bearing reservoir (\( \text{m}^2 \))
- \( h_{or} \) = thickness of oil bearing reservoir (m)
- \( \phi \) = porosity of oil bearing reservoir (fraction)
- \( S_o \) = oil saturation in oil bearing reservoir (fraction)
- \( R_{s(CO2)} \) = CO₂ solubility in oil (fraction)
- \( R_{w(CO2)} \) = CO₂ solubility in water(fraction)
- \( A_{wf} \) = area of water formation (\( \text{m}^2 \))
- \( h_{wf} \) = thickness of water formation (m)
- \( \phi \) = porosity of water formation (fraction)
- \( S_w \) = CO₂ solubility in formation water (fraction)
- \( V_{co2o} \) = volume of CO₂ for displacing the oil produced during CO₂ flooding
- \( V_{co2w} \) = volume of CO₂ for displacing the water produced during CO₂ flooding

The calculation of EOR methodology of CUPB expects a relative high dissolution of CO₂ into formation water and oil [13]. The average dissolved CO₂ in oil and water in oil bearing reservoir (\( M_1 \)) is 16\%, the average CO₂ dissolved in water-bearing formation (\( M_2 \)) is 75\%, and the average CO₂ stored by displace oil and water in oil bearing reservoir during CO₂ flooding (\( M_3 \)) is 9\%. The last storage factor (\( M_4 \)) is not considered, as these data is not available for the reservoirs in the Shengli Oilfield and is regarded as a long-term storage factor [13].
5. The dissolution of CO₂ in aquifers

The aim of geological CO₂ storage is the permanent removal of the injected CO₂ from the atmosphere. The buoyancy of the injected supercritical CO₂ leads to an upward gravity driven flow of CO₂ towards the top of the reservoir to form a plume below the caprock. The brine density increases with increasing CO₂ dissolution. Due to the low solubility of CO₂ in the brine, a large volume of brine is necessary to dissolve a given amount of CO₂. (CO₂ - liquid or supercritical - and water are immiscible, but CO₂ can dissolve in water). A downward gravity driven flow induced by the increased density of CO₂ saturated brine is necessary to contact this large volume of brine and therefore determines the long-term dissolution rate [24]. Two mechanisms mainly contribute to dissolution at the gas-water contact: in the beginning of CO₂ storage diffusion dominates, while later convective mixing dominates.

In the beginning, before the plumes of saturated brine have reached the bottom, the overall dissolution rate is essentially constant due to rapid convective overturn. At late times the saturated brine forms a gravity current propagating outward from the CO₂ source. Simple models of constant density gravity currents predict a power-law decay of the overall dissolution rate. Direct numerical simulations show similar decay but at slightly lower rates [24].

Comparing diffusion model simulations of the mixing of carbon dioxide (CO₂) and methane (CH₄) in reservoirs Oldenburg et al. [25] found, that for CO₂ storage in depleted natural gas reservoirs, the injected CO₂ will migrate to levels under the CH₄ layer of the reservoir by buoyancy flow). Once a gravitationally stable configuration is attained, CO₂ and CH₄ mixing will continue on a longer time scale by molecular diffusion.

A study by Leonenko et al., [26] shows much faster dissolution rates. They studied the engineering techniques for CO₂ geological storage, and found that the site selection and placement of the injection wells were not the only variables for storage capacity. They found, that with brine injection at 1 Mt/year, about 63% of the CO₂ will be dissolved in 200 years forming a plume of saturated brine that moves outwards from the stored CO₂ plume top. In the absence of brine injection there is negligible CO₂ dissolution after initial injection during the same time period. They found that it is possible to accelerate the dissolution of CO₂ in brines by pumping brines from regions where it is under-saturated into regions occupied by CO₂ during storage. For horizontally confined reservoir geometry, they found that it is possible to dissolve essentially all injected CO₂ within 300 years. Similar analysis by Tchelepi [27] indicates that dissolution trapping can be enhanced significantly by convective mixing in aquifers depending on thickness and permeability.

The rate at which CO₂ dissolves into the brine is a key constraint both in different methodologies and in the different sites where CO₂ is geologically stored. The Tanaka et al. [18] methodology is based on storage of free CO₂ of which a large proportion is dissolved CO₂ in the formation water. The methodology does not take into account the time period needed for the dissolution of CO₂ in the formation water, nor the pressure or temperature at the injection point. A comparison to Sleipner and other sites in operation shows that interaction between the mechanisms are complex and evolves in time, and depend on local conditions such as porosity, permeability, temperature and pressure [28].
6. Conclusions

The two methodologies for calculation of CO2 storage capacity the CSLF [8] and the EOR methodology of CUPB [13] developed from the Tanaka et al. [18] both aim to quantify the potential CO2 storage capacity of depleted oil hydrocarbon reservoirs. Therefore, both can be considered as "simple" equation models which try to capture an "approximation" of a possible storage capacity. Nevertheless, several differences exist between these models. The EOR methodology of CUPB is operating with both a free phase CO2 plume and CO2 dissolved in the brine, while the CSLF method does not consider dissolution of CO2.

Understanding the dissolution process coupled to time, porosity and permeability, is important for predicting CO2 storage capacity. Local and site-specific storage capacity estimates should be based on numerical modelling that takes into account the dynamic aspect of CO2 injection and the CO2 plume evolution.

References

7. Table and figures

Table 1 Summary of geological sites assessed for CO2 storage [13]

<table>
<thead>
<tr>
<th>Storage Sites</th>
<th>Capacity</th>
<th>Injectivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shengli Oilfield complex</td>
<td>401Mt using the CSLF methodology</td>
<td>1000-2500mD.</td>
</tr>
<tr>
<td></td>
<td>483 Mt using the improved Tanaka et al. [18] method</td>
<td></td>
</tr>
</tbody>
</table>
Figure 1 Map of the study area in eastern China showing CO2 potential storage sites. Based on data from the Energy, Environment and Economy Research Institute, Tsinghua University; Institute of Geology and Geophysics, Chinese Academy of Sciences; China University of Mining and Technology; Research Institute of Petroleum Exploration and Development, PetroChina and the China University of Petroleum (CUP). The outline of the Shengli oilfield complex is from ‘Energy Map of China 2008’, © The Petroleum Economist Ltd, London. © British Geological Survey. British Geological Survey produced the GIS map.

Figure 2 Conceptual model for the storage capacity after Tanaka et al.’s (1995) model in an oil-gas reservoir in an anticlinal structure. The figure shows advection of a stably stratified the light gas (CH4) on the top and the heavy gas (CO2) below. Further the dissolution of CO into the brine.