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Well completion and integrity evaluation for CO_2 injection wells

Mingxing Bai[a,b,*], Jianpeng Sun[a], Kaoping Song[a], Lili Li[c], Zhi Qiao[b]

[a] Department of Petroleum Engineering, Northeast Petroleum University, Daqing 163318, China
[b] Institute of Petroleum Engineering, Clausthal University of Technology, Clausthal-Zellerfeld 38678, Germany
[c] No. 4 Oil Production Plant, Daqing Oilfield Company Limited, Daqing 163318, China

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ABSTRACT

Sequestration of CO_2 in depleted oil and gas reservoirs, coal seams and saline aquifers is one important means of mitigating greenhouse effect on the environment and enhancing oil and gas recovery. The collected CO_2 is injected via injection wells into the underground space. Due to the characteristics of supercritical CO_2, e.g., corrosive, low temperature, the well design and completion for CO_2 injection purposes requires more considerations. This paper introduces the basic challenges of designing a CO_2 injection well, reviews the famous CO_2 injection cases around the world, and proposes well completion criteria, including completion scheme design, materials selection and so on. Well integrity tests in use are reviewed and evaluated in terms of their pros and cons. Well integrity evaluation using numerical simulation is conducted as well to study the influences of CO_2 injection on well integrity in a pilot area in Germany. The results show that the materials selected for CO_2 injection well shall adapt to the low-temperature environment, and the cement should have a high tensile strength and resist corrosion. Under the impact of salt rock creep, the cement cracks resulting from temperature decrease during injection tend to heal. At the end of the paper for the wells with loss of integrity, a remedial work needs to be done, e.g., cement repair, and for this a thorough review of cement repair experiences is performed.

Contents

* Corresponding author at: Department of Petroleum Engineering, Northeast Petroleum University, Daqing 163318, China.
E-mail address: baimingxing@hotmail.com (M. Bai).

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1. Introduction

The rising CO_2 concentration in the atmosphere is one of the main reasons for the anthropogenic greenhouse effect. For this, the sequestration of CO_2 in the depleted oil and gas reservoirs, coal seams and saline aquifers is one means to mitigate this effect. It has been successfully implemented in the past decade, for example, RECOPOL (Reduction of CO_2 Emission by Means of CO_2 Storage in Coal Seams in the Silesian Coal Basin of Poland), Sleipner offshore aquifer storage in Norway [1], and onshore gas field In Salah. This paper is part of the study CO_2 Sequestration and Enhanced Gas Recovery (CSEGR) performed in the Altmark gas field in North Germany which is the second biggest onshore gas field in Europe. This project, which the authors have participated, is still in the process of feasibility study [2–4]. The reservoir has a depth of about 3400 m and is located in the geological Rotliegend formation. The caprock above the sandstone is salt rock with a permeability of 0.1 nD, which is a natural barrier for the migration of formation fluid. Supercritical CO_2 is injected into the underground space using two options. One is to use the existing injection wells or producers with proper remediation. The other one is to drill new wells. No matter which method is utilized, the well design and completion require more comprehensive considerations, e.g., the effect of corrosion on casing and cement, and the low temperature effect etc.

The wells involved in CSEGR have to meet the requirement of successful long-term containment of the injected CO_2 over two phases: injection phase and storage phase. Therefore wellbore integrity needs to be evaluated prior to the start of injection. The NORSOK D-010 standard describes well integrity as “the application of technical, operational, and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of the well [5].” Life cycle includes from well construction, monitoring, production to abandonment. Different types of tools are proposed to monitor the wellbore integrity conditions [6,7]. Besides, there are many risk-based assessment methods available proposed by, for example, Watson et al., Le Guen et al., and so on [8–11]. Some used analytical and numerical simulations to study the casing-cement-rock composite system mechanical integrity [12]. The other task of this paper is to evaluate the mechanical well integrity for a well in the pilot area using numerical simulation techniques. At the end, for the wells with loss of integrity, a remedial work needs to be done, e.g., cement repair, and for this a thorough review of cement repair experiences is performed.

2. Challenges of well completion for CO_2 injection wells

CO_2 injection wells are used in CSEGR operations to inject CO_2 in supercritical state, i.e., at pressure and temperature greater than critical state (73.8 bar and 31 °C). Fig. 1 shows the flow path of CO_2 injection into reservoir and the main issues encountered in this process. One important challenge is the Joule–Thomson cooling effect at the wellhead. After flowing through the chokes or valves, CO_2 is going to expand, which will generate a low temperature around the wellhead. This phenomenon is called Joule–Thomson effect. The outcome is a loss of wellhead integrity and malfunction. To overcome this, dehydrating measures should be taken. General statement for construction of new CO_2 injection well is that it is should be ideally placed at the flank of a storage anticline [13]. Besides, the Joule-II study has concluded that CO_2 should be injected in the reservoir at depths of greater than 800 m to ensure that it remains in a supercritical state [14]. Other issues such as CO_2 delivery, phase changes, perforation and so on are also playing a crucial role. In this paper the focus will be on the corrosion effect of CO_2 on casing and cement, as well as the well integrity problems.

2.1. CO_2 corrosion on metallurgy

The biggest challenge CO_2 injection wells will meet is the corrosion fatigue of metals. The affront of galvanic corrosion, pitting- and trough corrosion as well as crevice corrosion are mostly causing local limited damages, which can lead to small leakages in the metal. Crevice corrosion is a localized type of corrosion occurring in systems containing oxygen and is most intense when chlorides are present. In a crevice system metal is in contact with an electrolyte but is in short of oxygen. At the anodic site the metal goes in solution while at cathodic site the reduction of oxygen to form hydroxyl ions. The presence of chlorides tends to accelerate the crevice corrosion [15]. In the presence of an aqueous phase CO_2 dissolves in water and produces carbonic acid (H_2CO_3) which promotes an electrochemical reaction with steel. The resulting carbonic acid is corrosive and forms a scale of iron carbonate as corrosion product on the surface of the metal. Collapse of small bubbles within high velocity fluids tend to create shock waves of high pressure and result in loss of metal from the surface in contact [16].

All these corrosion types are causing material removal and consequently the metal becomes thinner. Hydrogen-induced and sulfide stress cracking are often concerned with the consequence of material fatigue. Characterized by a maximum tensile and yield strength, the metal has a maximum loading and endurance limit. However, corrosion effects are one of the main reasons for

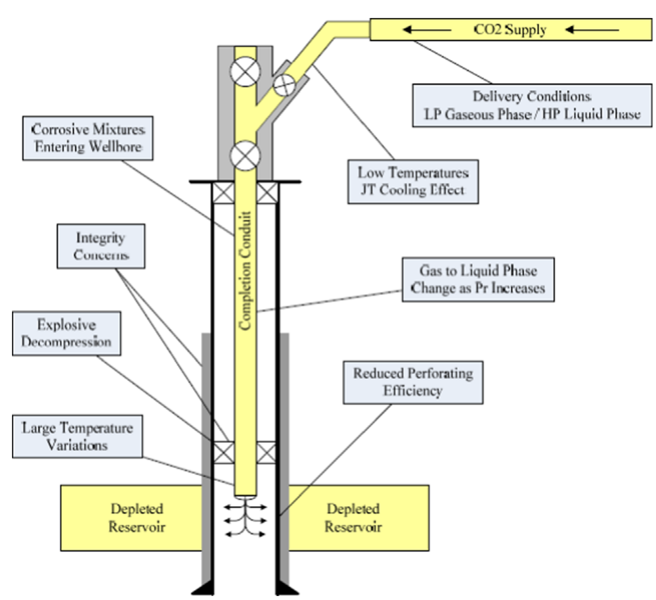

Fig. 1. CO_2 injection flow path [20].

material failure, long before the metal has reached its normal strength capacity.

2.2. CO_2 corrosion on cement

CO_2 also attacks the cement of the well and causes severe corrosion effects. Therefore the compressive strength decreases and the permeability and porosity of the cement increase. The reaction of Portland cement, which is most commonly used in the petroleum industry, with CO_2 is generally simplified as reaction with calcium hydroxide ($Ca(OH)_2$). According to Strazisar et al. [17] and Benge [18], the process can be described with the following reactions:

$$CO_2 + H_2O \leftrightarrow H_2CO_3$$

$$H_2CO_3 + Ca(OH)_2 \rightarrow CaCO_3 + 2H_2O$$

$$C\text{–}S\text{–}H + H_2CO_3 \rightarrow CaCO_3 + \text{amorphous silica}$$

In the initial reaction carbonic acid is built out of dissolved carbon dioxide and water. Then the acid reacts with calcium hydroxide and the calcium–silicate–hydrate gels and forms calcium carbonate.

$$CaCO_3 + H_2CO_3 \rightarrow Ca(HCO_3)_2$$

$$Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3 + 2H_2O$$

The calcium carbonate continues to react with the carbonic acid and builds water-soluble calcium bicarbonate. The last reaction is very critical, because the formation of water allows dissolution of more CO_2.

Many experiments conducted for studying of degradation of cement under the influence of CO_2 have been carried out by researchers. For example, Duguid found that temperature has more influence on the degradation than pH, and pH of 2.4 and temperature of 50 °C represent conditions for the most severe degradation which is analogous to sequestration at depth of 1 km in sandstone formations [19]. His results contradict with those of Islam which have shown that leaching rate occurred with square root of time [20]. Duguid attributed the difference to slowing of reaction in the batch process. Gouedard in his experiments concluded that the alteration process is more efficient in wet supercritical CO_2 phase than in CO_2 dissolved water. His model predicts that in 20 years the alteration front thickness will move 110 mm and 90 mm for supercritical CO_2 and CO_2 dissolved water, respectively [21]. On that basis, the average daily front thickness will be 0.015 mm/day and 0.0123 mm/day for the two media, respectively.

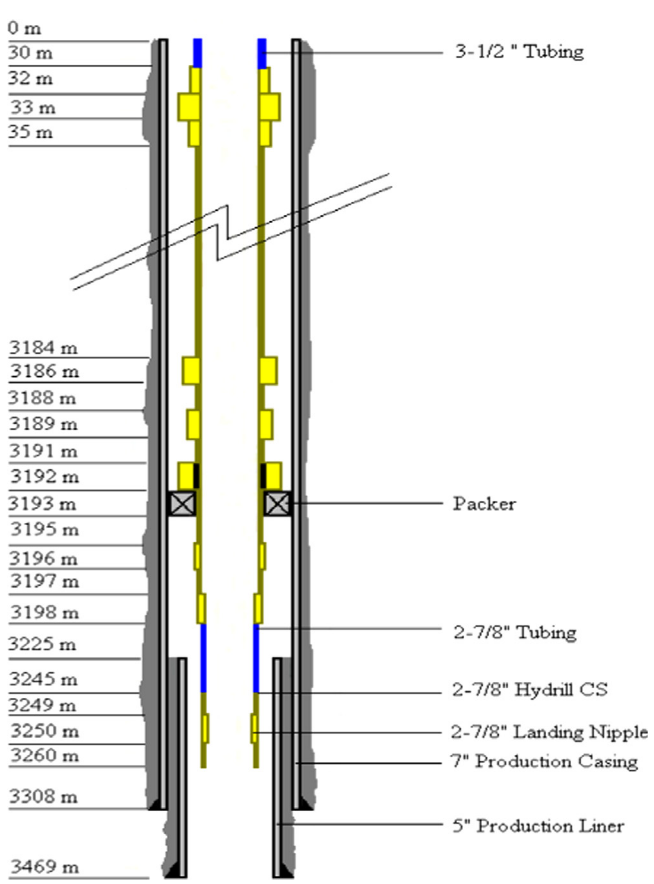

Fig. 2. Completion scheme.

2.3. Completion requirements for CO_2 injection wells

To achieve the goal to build an injection well with maximum economic lifetime, it is important to avoid corrosion effects by CO_2 and water or to keep them as low as possible. Therefore the injected CO_2 is compressed through multi-stage compressors accompanied by liquid removal and dehydration in every stage up to injection pressure. Usually a four stage centrifugal or reciprocating compressor system is used to increase the CO_2 pressure to the required pressure of injection. Compressor is equipped with suction scrubbers and discharge cooler for each of the four compression stages. The suction scrubbers remove traces of liquids in the stream and the coolers remove heat generated in compression, causing water to condense in the second and third stages [22].

The period for CO_2 sequestration projects is typically 10 to 50 years for the operation phase and 100–10,000 years for the post injection phase [8]. According to lab experiment conducted for the pilot area, in order to ensure an adequate strength of the steel tubular after corrosion, at least during the injection phase, corrosion rates are not significantly higher than 0.1 mm/year. Only when this value is taken into consideration, a safe operation within the operation period without workover could be possible. For the material of the coolers, downstream piping, vessels and other equipments, stainless steel is recommended. The completion of a CO_2 injection well has to meet high technical requirements, which differ from project to project. Generally it has to be gas-tight and can resist high pressures, mechanical loads from the rock and its own weight.

3. Completion scheme and material selection

3.1. Completion scheme

Fig. 2 shows the completion scheme of a CO_2 injection well in the pilot area. A 7 in. production casing is used, which is cemented over its whole length of 3308 m. A 5 in. production liner, which is 244 m long, is set to reach the production horizon. Near the surface at 30 m a landing nipple is installed. The 3 1/2 in. tubing string has a length of 3198 m. At its end there is a 2 7/8 in. Hydril CS connection with a 2 7/8 landing nipple.

As a normal completion procedure, a casing shoe is used to guide the casing string into the open hole. To make the well more safe it is absolutely advisable to complete the well with a subsurface safety valve (SSSV). It can be used to hold tubing pressure from below and prevent the backflow from the reservoir when the reservoir pressure increases to a limit value. To set a SSSV one nipple should be located near to the surface. And to set downhole devices a landing nipple at the end of the tubing string is useful. It has to be checked whether flow couplings have to be used or not, because SSSV and downhole devices can lower the inner diameter of the injection string, so they can help to reduce turbulent flow and give a better protection against erosion failure.

The wellhead consists of tubing head, tubing hanger, flange, and lower master valve and so on. The primary components which are directly exposed to the corrosive CO_2 should be corrosion resistant alloys or be coated with corrosion resistant Inconel overlays while those components not directly exposed can be coated with materials like Teflon [22]. The casing head, tubing head and casing valve can be made of carbon steel. It is also recommended to have the minimum amount of seals and connections in the wellhead and Christmas tree, so that the leakage risk can be minimized. For example, the multi-bowl wellhead is suited for CO_2 injection because it has a reduced amount of spools, flanges and sealing elements.

The packer, as a barrier between the reservoir and the casing/tubing annulus, should be retrievable and has to meet the demands of specific downhole conditions, for instance, hostile corrosive conditions. The proposed packer for injectors is hydraulically set permanent production packer. For the injection packers used in Jedney Field in Canada for disposal of acid gas, the inner mandrels and packer bodies below packer sealing element were made of Incoloy [22].

3.2. Cement material selection

The cement selected for drilling a new well or squeeze cementation has to be no less resistant to CO_2 than the conventional cement. Classified by the American Petroleum Institute, there are eight different cement types of API Standard Portland cement (from A to H) that are suitable for different temperature and pressure ranges. A Portland cement system can be readily modified in a number of ways to slow or prevent the reaction with CO_2. To maximize the ability of the sheath to maintain chemical and thermal integrity, it is necessary to lower the water-to-cement ratio to decrease cement matrix permeability, and to reduce the amount of products that could react with produced and injected fluids by optimizing Portland-based cement with selected components, or using a cement system that does not react with CO_2, e.g., Calcium Phosphate Cement (CPC).

In addition to the API classified cement, some cement materials of special types can be used for cementing wells. Table 1 provides an overview over available CO_2 resistant cements. These cementitious materials include basically reduced Portland, whereby $Ca(OH)_2$ and C–S–H are partly replaced by other components such as Calcium phosphate, alumina; or Non-Portland cement, whereby $Ca(OH)_2$ and C–S–H are totally replaced by other components [23–27].

3.3. Steel material selection

The selection of corrosion resistant alloys and lining material is based on the nature of the downhole environment. For example, the presence of conditions, like high reservoir water saturation or W-A-G (Water Alternating Gas) method of injection, promotes rapid corrosion of casing below the packer, which means the presence of such conditions warrants usage of corrosion resistant alloys such as Duplex stainless steel. At the Jedney field in Canada, the casing-tubing annulus was filled with inhibited water to minimize the corrosion and maintain its integrity for safe injection operations and subsequent storage of CO_2 [22].

Lab experiments have been conducted to analyze the corrosion behavior of two low-alloyed steels (38Mn6/C75; X65), one 13Cr-steel (X20Cr13), one austenitic-ferritic steel (Duplex), CrNi-steel (1.4462) and one austenitic CrNi-steel (1.4539) [28]. The tests were conducted under supercritical CO_2 conditions in the presence of water phase. The temperature ranges from 50 °C up to 130 °C and the pressure ranges from 80 bar to 215 bar.

The results in Fig. 3 shows that in the presence of water phase due to water condensation, the corrosion rates for carbon steels are from 5 to 15 mm/year, which is highly corrosive. Even the corrosion resistance of 13Cr-steel is with 0.3 up to 0.8 mm/year not acceptable. Also the two CrNi-steels 1.4462 and 1.4539 slightly exceed the accepted maximum corrosion rate of 0.1 mm/year, but local corrosion was not found. As a conclusion, the use of 13Cr-steel can be recommended, because under operational conditions this material has a good resistivity against corrosion. But under heavy corrosive conditions with separate water phase the Duplex steel 1.4462 and the super austenitic steel 1.4539 achieve much smaller corrosion rates. So the choice between these three steels only depends on the costs.

3.4. Completion comparison of four international CO_2 injection wells

In the Jedney gas field of New England in Canada two wells were completed to inject a mixture of 50% H_2S, 48% CO_2 and 2% CH_4. The formation is 1487 m deep, has a temperature of 65 °C and a current reservoir pressure of 50 bar. They used a 7 in. MN-80 casing, 34.2 kg/m and 3 1/2 in. L-80 tubing with 13.7 kg/m and Hydril CS premium connections [22]. Another project is the injection of 65% H_2S and 35% CO_2 in the LaBarge area of Wyoming, USA. The casing materials which they used for the two injection wells are SM-2550, P-110 and L-80 [25,10]. In the Sleipner Ost Field in Norway CO_2 is re-injected into the reservoir which is approximately 800 m deep, has a pressure of 80 bar up to 110 bar and a reservoir temperature of 37 °C. The applied material for the casing and tubing is 25 Cr Duplex steel [23]. Another project is the CO_2 injection at the Reedijk-1 gas well in the Netherlands. In 1992 the well had been completed with 3 1/2 in. Carbon Steel (CS) tubing and taken into production in 2003. After a year of CO_2-injection a downhole video camera identified a leak and severe pitting at the couplings. So they decided to do a workover and installed a 5-in. 13 Cr tubing [29]. The API steel grade L-80 belongs to the category of Chrome steel. It can be concluded that all above-mentioned wells are completed with a minimum of 9 Cr steel. The

Table 1
CO_2 resistant cements (13, 14, and 18).

Name	Description
Pozzolanic Portland cements	Pozzolanic materials blended with Portland cements to produce light weight slurries. The addition of Pozzolanic can reduce permeability and minimizes chemical attack from corrosive formation water
Micro-fine cements	Cements composed of very finely ground cements of either sulfate-resisting Portland cements, Portland cement blends with ground granulated blast furnace slag, or alkali-activated ground granulated blast furnace slag. Average and maximum particle size is 4–6 and 15 μm, respectively. These cements penetrate small fractures and harden fast
Expanding cements	Expanding or swelling cements are available primarily for improving the interface between cement and casing or between cement and formation
Latex cements	Latex cements are blends of API Class A, G or H cements with the polymer latex added. The additive may protect the cement from chemical attacks, such as formation water containing carbonic acid. Latex improves the hardened cements' bonding strength, elasticity, as well as filtration control of the cement slurry

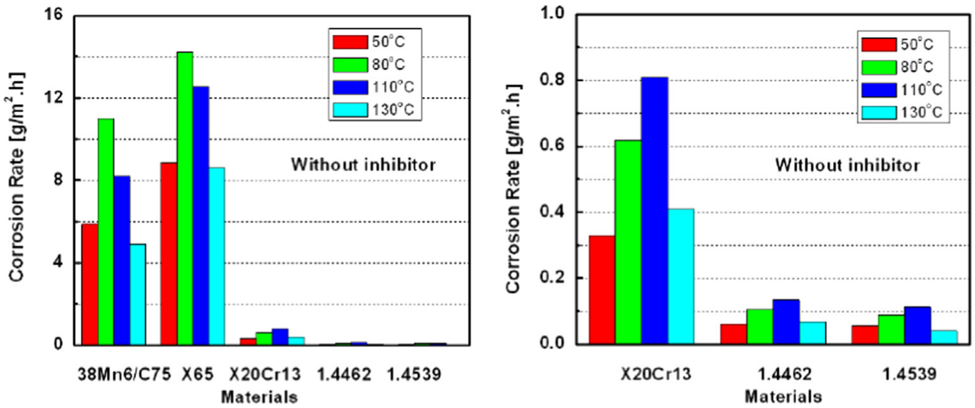

Fig. 3. Temperature effect on material corrosion in water saturated with $scCO_2$ [11].

only well that had been completed with Carbon Steel failed after nine months of CO_2 injection and had been recompleted with Cr 13.

4. Well integrity test and evaluation

4.1. Well integrity test

Mechanical integrity of CO_2 injection wells can be determined with the following tests which have varying degree of accuracy and pros and cons [30]. The existing equipment, man-power and cost influence the choice of them. The type of wells, operation philosophy and existing legislation dictate the nature and frequency of testing of the wells.

Standard Annulus Pressure Test (SAPT) relies on the principle that pressure applied to closed system with a fixed volume, e.g., casing and formation annulus, will be maintained if there are no leaks in the system, even when the pressure is removed. The test is performed with water as pressurizing agent. N_2 or compressed air can also be used as pressure source. Though easy to interpret and inexpensive to perform, it is unable to detect bad primary cement jobs or leakage by-passing the shoe.

Radioactive Tracer Survey (RATS) involves adding of radioactive (RA) tracers usually to injectant and then detecting the tracers with the RA detector run on wire line. Iodine-131 is usually used because of its short half life (8 days) while other tracers used for special applications. This test is expensive, and difficult to handle radioactive material.

Temperature Log is a record of temperature gradient of a well. The reference is geothermal gradient, taken before production or recorded when well is shut-in. Interpretation, which is difficult and requires high expertise, is done by looking for anomalies or departures from reference gradient.

Noise Log is a record of sound measured at different points along the wellbore. Sonic energy travels for a considerable distance through solid, allowing sensitive microphones to detect effects of turbulent flow at some distance. It can be used to identify flow of gas and can differentiate it from flow of liquid. Compared to temperature log, there is little or no shut in time, but it can identify only turbulent flow, and cannot demonstrate confinement.

4.2. Well integrity evaluation using numerical simulation

A case study is performed in order to investigate injection well integrity using numerical simulator FLAC 3D. The geometry and material data are shown in Tables 2–4. The objective of the simulation is to study the influences of CO_2 injection, or temperature variation, on well integrity, and determine the critical temperature drop values. The simulation results have been applied in the pilot area as guidance for CO_2 injection design.

Table 2
Geometry data of the wellbore.

	Outer diameter (mm)	Depth (mm)	Thickness (mm)	Class
Casing	177.8	2770–2900	11.51	P110
		2900–3310	12.65	
Liner	127	3250–3275	9.19	P110
		3275–3470		N80

Table 3
Parameters of casing, cement and rock.

Parameters/unit	Symbol	Cement	Casing	Sandstone	Salt rock
Bulk modulus (MPa)	K	4.7619e3	1.75e5	5.376e3	
Shear modulus (MPa)	G	4.3478e3	8.0769e4	3.702e3	
Young's modulus (MPa)	E	1e5	2.1e5		23,363
Poisson ratio (–)	ν	0.15	0.3		0.3
Internal friction angle (°)	Φ	29		37.5	
Density (1E6 kg/m^3)	ρ	2400e−6	7900	2260	
Strength (MPa)	F		861.5 (P110) 655 (N80)	3.69	
Cohesion (MPa)	c			17.28	
Kelvin shear module (MPa)	$\overline{G}_k^*$				1.4e04

Table 4
Thermal parameters of casing, cement, and salt rock.

Material	T (°C)	Specific heat, (J/kg K)	Thermal conductivity (W/m K)	Thermal expansion coefficient (K^{-1})
Casing		480.0	48.0	1.2e−4
Cement		1880.0	0.87	1.6e−4
Salt rock	25	826	5.51	4.2e−5
	50	867	5.1	
	100	876	4.26	
	180	890	3.33	

4.2.1. Simulation process

From the very beginning of a gas well, it undergoes a series of processes including drilling and completion, gas production, CO_2

injection, and well abandonment, etc. The cyclic temperature and pressure loading during the life time will pose potential integrity issues. Hereunder a numerical simulation is conducted to study the mechanical integrity of a CO_2 injection well in the pilot area. The simulation covers three steps including model building (drilling phase), salt creep (production phase), and CO_2 injection phase.

Phase of model building: The process of building a model is essentially the process of drilling, viz. hollowing out a solid cylinder. Three sections of the wellbore, which are Section AB (Segment 1), CD (Segment 2), and EF (Segment 3), are chosen for simulation, as shown in Fig. 4. Segment 1 is single casing completion, and Segment 2 is double casing completion. In this article only the results for Section AB are discussed since Section AB is surrounded by salt rock, whose creep property is our primary interest of the simulation. The model is subjected to a series of initial and boundary conditions. The initial stress distribution is calculated using Eqs. (1)–(3).

$$\sigma_r = P_i \times \frac{r_i^2}{r^2} + \frac{\sigma_{10}+\sigma_{30}}{2} \times \left(1-\frac{r_i^2}{r^2}\right) - \frac{\sigma_{10}-\sigma_{30}}{2} \times \left(1-\frac{4r_i^2}{r^2}+\frac{3r_i^4}{r^4}\right) \times \cos 2\theta \quad (1)$$

$$\sigma_\theta = -P_i \times \frac{r_i^2}{r^2} + \frac{\sigma_{10}+\sigma_{30}}{2} \times \left(1+\frac{r_i^2}{r^2}\right) + \frac{\sigma_{10}-\sigma_{30}}{2} \times \left(1+\frac{3r_i^4}{r^4}\right) \times \cos 2\theta \quad (2)$$

$$\tau = \frac{\sigma_{10}-\sigma_{30}}{2} \times \left(1+\frac{2r_i^2}{r^2}-\frac{3r_i^4}{r^4}\right) \times \sin 2\theta \quad (3)$$

Phase of salt rock creep: The well has a production history of 30 years. Within this process, the salt kept creeping, so the process of salt creep is essentially the process of gas production. The

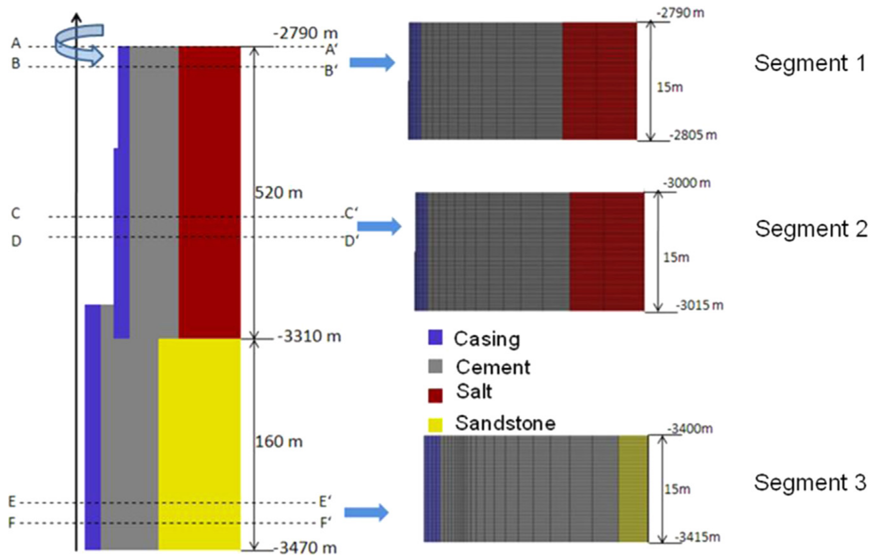

Fig. 4. Construction of the wellbore in the simulator FLAC 3D including three segments.

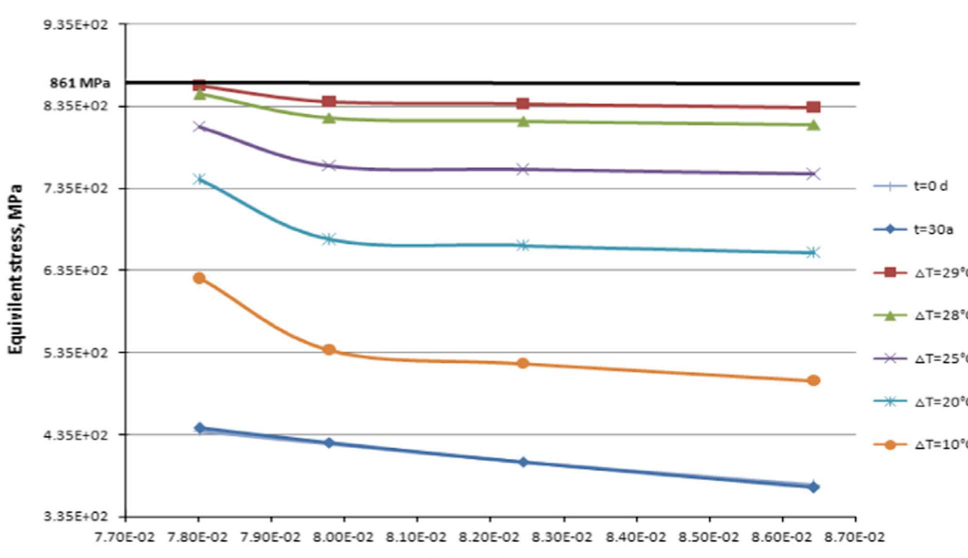

Fig. 5. Influence of temperature decrease on equivalent stress distribution.

stress state of the whole system is relatively stable, except the creep of the salt rock. To simulate this process, the elastic model is no longer applicable. Instead, the visco-elastic or visco-elastic-plastic model is used. The failure criterion for casing is von Mises criteria, and cement uses Mohr–Coulomb criteria. The salt creep results in an increased compressive stress, and the vertical stress increases with the depth.

Phase of CO_2 injection: After the salt creep comes the last step of the simulation which is CO_2 injection. The whole injection process is very complicated, and it needs to take many aspects into consideration, e.g., mechanical effect, chemical effect, and fluid solid interaction. In this article the focus is the effect of temperature drop on the stress distribution. For this two types of temperature drop are simulated. One is rapid temperature drop, and the other is gradual temperature drop with 1 °C/h. For rapid temperature drop, the temperature inside the casing drops dramatically after salt creep.

4.2.2. The influence of temperature drop on the stress distribution in the casing

Fig. 5 shows the effect of temperature drop on the equivalent stress distribution in the casing. It can be seen that when the temperature drop increases to 28 °C, there will be casing failure. A temperature drop till 29 °C leads to an equivalent stress inside the casing reaching the strength of the casing which is 861 MPa. A further temperature drop will lead to loss of casing integrity. As temperature decreases, the casing will shrink, which will generate a bigger shear stress. A bigger shear stress can increase the equivalent stress. Besides, the inner casing is going to fail firstly.

4.2.3. The influence of salt creep on the displacement after temperature drop

After a rapid temperature drop of 29 °C, the casing fails. In order to verify the integrity of casing-cement-rock composite system, three points are chosen. Point 1 is in the cement sheath near the cement-rock interface, Point 2 is at the interface, and Point 3 is in the salt rock near the interface, see Fig. 7. The casing shrinks due to decreased temperature, which will pull the cement inwardly. Therefore it is obvious that the points closer to the casing are going to have greater displacements, viz. Point 1 is supposed to have greater displacement, and the Point 3 has the smallest displacement. In Fig. 6 it shows Point 2 has the greatest displacement. This is because Point 2 is influenced by both casing shrinkage and salt creep.

Fig. 7 depicts the radial displacement difference between Point 1 and Point 2 (the Point 1 displacement minus the Point 2 displacement). The sign convention is that moving left is minus. At the very beginning of temperature drop, the displacement difference decreases. This is because Point 1 moves faster than Point 2 due to the casing shrinkage. There will be a potential crack in the cement. Later on, the lines goes up, which means the salt creep starts to have an influence. The salt creep might close the cracks in the cement. To check this, two different models are used, viz. elastic model and elastic-plastic model. It can be clearly seen that the displacement difference between the two points using the elastic model is much smaller than using the elastic-plastic model. This proves the effect of salt rock creep on the self-healing of cement cracks.

4.2.4. The critical temperature drop

The simulation tells us that the casing has a critical temperature drop value. After exceeding this critical value, the casing is going to fail. Table 5 shows the critical value for Section AB (Segment 1) and Section CD (Segment 2) for a rapid and gradual temperature drop, respectively. For Section AB, the critical temperature is 28 °C and 31 °C for rapid and gradual temperature drop, respectively. For Section CD, the critical temperature is 31 °C and 30 °C, respectively. It is obvious that for low grade and this steel (Section AB for example), the critical temperature is small. During the drilling process, if necessary, materials suitable for low temperature environment can be used.

5. Challenges and options of well remedial

To repair the cement, or the composite system behind the casing, means to heal the defects in the system behind the casing. Potential defects resulting in voids are channels, microannuli and small cracks. The defects can only be healed by introducing filling material, e.g., cementitious material. The commonly used method to repair defects in the cement sheath is squeeze cementation. Challenges of squeeze cementing are to locate the defects and to connect to the defects from the borehole by perforating. This may be difficult to achieve, for example, in the case of radial cracks resulting from cyclic loading. Further challenges are to characterize the defects and to design the repair, most importantly the slurry. To provide for a gas tight casing, a casing patch may be used to cover the perforations after the squeeze. If these conditions cannot be established, the second, but more expensive option is to mill the casing, underream the cement, set a liner across the milled section and cement it in place.

The repair of leaks in the cement sheath behind the casing with cementitious material is restricted to defects large enough to accept the cement slurry. Small cracks with apertures less than approx. 15 μm are outside the application range of this technique. The microfine cements have an average particle size of approx. 5 μm. Particles of this size will bridge in fissures less than approx. three times the size of the particles [31]. The radial cracks with apertures of 5–10 μm reported by Bachu and Bennion [32] and described in Teodoriu et al. [12] as the result of cyclic loading, e.g., ballooning and de-ballooning, during the operational life of a well can therefore not be remedied by use of cementitious materials. For small cracks and annular gaps of 4 and 12 μm Bachau and Bennion (2009) report effective permeability to brines reaching values up to the order of 1 mD. Connected larger voids in the cementation may be repaired by use of cementitious materials to provide a long-term gas tight well provided a connection can be established between the wellbore and the defects behind the casing and squeeze cement is chosen, which is able to penetrate the defect.

There is a general consensus among experts that the most successful method is the low-pressure hesitation squeeze with low fluid loss slurry and a packer or retainer as isolation tool. The high pressure squeeze technique is not recommended. Mixed results are reported on the success rate of squeeze operations. To mitigate this problem, best-practice guidelines are offered based on long field experience, which should be followed.

6. Conclusions

This paper has introduced the challenges of designing a CO_2 injection well during CSEGR. It has been found the corrosive downhole conditions are the biggest threat for well integrity, e.g., cement and metallurgy corrosion. Therefore, the well completion design for CO_2 injection has to take all the elements which might cause loss of well integrity during and after the injection phase into consideration, e.g., corrosion, erosion, cement degradation, leakage through tool connections, etc.

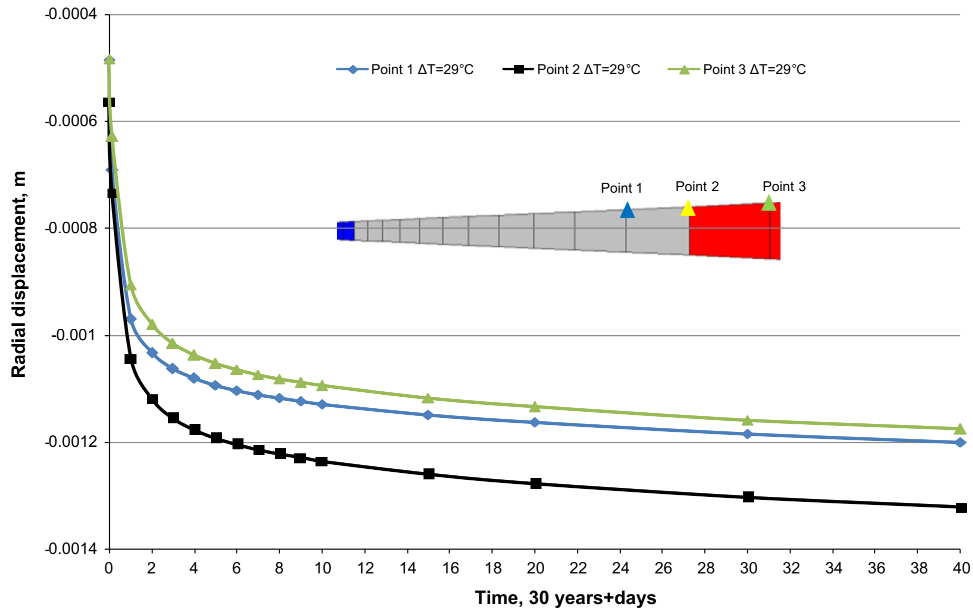

Fig. 6. Radial displacement in case of a rapid temperature drop 29 °C.

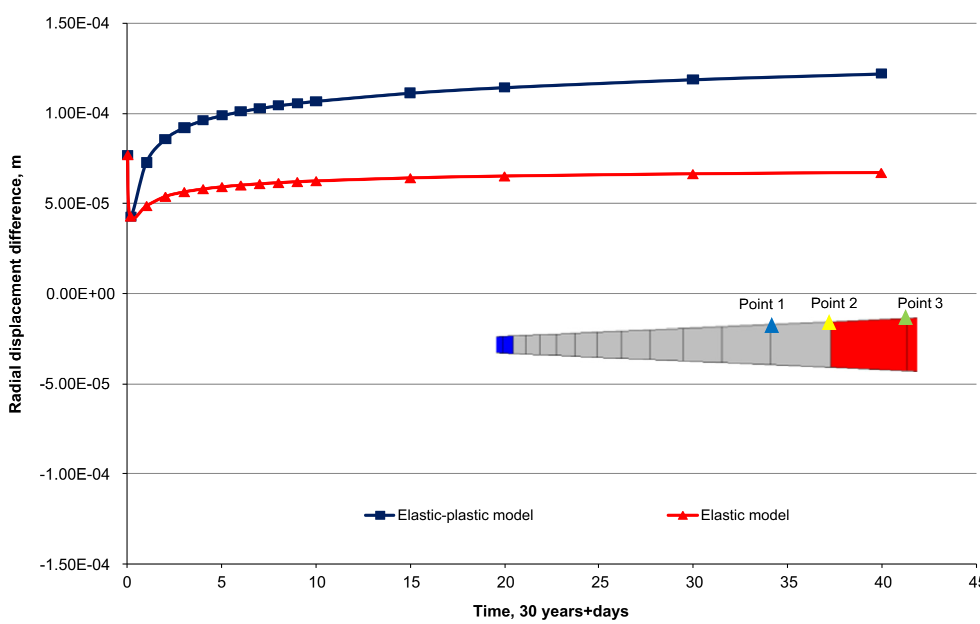

Fig. 7. Radial displacement difference of Point 1 and Point 2.

By researching the popular international CCS well completion, corresponding solutions have been proposed in terms of the material selection, completion scheme design, etc. Water saturated with supercritical CO_2 is very corrosive for steels. The 13 Cr steel with proper inhibitors is recommended for CO_2 injection well because it can provide a good corrosion resistance and has relatively low cost.

This paper also gave a thorough review of well integrity tests in use and evaluated their pros and cons. Well integrity evaluation using numerical simulation was performed as well to study the influence of temperature variation on the well integrity in the pilot area. It is found that the materials selected for CO_2 injection well shall adapt the low-temperature environment, and the cement should have a high tensile strength and resist corrosion. Moreover, the salt rock creep has a potential to make the cement cracks self-heal.

At the end, for the wells with loss of integrity, a remedial work needs to be done. For this, low-pressure hesitation squeeze with low fluid loss cement slurry can be implemented. A thorough review of cement repair experiences is performed.

Table 5
Critical value for the temperature drop.

	Rapid temperature drop	Gradual temperature drop
Section AB	28 °C	22 °C+9 °C=31 °C
Section CD	31 °C	22 °C+8 °C=30 °C

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