Well Engineering and Injection Regularity in CO_2 Storage Wells

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WELL ENGINEERING AND INJECTION REGULARITY IN CO_2 STORAGE WELLS
(IEA CON/17/245)

Key Messages

- The aim of this report is to highlight the key differences, and well engineering implications, for handling CO_2 in EOR and deep saline storage locations. These options are compared with conventional oil and gas wells. Best practice for CO_2 operations and the current understanding on handling CO_2 are also covered in detail.
- The ability to inject CO_2 regularly needs to be addressed in the planning stages of storage projects to assess future well performance. For wells exposed to formations containing supercritical CO_2 it is important to identify the procedures and equipment that have to be tailored for the specific characteristics of CO_2 (as opposed to hydrocarbon gas, oil or water).
- Industry experience with CO_2 EOR wells (both for CO_2 continuous injection as well as for CO_2-WAG) shows that new CO_2 injection wells can be suitably designed to allow well integrity to be maintained in the long-term. Concerns from cement degradation and corrosion can be suitably addressed in the design and construction of these wells. Industry experience also indicates that CO_2 storage injection wells can also maintain wellbore integrity if designed, constructed, operated and monitored as per current state-of-the-art design specifications and regulatory requirements.
- Risks from legacy wellbores can also be adequately addressed as long as sound engineering practices and compliance with current and more stringent regulatory requirements are complied with.
- The handling and managing CO_2 wellbore operations safely is well established from CO_2 EOR projects. Initial industry concerns about CO_2 injection, especially during the water-alternating-gas (WAG) process in terms of controlling the higher mobility gas; water-blocking, corrosion, production concerns, oil recovery, and loss of injectivity have been addressed with careful planning and design along with good management practices.
- Although there are a number of common areas between CO_2 EOR and CO_2 storage wells, the differences can be grouped under five broad categories: (1) operational, (2) objectives and economics, including CO_2 supply, demand and purity, (3) legal and regularity, (4) long-term monitoring requirements, and (5) industry's experience. There are no specific technological barriers or challenges per se in converting or adapting a pure CO_2 EOR operation into a concurrent or exclusive CO_2 storage operation.
- The costs associated with CO_2 EOR and CO_2 storage projects are site and situation-specific. In general, oil prices have by far the larger impact on the economic viability of a CO_2 EOR project, with the second largest impact being the cost of CO_2.

Background to the Study

This project focuses on collecting industry experience on the drilling, completion, regularity and interventions of CO_2 wells. The aim for the report was to compare methodologies and techniques used for handling CO_2 compared with those required for hydrocarbon extraction. This has allowed for a comparison to be made to the research already conducted on CO_2 well integrity and monitoring techniques. The study will investigate whether conditions experienced during CO_2 handling operations were predicted from modelling and experimental work and the effectiveness of linked risk assessments.

The differences between hydrocarbon and CO_2 operations are driven by acidification of drilling muds, the high expansion factor of CO_2 (going from liquid to gas phase), the effect of CO_2 on elastomeric seals and finally the cooling behaviour of CO_2 (which under uncontrolled depressurisation could chill equipment to temperatures below minus 70°C). Furthermore there is the potential to form CO_2 hydrates if water is present. Also, temperature and pressure cycling due to phase-wise injection (e.g. if CO_2 is delivered by boat) can strain the well equipment. Other wellbore integrity issues were also identified during a recent IEAGHG Modelling and Monitoring network meeting in July 2016. These included: timing and frequency of integrity log requirements; an improved understanding of cement pathways and a different (non-Darcy) approach to modelling flow in open wellbores. The choice of completion fluids could also be impacted by the presence of CO_2 in the injection tubing and the potential of acidification of annular fluids should a tubing leak occur.

Scope of Work

The study's primary objectives are:

- Gather well engineering and intervention experience from active CO_2 injection projects and from pure CO_2 production operators on the drilling, completion, regularity (the ability to actually inject CO_2 regularly) and interventions of CO_2 wells;
- Compare CO_2 EOR with CO_2 storage operations and summarize the best practices on CO_2 operations.

A secondary objective was to investigate whether conditions experienced during CO_2 handling operations were predicted from modelling and experimental work and the effectiveness of linked risk assessments. Injection regulations are not a focus of this report but have been included where relevant.

Six case studies were chosen based on the operational industry experience available on injecting or producing pure CO_2. The case studies represent a variety of operational settings (e.g. onshore, offshore, CO_2 injectors and CO_2 EOR).

A comparison with hydrocarbon wells was made which highlights the differences in experiences with CO_2 wellbores and wellbores used as standard within the oil and gas industry. The comparison highlights the implications these differences have when conducting risk assessments and also the associated costs of these alterations.

A compilation of discrepancies between predicted implications of pure CO_2 wellbores versus industry experience has been made. The report also reviews whether risk assessments currently being developed for CO_2 injection wells are appropriate and if improvements can be made in risk assessments particularly regarding the potential to identify and remediate wellbore integrity issues.

Findings of the Study

The study begins by outlining the current recommended practices for CO_2 well design. This includes a comparison to oil and gas wells which highlights that the design of a CO_2 injection well is very similar to a water/gas injection well in an oilfield or gas storage project, with the exception that much of the downhole equipment must be upgraded for high pressure and corrosion resistance. The cement and casing used for the well design is the biggest difference in comparison to a water/gas injection well, with CO_2 resistant cements and corrosion resistant alloys required.

Carbon dioxide corrosion and the effects on different materials and how to monitor injection wells is also covered in depth. The aggressive chemical components in the injected gas discussed in the report are:

- CO_2 – controls the basic material selection;
- H_2S – shifts the choice of materials significantly because of the risk of pitting and/or hydrogen loading;
- O_2 – introduces pitting risk; and
- SO_2 and NO_2 – make the environment more acidic.

The material selection guidelines for both EOR and pure CO_2 storage wells are discussed along with best cementing practices.

Key Injection Risks for CO_2 Wells versus O&G Wells

The report summarises the main well integrity issues for both CO_2 EOR and pure CO_2 injection wells and draws a comparison between handling hydrocarbons versus CO_2. Corrosion caused by CO2 is discussed extensively looking at potential construction materials and monitoring of injection wells and the causes of corrosion. The key issues when addressing CO_2 wells specifically (rather than hydrocarbons) are:

1. CO_2 is reactive and may be corrosive when mixed with water. The can affect well materials during injection such as the tubulars and cement as well as changing reservoir properties in the near wellbore region.
2. Injection rates may be high which can affect wellbore structure mechanically.
3. The large timescales required for storage will mean specific requirements for well design and monitoring procedures will need to be met.

For a CCS project the storage operation will have to store millions of tonnes of CO_2 within a 50 year time frame. Injectivity and injection regularity are therefore important to meet the large-scale storage required. Injectivity reduction after CO_2 injection has occurred frequently in West Texas as well as being reported in other locations. The variety of causes are listed in the report including the potential impacts on mobility and wettability due to interactions between oil and CO_2. Gypsum, calcite, high molecular weight paraffin and asphaltene production and deposition are also discussed. To be able to accurately predict the injectivity of a wellbore at specific sites more research is required although current reservoir modelling capabilities for CO_2 injection are discussed.

In terms of project design and development for CO_2 EOR operations oil recovery is the main focus for the project to be profitable, therefore wells are drilled to optimise recovery. For CO_2 injection minimising the number of wells whilst maximising storage capacity is the focus and hence fewer wells would be drilled in comparison to EOR sites.

If leakage did occur the main difference to hydrocarbons is that CO_2 is not explosive and hence fires are not the concern. The main hazard associated with CO_2 is asphyxiation as the gas is denser than air. CO_2 blowouts may have complications that other blowouts may not exhibit, due to the characteristics of CO_2. The tremendous expansion of supercritical CO_2 when pressure containment is lost is of great significance from a well control perspective. Rapid cooling occurs due to the expansion that occurs which can lead to the formation of dry ice and hydrates which can collect in various elements of the surface equipment.

The report provides an overview of the risks posed from potential loss of well control. Six CO_2 blowout case studies are included as examples e.g. cases in New Mexico, Colorado and Wyoming. Both human factors and unforeseen reservoir conditions can contribute to the loss of well control, and safety procedures, in-depth personnel training and specialized equipment is used to minimize their likelihood. The dynamic kill technique can be used to control a CO_2 blowout without the use of highly overbalanced kill fluids. This factor becomes important if flow restrictions, such as small diameter tubulars, limit fluid injection and rate. Failures from CO_2-related corrosion can cause the loss of well control. In some wells in CO_2 floods that were drilled in the 1940s and 1950s, cumulative corrosion impacts are a problem. It is important to make older wells equipped with corrosion-resistant tubulars and also wells that have been converted to CO_2 service.

The report summarises the key differences between oil and gas, CO_2 EOR and pure CO_2 storage wells in Table 8. This is provided on the pages below as a synthesis of the main focus for the report, to highlight how CO_2 wells vary from oil and gas standard practices.

Table 8 (in report) – Comparative Summary of Conventional Oil and Gas Injection Wells and CO_2 EOR and CO_2 Storage injection Wells

	Conventional O&G Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
High Injection/ Operating/ Reservoir Pressure Management	• Generally, not high for water injectors and oil/gas producers. • Important consideration in High Pressure High Temperature (HPHT), deep water and over-pressured reservoirs.	• A principal source of danger in a CO_2 facility is the high pressure (generally above 1,100 psi – 7.58 MPa) at which CO_2 is transported and injected (applicable for both CO_2 EOR and CO_2 storage facilities). • High pressure is particularly dangerous with CO_2 because of CO_2's high coefficient of thermal expansion – a small change in temperature can cause a large change in pressure. • Injection pressures are generally higher [~ (800 – 1,500 psi/5.52 – 10.34 MPa)] in CO_2 EOR wells than O&G production/injection wells. • Increased well pressures make workovers more	• High injection pressures combined with low injection fluid temperatures can induce hydraulic fracturing. • Regulations may require maximum injection pressure not to exceed 90% of the injection zone fracture pressure (US) or 90% of the fracture pressure of the caprock (Norway). • Geomechanical models are required to determine the maximum injection pressure that will not induce fractures and to determine the in-situ stresses and faults, and fault re-activation hazard. Injection wells should be located as far as possible from faults.
CO_2 Corrosion	• CO_2 corrosion is generally not a factor in conventional O&G production/injection wells. Significant factor in acid/sour gas injection streams with CO_2 and H_2S present. • In a study of the K-12B gas field in the Dutch sector of the North Sea where CO_2 is injected, 5% of tubulars were degraded due to pitting corrosion (Mulders, 2006).	• CO_2 reactivity in water may corrode injection well materials (well tubular and cement) and can also change the reservoir properties in near wellbore region. • In WAG operations wetted surfaces often use specialty metallurgy (316 SS) and coatings to guard against corrosion, • Long-term stability of wellbore materials in CO_2-rich environment is a complex function of material properties and reservoir properties which need to be incorporated into well design and completion programs.	• In CO_2 storage projects, if dry CO_2 (with CO_2 purity above 95%) is injected in the supercritical state the corrosion risk is low and therefore, corrosion problems are not expected to be any more severe as compared to CO_2 EOR operations (Nygaard, 2010). • The corrosion rate will increase if the injected stream comes into contact with water. Possible water sources may include: connate water in the injection zone, free water in the cement or free water resulting from capillary condensation (Kolenberg et al., 2012).

Table 8 (in report) – Comparative Summary of Conventional Oil and Gas Injection Wells and CO_2 EOR and CO_2 Storage injection Wells

	Conventional O&G Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
Well Design & Construction (Drilling/ Workovers)	• All wells have two basic elements: the wellbore, (which includes the packer) and the tubing and wellhead valves assembly. • Multiple casing strings are used for a variety of reasons, including the protection of groundwater resources and maintaining wellbore integrity. • Drilling in environments such as HPHT, deep/ultra-deep water, steam assisted gravity drainage (SAGD), extended reach drilling (ERD and ultra-ERD), arctic, shale oil and gas, hydraulic fracturing, salt zone drilling and CO_2 injection results in complex loading conditions on the casing/ tubular/cement etc. (most commonly used casing design software is WELLCAT™) See Section 2.1.2.	• Design and well construction of a CO_2-EOR injection well is similar to a typical oil and gas-related water injection well with most downhole equipment being virtually the same, except the wellhead. See Section 2.1.3 and Figure 4. • CO_2 EOR wells are either drilled as new wells or, as is quite common in existing fields, re-completed by converting producer or injector to a CO_2 EOR injector. • There are several major differences in wellbore remedial work between a water flood and a CO_2 flood (See Section 2.1.6). • Most operators with large CO_2 EOR operations (See Case Study # 4), maintain a workover rig on location for routine workover and maintenance. Ability to deploy a rig at short notice is also valuable in case a well control incident were to occur.	• A CO_2 storage well is in most cases similar to CO_2 EOR injection well, however, in some instances the design requirements for a CO_2 storage well may be more stringent, depending upon a case-by-case basis (See Section 2.1.4 and figures 5 and 6). • CO_2 will be stored for a long time period (decades). This imposes a number of requirements on the well design and specific procedures for its monitoring and abandonment as part of wider MMV (monitoring measurement and verification) requirements for the entire storage site depending on jurisdiction.
Well Integrity	• Conventional oil and gas wells have generally lower well integrity failure incidents than wells drilled in deep water, ERD, shale oil/gas and HPHT environments.	• Well integrity in CO_2 EOR wells needs to take account of exposure to corrosive CO_2, life of field and permanent entrapment of CO_2 within the reservoir. This is readily addressed	• Injection rates may be higher in CO_2 storage wells as compared to CO_2 EOR wells and can have impact on wells and near wellbore structures. • Some experimental observations like the abnormal pressure drop response obtained

Table 8 (in report) – Comparative Summary of Conventional Oil and Gas Injection Wells and CO_2 EOR and CO_2 Storage injection Wells

	Conventional O&G Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
(Well Integrity Cont.)	• Wells drilled in Gulf of Mexico indicate significant problems with SCP (sustained casing pressure), believed to be caused by gas flow through cement matrix (Crow, 2006). • In the Norwegian sector of the North Sea, ~13-15% of production wells experienced leakage, while 37-41% of the injectors experienced leakage (Randhol and Carlsen, 2008; and NPA, 2008). • Of ~ 316,000 deep wells analyzed in Alberta, 4.6% had leaks with gas migration occurring in 0.6% of the wells and surface casing vent flow (SCVF) in 3.9% of the wells (Watson and Bachu, 2007). • Main observation from these studies is that cased wells are more prone to leakage than drilled and abandoned wells, and injection wells are more prone to leakage than production wells (Nygaard, 2010).	by strict adherence to material selection requirements. • Largescale CO_2 EOR operations like SACROC and Wasson Field (See Case Study # 4, Sections 2.1.6 and 5.1) suggest no major issues with life cycle well integrity management. • Problems from CO_2 corrosion and impacts on cement degradation have been handled with appropriate selection of materials of construction (well tubulars and cements) in CO_2 EOR operations • Appropriate casing/tubing design to handle complex loads/stresses from CO_2 injection and CO_2 EOR operations have been successfully handled with appropriate casing/tubular design software. • Proper maintenance of CO_2 injection wells (both CO_2 EOR and CO_2 storage) is necessary to avoid loss of well integrity. Procedures to reduce loss of well control (LWC) incidents including blowouts and to mitigate the adverse effects if one should occur include: periodic well integrity surveys, improved BOP equipment maintenance, improved crew awareness, contingency planning and emergency response training.	under a high injection rate suggest that solid particle displacement can occur leading to severe permeability impairment (Cailly et al, 2005). Evidence from Sleipner field does not support this observation. Laboratory work should be performed on the injection formation to assure no adverse impacts from high rate injection. • After CO_2 injection, the CO_2 plume may move upwards or sideways due to pressure difference and buoyancy, with wells providing an obvious pathway for CO_2 to escape from the injection zone. • Intermittent supply of CO_2 (supply disruptions during unloading from a ship or during well interventions/repairs) can affect well integrity and injectivity. On-off injection leads to cyclical heating and cooling and can cause radial and hoop stresses in cement and lead to debonding (between cement and casing and/or rock) or disc or regular fractures. This can also have an impact on nucleation conditions (e.g.salt) and borehole deformation. The research-based advice is to avoid extensive pressure testing of annular barriers, ensure robust well construction, and minimize thermal cycling. The average time for well integrity problems to occur is ~ 2 years if wells are operated outside their initial design envelope and there is a strong dependence on quality of cementation.

Table 8 (in report) – Comparative Summary of Conventional Oil and Gas Injection Wells and CO_2 EOR and CO_2 Storage injection Wells

	Conventional O&G Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
Material Selection & Specifications	• For wells 10,000 feet (3,048 m) or less in depth, carbon steel casing is typically used with J-55 and K-55 grades being more common. • In deep water (drilling through salt), HPHT, shale oil/gas hydraulic fracturing, acid gas (CO_2 and H_2S), and CO_2 EOR and CO_2 storage, higher strength grades and/or corrosion resistant alloys (CRA) are used. (See Section 4.3). • Most conventional oil and gas wells use API Class G and H Cements for typical applications. Other types are also used for specific applications - thermal, HPHT, deep water, Arctic, shale oil/gas, geothermal etc. (See Appendix 5 and Tables A5-1 and A5-2). • Cementing is critical to the mechanical performance and integrity of a wellbore both in terms of its method of placement and cement formulation used.	• CO_2 may be corrosive or non-corrosive depending upon the materials employed, temperature at the contact surface, water vapour concentration, CO_2 partial pressure and velocity effects (See Section 4.0). • Material selection guidelines for CO_2 EOR wells are given in Section 4.3.3 and Table 6. • Reaction of CO_2 with wellbore cement is slow in a well in which good construction practices and appropriate materials were used; in these cases CO_2 should not be a problem (See Section 4.4 and Table 7). • SACROC core evidence indicates Portland cement system can provide the requisite wellbore seal for the lifetime of the project. Making modifications to the standard Portland system may further improve the long-term reliability of the seal. • Non-Portland specialty cements that are resistant to CO_2 are commercially available. Use of these systems requires planning and logistics (See Sections 4.4 and 4.4.3 and Appendix 5 and Tables A5-1 and A5-2).	• Material selection for CO_2 injection wells depends on high strength requirements combined with high corrosion resistance of the material. • A chemical analysis of the reservoir fluids is required for evaluation of the corrosive components such as temperature and pressure profiles and stresses on the tubulars should also be considered. • Material selection has to consider that wells will be in contact with wet CO_2 especially in the deeper section of the well. • Other factors to consider should include material capabilities for low temperatures (brittle materials may not be adequate protection for a CO_2 leak) and oxygen-related corrosion impacts (See Sections 4.3 and 4.3.2 for corrosion resistant alloys (CRAs - Tables 4 and 5). • Material selection guidelines for CO_2 storage wells are given in Sections 4.3 and 4.3.4. • CO_2 resistant cement properties have been tested and evaluated at CO_2 EOR sites (see opposite) and Section 4.4.

Table 8 (in report) – Comparative Summary of Conventional Oil and Gas Injection Wells and CO_2 EOR and CO_2 Storage injection Wells

	Conventional O&G Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
Injectivity and Regularity (ability to actually inject CO_2 at the desired rates necessary to store the delivered quantity)	• There are well established industry practices to address injectivity and permeability impairment or stimulation for conventional water injectors in oil and gas production. • Evidence shows loss of integrity much higher in injection wells compare to production wells – possible causes thermal cycling of fluids. • Changing use of well originally designed for a different purpose may compromise its re-use for a different function.	• Potential loss of injectivity and corresponding loss of reservoir pressure can have a major impact on the economics of a CO_2-EOR project (Rogers et al, 2001). Both injectivity increases and reduction have been observed in CO_2 floods including in several West Texas floods and the North Sea (after hydrocarbon injection). • Factors that affect injectivity include: low mobility in the tertiary oil bank; wettability; trapping and bypassing of gas; increased scaling; paraffin problems; asphaltene precipitation. Asphaltenes can plug up plungers, clog wellheads, tubulars, chokes, and surface/ production lines (See Section 5.2). • For EOR operations such as at Weyburn and Oxy's Denver Unit (See Case Study #4), the number and location of injection wells is part of the optimization program for oil recovery. Commercial CO_2 EOR operations need to take account of oil recovery and CO_2 recycling.	• CO_2 injection can alter mechanical properties of the reservoir rock by inducing chemical reactions. Precipitation of salts, mainly consisting of halite (NaCl), due to water vaporization can result in injectivity impairment around injection wells (Bacci et al, 2011, Hansen et al, 2013 and Sminchak et al. 2014). Some studies suggest that a high CO_2 injection rate should permit the injection process to continue with limited impact on injectivity even if significant halite precipitation takes place (See Section 5.3). • Fines migration can be remediated in theory by ensuring that injection proceeds at specific velocities large enough so that particle deposition occurs far enough from the wellbore. Borehole deformation in weaker/unconsolidated formations can be remediated by adding brine in the injector to re-stabilize the formation (Papamichos et al., 2010). • Geological heterogeneities resulting from faults intersection, reservoir compartmentalization or facies variation may be remediated by use of acid injection to open high permeable pathways from the injection well, or surfactants to alter the wettability of the lower permeability units and counteract the CO_2 trapping tendencies (Torsaeter et al., 2018). • Shale swelling can be addressed through concomitant injection of specific brine to restore salt balance (as is done when drilling through

	Conventional O&G Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
			shaley intervals) such as inflatable packers or blank pipe connections. • Where the size of the aquifer is large and the receiving formation has a high permeability (e.g. Utsira in Sleipner) CO_2 can be injected at a high rate without significant injectivity problems or a significant pressure increase. In less favourable locations, injectivity and injection regularity may become a crucial technical and economic challenge. Large scale storage of CO_2 requires reservoirs with sufficient capacity and good petrophysical properties to dissipate pressure build-up and avoid interference with adjacent oil and gas operations, if present.
Plugging **(P&A)**	• There are well established industry practices to properly plug and abandon conventional oil and gas wells. P&A of deep water offshore wells are more challenging and technological advances are being made to safely plug and abandon/decommission these wells and platforms. • Plugging and abandonment regulations for Texas are given in Texas Administrative Code (TAC) Title 16, Part I, Chapters 1 through 20 (See Section 7.1). Rule § 3.14 covers plugging requirements in Texas (RRC).	• Texas RRC Rule §3.14 covers plugging requirements for CO_2 EOR wells (See Section 7.1) and AER Directive 020 - Well Abandonment in Alberta, Canada (See Section 7.2). See Appendix 6 - Plugging and Abandonment of Wells for plugging procedure for CO_2 EOR wells. Please also see Table A6-1 - Description of Abandonment Methods.	• Many old, abandoned wells (completed and shut-in using practices and cement acceptable at the time) may not be suitable to use in long-term CO_2 storage systems. Leakage from abandoned wells has been identified as a potential "significant" risk in geologic storage of CO_2. Evidence from the Cranfield, Mississippi site (See Section A2.8) does not support this view, where a specific investigation of legacy wells showed no detected evidence of CO_2 leakage. This does not mean legacy wells could leak but it is a matter of degree, risk assessment and remediation. Also, legacy wells were not designed for handling CO_2 (See Section 2.1.6). • Operational conditions affect well integrity which might be relevant if legacy wells are then used for CO_2 injection or even if new dedicated

	Conventional O&G Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
(P&A cont.)	• P&A regulations for Alberta are given in Alberta Energy Regulator (AER) Directive 020 - Well Abandonment in Alberta, Canada (See Section 7.2). • API Bulletin E3 "Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations", 1993 gives additional guidelines on P&A requirements (See Appendix 6).		wells are used for CO_2 injection. Well design has to consider handling large volumes of CO_2 over several years with probably intermittent injection operations. • Storage in deep saline aquifers may also pose a lower risk (due to lower number of wellbores encountered) than those encountered in oil and gas fields. • Depleted oil and gas reservoirs are likely to incorporate a greater number of wells penetrating the reservoir caprock due to the historical exploitation of these fields. Seepage, migration, and leakage can occur from improperly plugged and abandoned old oil and gas wells. Since the operational history of CO_2 storage wells is relatively short compared to CO_2 EOR wells, we do not have actual examples of plugged and abandoned CO_2 storage wells to compare key differences in plugging practices between these two types of wells. See Appendix 6 for Recommended Best Practice for Well Abandonment from a CCS Perspective. • A good understanding of well abandonment and remedial measures and current abandonment practices and regulatory requirements are necessary to assure safe and secure long-term storage of CO_2 in the subsurface reservoirs. A variety of techniques are employed around the world to facilitate well abandonment and state and federal regulatory agencies may specify the exact requirements for doing so.

Case Studies

In total six case studies were included covering a variety of CO_2 injection scenarios including offshore, onshore, EOR and pure CO_2 storage. Core Energy's offices in Michigan were visited by Talib Syed and Associates as part of this study, the full details of which are included in the report. Three of the case studies are highlighted below:

Petrobras' Lula Field: Offshore Brazil

- Brazil's Pre-Salt layers deposits are currently the international leader in pursuing deep water offshore CO_2 EOR.
- Advantages of early implementation of CO_2 EOR as part of planned production included: improved capital efficiency since it freed the operator from subsequent retrofit of infrastructure and platform space, avoiding need to suspend or shut-in production.
- The CO_2 EOR design utilizes intelligent well completions, dynamic downhole monitoring, tracer injections and extensive CO_2 recycling.
- To improve reservoir management, intelligent completions are being deployed whenever considered beneficial. This approach can mitigate risks from preferential flow and early breakthrough and also allow injection of either water or gas.

Oxy Denver Unit, Wasson Field Texas

- Oxy operate the Denver Unit in the Permian Basin of West Texas for the primary purpose of enhanced oil recovery using CO_2 flooding (CO_2-EOR) with a secondary purpose of storing CO_2 for a specified period 2016 through 2026.
- There are ~1,734 active wells (2/3rd production and 1/3rd injection). Since 1996, all wells are cemented to surface using state-of-the-art standards. Oxy pays close attention to older wells and keeps well workover crews on site in the Permian Basin to maintain all active wells and to respond to any wellbore issues that arise.
- Oxy used simulators to model the behaviour of fluids within the reservoir and uses detailed pattern modelling to plan the location and injection schedule for wells. Simulations are also used to: evaluate infill or replacement wells; determine best completion intervals; verify the need for remediation/workover or stimulation; determine anticipated rates and ultimate recovery. Oxy uses commercially available compositional simulator MORE.

Overview of Core Energy's CO_2-EOR Projects

- Core Energy, LLC currently operates the only CO_2 EOR projects in Michigan and the only commercial EOR project east of the Mississippi. In addition to CO_2 EOR operations, Core Energy is involved in CO_2 sequestration in conjunction with EOR operations in Michigan by hosting a public/private partnership to research the storage potential of Michigan's oilfields and deep saline reservoir geology.

- They currently have 15 injection wells (12 converted and 3 new), 13 production wells (4 converted and 9 new), and 8 Monitor wells (6 converted and 2 new).
- In some of the new wells drilled, additives (e.g. latex) were added to the cement blends as a "belt and braces" type approach to help the cement be less porous and less susceptible to degradation, which has not occurred to date.
- Corrosion is limited due to absence of water in the system. Corrosion inhibitors are used in certain areas and corrosion coupons are installed in lines and have shown very little to no corrosion.
- Have had shallow well integrity issues, due to non-EOR disposal activities, but have been remediated when they occur without any major impacts.

Expert Review Comments

Four external reviewers returned comments. The general consensus was that the report gives a good overview of challenges that may arise but the report was too extensive and required synthesising. Overall a majority of the changes following the review were relating to restructuring the report rather than editing content. The report has extensive appendices to synthesise the main content of the study. All comments were addressed in the final copy of the report.

Conclusions

In summary, industry experience (particularly with CO_2 EOR wells) for both CO_2 continuous injection as well as for CO_2-WAG, shows that new CO_2 storage injection wells can be suitably designed to allow well integrity to be maintained in the long-term, and concerns from long-term cement degradation and corrosion can be suitably addressed in the design and construction of these wells.

Well Integrity Challenges

- Analysis of injection and production data from the Norwegian sector shows that thermal cycling can affect wellbore integrity especially in injection wells. Casing design software such as WELLCAT^{TM} is widely used by most operators to ensure that the wellbore integrity is maintained throughout its life cycle.

- Proper maintenance of CO_2 injection wells is necessary to avoid loss of well integrity. Any annulus pressure build-up should be monitored and if Sustained Casing Pressure (SCP) is indicated, diagnostics should be performed and appropriate remedial steps taken to restore well integrity or the well shut-in, pending repair. Plugging and abandonment procedures are also important to ensure that the injected CO_2 will not escape or migrate out of the stored reservoir and/or saline aquifer.

- Both human factors and unforeseen reservoir conditions can contribute to the occurrence of blowouts and loss of well control. Safety procedures, in-depth personnel training and specialized equipment is used to minimize their likelihood. A full summary of case studies relating to loss of control wells is included in the report.

- The dynamic kill technique can be used to control a CO_2 blowout without the use of highly overbalanced kill fluids. This factor becomes important if flow restrictions, such as small diameter tubulars, limit fluid injection and rate.
- The use of corrosive resistant alloy (CRA) casings/liners etc. in lieu of carbon steel casing provide enhanced corrosion protection for severe CO_2 service but may have the downside of increased costs and with decreased injection capability. Due to the corrosive and highly solvent characteristics of supercritical liquid CO_2, special attention must be paid to rubber and plastic components such as packing and sealing elements.

Injectivity and Regulatory Challenges

- Initial industry concerns about CO_2 injection (especially during the WAG process) in terms of controlling the higher mobility gas: water-blocking, corrosion, production concerns, oil recovery, and loss of injectivity have been addressed with careful planning and design along with good management practices, except loss of injectivity, which is a key variable in determining the success of a CO_2 project.
- Numerical models are being successfully applied to adequately capture impacts of reservoir heterogeneity, multiphase flow behaviour and fluid-rock interactions on the pressure distribution in the subsurface. Still, more data from actual storage projects is needed to history match and verify model predictions and calibrate the models.
- Injectivity reduction after CO_2 WAG injection has occurred frequently in West Texas, as well in the Brent formations in the North Sea after hydrocarbon gas injection. Field data from a West Texas field suggests that reduced injectivity is an in-depth (far-field) phenomenon and not a near wellbore condition such as skin or high gas saturation around the injector.
- Numerical modelling studies have also shown the potential for well injectivity losses due to halite impairment in CO_2 storage wells. Studies suggest that a high CO_2 injection rate should allow the injection process to continue with limited impact on injectivity, even if significant halite precipitation takes place.
- Pressure build-up due to injection in both saline and depleted oil and gas reservoirs may be a potential challenge for some large-scale geological storage sites, therefore pressure-management strategies may need to be considered for some CCS projects. The use of water production (pressure relief) wells as proposed for the Gorgon project is one obvious solution, along with the use of horizontal wells.

Storage in Deep Saline Formations (DSFs) vs Oil and Gas (O&G) Reservoirs

- Oil and gas reservoirs are intersected by many wells, and stricter regulatory requirements may require operators to re-confirm the quality of zonal isolation, by recompleting or working over wells that will be exposed to CO_2.
- Uncertainty on capacity and injectivity is clearly lower for depleted reservoirs, giving them a net potential economic advantage, whereas the uncertainty on well containment favours saline formations, which are intersected by fewer wells.
- High injection pressures combined with low injection fluid temperatures can induce hydraulic fracturing which can affect the bounding seals (cap-rock and overburden). Depleted reservoirs have a lower risk from potential fracturing, since re-pressurization can be done up to a pressure that is lower than or equal to the original reservoir pressure.

Recommendations

The recommendations from this report are related to cement systems and zonal isolation for CO_2 injection wells. Extra care and attention has to be paid to the design and execution of cement jobs for both surface, intermediate and production casings. Most regulatory agencies mandate the surface casing to be cemented back to surface. Appendix 3 outlines the Standard Operating Procedures (SOPs) for CO_2 well design, construction and operation which can be taken as the recommendations from this report on how to handle CO_2 well engineering.

- Cement evaluation tools such as Ultrasonic Imaging Tool (USIT)/Segmented Bond Tool (SBT)/Isolation Scanner will need to be run to evaluate the quality of the cement bond to the casing and to the formation.
- The design of the cement slurry may use Portland cement as its base, provided efforts are taken to reduce the permeability of the set cement, reduce the concentration of available reactive species and/or protect those reactive species through use of carefully selected additives. Lower density system should use extenders that will allow permeability reduction which include flash systems, additives such as found in the tri-modal systems and specialty additives that protect the reactive species in Portland cement. The use of silicate extenders or only bentonite is not recommended.
- Portland cements used in oilfield applications have been found to provide adequate seal and zonal integrity in several CO_2 EOR projects (both continuous CO_2 flooding as well as water-alternating-gas/WAG applications). However, in some projects, it may be required to utilize CO_2 resistant and specialty cements to avoid degradation and corrosion impacts resulting from CO_2 injection into deep saline aquifers.
- Non-Portland systems that are resistant to CO_2 are commercially available though do require additional planning to assure proper design and prevention of contamination during the operations. These systems are not as readily available as conventional Portland systems, and thus may not be available in all areas. As noted the decision to use these systems is not trivial and requires considerable planning for logistics and operations.

WELL ENGINEERING AND INJECTION REGULARITY IN CO_2 STORAGE WELLS

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Executive Summary

Geologic storage/sequestration of carbon dioxide (CO_2) involves injection of large quantities of CO_2 into primarily deep saline aquifers for storage purposes or, where feasible, into oil and gas reservoirs for enhanced oil recovery (EOR) purposes. To successfully inject CO_2 into the subsurface, the CO_2 must be trapped in the subsurface and not be allowed to leak to the surface or to potable water sources above the injection horizon. The literature and experience from industrial analogs indicate that wellbores (active or inactive/abandoned) may represent the most likely route for leakage of injected CO_2 from the storage reservoirs. Therefore, sound injection well design and well integrity, operation and monitoring are of critical importance in such projects and this study attempts to address life-cycle well integrity risks from CO_2 injection wells.

The CO_2 EOR industry has extensive experience in developing materials of construction for well tubulars (casing/tubing/packer/seal-elastomers etc.) that are resistant to the corrosive effects of CO_2 both in the downhole and surface environments, and in the selection of corrosion- resistant cements to prevent cement degradation and loss of zonal isolation from CO_2 injection horizons. Existing pilot, demonstration and commercial storage projects have demonstrated that CO_2 geologic storage is technically feasible. In addition, handling and managing CO_2 operations safely are well established from the extensive experience gained from CO_2 EOR projects. It is important to clarify that the primary objective of CO_2 EOR operations is to increase the recovery of the Original Oil in Place (OOIP) from the reservoir and not to store CO_2. Therefore, the operating philosophy is different compared to pure CO_2 storage. In addition, these CO_2 EOR projects do not operate at a scale that is necessary to reduce greenhouse gas emissions significantly.

Although numerical models are being successfully applied to adequately capture impacts of reservoir heterogeneity, multiphase flow behavior and fluid-rock interactions on the pressure distribution in the subsurface, more data from actual storage projects is needed to history match and verify model predictions and calibrate the models (no history-matching comparisons have been made in this Report). Since reservoir quality information is particularly sparse for deep saline aquifers, resulting in large uncertainty in estimations of injectivity, sweep efficiency and storage capacity, it is critical to develop efficient and cost-effective injection strategies that maximize the injection rate and volume and decrease the required number of wells.

Well integrity issues impact well regularity (the ability to actually inject CO_2 regularly) at the desired rates necessary to store the delivered quantity or the quantity needed for CO_2 EOR purposes, with injection well regularity having an influence on the design and cost of storage facilities. For wells exposed to formations containing supercritical CO_2 it is important to identify the procedures and equipment that have to be tailored for the specific characteristics of CO_2 (as opposed to hydrocarbon gas, oil or water) and the specific equipment and procedures may cover drilling, completion, operation, interventions and abandonment. Compliance with local regulatory requirements will also affect the design and cost of the storage facilities.

In-depth case studies with a focus on industry experience with wellbores that are used for the production or injection of CO_2 have been presented in this Study and represent different operating settings: onshore CO_2 EOR, offshore CO_2 EOR and CO_2 storage projects located in the Permian Basin, Texas as well as offshore North Sea, Brazil and other locations in the world. One of the case studies included a facility visit and meeting with an active CO_2 EOR operator located in Midwestern U.S. in Michigan (see Section 8.6, Case Study # 6 – Core Energy). Other CO_2 EOR operators with active operations in West Texas declined to participate in this Study (perhaps due to regulatory or legal concerns).

Blowouts experienced during gas injection (both for CO_2 and other gases) and their main causes, prevention, and implications for CO_2 storage are also included in this Study. This will provide more data to assure public stakeholders that in spite of CO_2's unique characteristics, CO_2 injection and production operations can be handled and managed safely, without endangering human health and safety and the environment.

The Report includes a current state-of-the-art Standard Operating Practices to enable operators to safely operate CO_2 injection wells for both EOR as well as storage operations. The existing regulatory structure (Texas Railroad Commission and EPA in the U.S. and the Alberta Energy Regulator in Canada) for both CO_2 EOR injection/production wells and CO_2 storage injection wells and an overview of regulations and regulatory jurisdictions for CO_2 geologic storage operations in the United Kingdom, European Union, Brazil and Australia are also included in the Report (See Section 7.0).

The cost implications for designing a CO_2 injection well as compared to a conventional oil and gas production or injection well are discussed along with the associated costs related to modifications required for CO_2 injection operations (See Section 2.1.10). There are significant differences between the costs and logistics of onshore and offshore CO_2 injection and can affect the viability of a CO_2 injection project, and these differences apply worldwide.

An extensive listing of References applicable to well design, construction, operation and management of CO_2 injection wells (with an emphasis on well construction and wellbore integrity) for both CO_2 EOR wells and CO_2 storage wells is included in the Report and covers both onshore and offshore areas.

The common areas and differences between CO_2 EOR and CO_2 storage wells have been presented in the Report (See Section 5.0). Table 8 gives a comparative summary of conventional oil and gas injection wells and CO_2 EOR and CO_2 storage injection wells (with emphasis on onshore operations). However, there are no specific technological barriers or challenges per se in converting or adapting a pure CO_2 EOR operation into a concurrent or exclusive CO_2 storage operation.

In summary, industry experience particularly with CO_2 EOR wells (both for CO_2 continuous injection as well as for CO_2 WAG - water-alternating-gas) shows that new CO_2 injection wells can be suitably designed to allow well integrity to be maintained in the long-term, and concerns from cement degradation and corrosion can be suitably addressed in the design and construction of these wells. Industry experience also indicates that CO_2 storage injection wells can also maintain wellbore integrity if designed, constructed, operated and monitored as per current state-of-the-art design specifications and regulatory requirements. Risks from legacy wellbores can also be adequately addressed as long as sound engineering practices and compliance with current and more stringent regulatory requirements are complied with.

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Nomenclature

AOR – Area of Review
AP – annular pressure
API – American Petroleum Institute
AER – Alberta Energy Regulator
BCF – billion (10^9) cubic feet of gas at standard conditions
BCFD – billion cubic feet of gas at standard conditions
Bbl – barrel
Bar – 14.504 psi
BOP – blow out preventer

BOPD – barrels of oil per day
^0C – temperature, Celsius
$CaCO_3$ - calcium carbonate
$Ca(HCO_3)_2$ – calcium bicarbonate
$Ca(OH)_2$ – calcium hydroxide
CO_2 EOR – carbon dioxide enhanced oil recovery
CO_2 GS – carbon dioxide geologic storage
CCS – carbon capture and storage
CRA – corrosion resistant alloy
CSH – calcium silicate hydrate
DHSV – downhole safety valve
EOR – enhanced oil recovery
^0F – temperature, Fahrenheit
ERCB – Energy Resources Conservation Board
GHG – greenhouse gas
HCO_3^- - bicarbonate ion
H_2CO_3 – carbonic acid
H_2S – hydrogen sulfide
HCl – hydrochloric acid
IEAGHG – International Energy Agency Greenhouse Gas Programme
IPCC – International Panel on Climate Control
ISO – International Standards Organization
Kilopascal (KPa) – 0.145 psi
Kt – thousand (10^3) metric tons/tonnes
LWC – loss of well control
Megapascal (MPa) – 145.03 psi
MCF – thousand (10^3) cubic feet of gas at standard conditions
MMCF – million (10^6) cubic feet of gas at standard conditions
MAWOP – maximum allowable wellhead operating pressure
MIC – microbial induced corrosion
MIT – mechanical integrity test
MMP – minimum miscibility pressure
Mt – million (10^6) metric tons/tonnes
NACE – national association of corrosion engineers
OGJ – Oil and Gas Journal
OOIP – original oil in place
PHMSA – pipeline and hazardous materials safety administration (US)
ppm – parts per million
PSA – Norway's Petroleum Safety Authority
psia – pressure, pounds per square inch absolute
psig – pressure, pounds per square inch gauge
ROZ – residual oil zone
RP – recommended practice
RRC – Texas Railroad Commission
SACROC – scurry area canyon reef operators committee
SCP – sustained casing pressure
SOP – standard operating practices
SO_4^{-2} – sulfate ion
SSV – subsurface sliding sleeve valve
TAP – trapped annular pressure
TP – thermal pressure
TCF – trillion (10^{12}) cubic feet of gas at standard conditions
TCFD – trillion cubic feet of gas at standard conditions per day
USEPA – United States Environmental Protection Agency

WAG – water-alternating-gas
WIMS – well integrity management systems
WMI – well mechanical integrity

<u>Standard Conditions:</u>
Pressure 14.65 psia
Temperature 60^0 F

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The authors would like to thank James Craig and Lydia Rycroft (IEA GHG) for their support, advice and patience throughout the preparation of this Report. We also thank the external reviewers for their comments and suggestions which has greatly improved the final version of the Report. We are grateful to Core Energy, LLC for hosting us and allowing us to conduct a field visit to their CO_2 EOR facilities in Michigan, U.S.A and for their input in the preparation of this Report.

We would also like to acknowledge Dr. Neeraj Gupta and Battelle for their help providing materials for the case study on CO_2 Injection in the Midwestern U.S. and for an introductory letter that facilitated our field visit to Core Energy's CO_2 EOR operations in Michigan.

It is also with great sadness, that we announce the passing away of our friend and colleague Mr. Ronald Sweatman and a co-author of this Report in Houston, TX on March 30, 2018, after a distinguished 55-year career in the oil and gas industry.

WELL ENGINEERING AND INJECTION REGULARITY IN CO_2 STORAGE WELLS

1.0 INTRODUCTION

Geologic storage/sequestration of carbon dioxide (CO_2) involves injection of large quantities of CO_2 (to meet climate and greenhouse gas emission targets) into primarily deep saline aquifers for storage purposes or, where feasible, into oil and gas reservoirs for enhanced oil recovery objectives. To successfully inject CO_2 into the subsurface, the CO_2 must be trapped in the subsurface and not be allowed to leak to the surface or to potable water sources above the injection horizon. The literature and experience from industrial analogs indicates that wellbores (active or inactive/abandoned) may represent the most likely route for leakage of injected CO_2 from the storage reservoirs. To avoid leakage from injection wells, the integrity of the wells must be maintained during the injection period and for as long as free CO_2 exists in the injection horizon. In addition to injection wells, monitoring wells will most likely be required to observe the plume movement and possible leakage.

In addition to the new injection and monitoring wells, the saline aquifers that are attractive storage sites for CO_2, may often be located in areas where oil production and a large number of wells exist (for example in the province of Alberta, Canada alone, there already exists more than 350,000 wells and around 15,000 wells are drilled each year (AER/ERCB, 2009 in Nygaard, 2010). The integrity of existing wells that penetrate the capping formation also needs to be addressed to avoid CO_2 leakage (Nygaard, 2010). Therefore sound injection well design and well integrity, operation and monitoring are of critical importance in such projects.

CO_2 injection for enhanced oil recovery (CO_2 EOR) has a well- established history in the United States, Canada and elsewhere. The knowledge of how to manage pure CO_2 operations exists in areas such as the USA (with significant experience) and Eastern Europe (with perhaps lesser experience than the US) where some operators produce pure CO_2 from natural accumulations for EOR applications. In the United States alone, the oil and gas industry has injected over 600 Mt (million tons) of CO_2 (11 trillion standard cubic feet) over the past 35 years (Contek/API, 2008) and the CO_2 is believed to be stable once injected, provided the original pressure of the geological formation is not exceeded. CO_2 EOR projects, along with wells drilled in H_2S-rich environments and high-temperature geothermal projects, have delivered developments for improved well designs and materials, such as improved tubulars and cements. It is also evident that valuable lessons can be learned from hydrocarbon exploration, natural gas storage and CO_2 blowouts.

The study's primary objectives are: (1) to gather well engineering and intervention experience from active CO_2 injection projects and from pure CO_2 production operators on the drilling, completion, regularity (the ability to actually inject CO_2 regularly) and interventions of CO_2 wells; and (2) to compare CO_2 EOR with CO_2 storage operations and summarize the best practices on CO_2 operations. A secondary objective was to investigate whether conditions experienced during CO_2 handling operations were predicted from modelling and experimental work and the effectiveness of linked risk assessments. Injection regulations are not a focus of this report but have been included where relevant.

Well integrity issues impact well regularity (the ability to actually inject CO_2 at the desired rates necessary to store the delivered quantity or the quantity needed for CO_2 EOR purposes or storage purposes) and the design and cost of storage facilities. Experience from CO_2 pilot storage sites has revealed complex interactions between wellbore and formations. Existing knowledge and experiences with CO_2 injection wells have been reviewed and include some recommendations for improvements to models of CO_2 properties in injection wellbores.

The target audience for this report will be operators (with IEAGHG members including Shell, Statoil, Total and ExxonMobil) with the intention that the report will be utilized by potential future CCS operators. This report will also benefit developers and regulators who may be unfamiliar with CO_2 injection wells and CO_2 handling operations.

The Study has selected and presented a series of six case studies which include the Denver Unit of the Wasson Field, Permian Basin, Texas; Uthmaniyah, Saudi Arabia; and the Petrobras Lula site in offshore Brazil. For onshore case studies, the focus of the Report was on CO_2 EOR operations in the U.S., since the majority of the CO_2 EOR projects are located in the U.S. and many of the CO_2 regulations have been developed, enforced, and periodically updated for several decades. It is hoped that the case studies can provide insights into the following important areas (although it may not specifically answer some or all of the following bullet points):

- *What are the differences in equipment and procedures for drilling rigs, workover rigs, and coiled tubing/wireline units for onshore and offshore when comparing work on pure CO_2 wells with hydrocarbon wells*
- *What are the key differences between CO_2 and hydrocarbons that influence safety and risk assessments for well operations*
- *During wellbore maintenance operations did any events occur that were not predicted or were most accounted for within the risk assessment*
- *During wellbore operation (production/injection) did any events occur that were not predicted or were most accounted for within the risk assessment*
- *For all well operating environments, it is important to be able to rapidly deploy drilling rigs if an uncontrolled release takes place. Is there a minimum check list that should be in place to ensure that there will always be rigs available to deploy – onshore, like in the Permian Basin, USA, and offshore*
- *How were long-term wellbore integrity assessments conducted? Fundamentally, was wellbore design modified to meet new specifications for CO_2 storage and were different remediation measures put in place*
- *What new techniques were undertaken to ensure integrity of the wellbore (how was the monitoring and verification plan different to a conventional site)*
- *Were any differences noted between predicted degradation of the wellbore and any observations during or post CO_2 injection/production*
- *How did near-wellbore conditions influence CO_2 injection operations*
- *Was injection regularity maintained and did well integrity have any impact on achieving planned regularity*

- *What have been the long-term implications for cement degradation? Has there been any evidence of corrosion? Did wellbore integrity remain intact?*

- *What were the financial implications for the modifications required for CO_2 injection and storage development?*

- *What are the cost implications of designing a wellbore for CO_2 injection/production? How does this compare with wells for hydrocarbon production?*

An extensive literature review was performed to assess current best operator practices for CO_2 EOR and CO_2 storage wells and to cover the key risks and uncertainties of CO_2 injection wells and CO_2 handling operations. Areas covered including casing and completion design for CO_2 injection and production wells, cementing design and implementation applicable to CO_2 injection and production wells, corrosion control and material selection for maintaining well integrity of both tubulars and cement materials that come in contact with supercritical CO_2. Well control and kick detection and potential blowout concerns working with CO_2 wells are also included in the Report. The Report includes a current state-of-the-art Standard Operating Procedures (SOPS) to enable operators to safely operate CO_2 injection wells (See Appendix 3).

One of the key objectives of this Report was to supplement the literature review with direct communication with major operators who have first-hand experience of handling CO_2 at well-sites and benefit from their operational experience. Regretfully, several of the operators in the CO_2 EOR industry in the U.S. (with the exception of Core Energy, LLC) declined to participate in this Study (due to legal and/or regulatory concerns). We are grateful to the participation of Core Energy (a CO_2 EOR operator in Michigan) and input received from this operator has been included in the Report. The Denver Unit, Wasson Field, Permian Basin Case Study was prepared from data that was available from public records.

The geological storage of CO_2 is a complex process that depends on in-situ geological, hydrodynamic, geochemical, geothermal and geomechanical conditions. Numerical modeling is a means of using these conditions to understand and predict the fate, transport and potential impacts of the injected CO_2 and associated pressure increases. Modeling is heavily influenced by the quantity and quality of the defining attributes of the system and its associated data. The more limited the data set, the greater the uncertainty in predicted model outcomes.

The level of uncertainty in model predictions is reduced by history matching of either laboratory experiments or field pilots. During the characterization phase of a storage project, when the data are variable and of limited quantity, modeling of the storage site will be very valuable in providing a sufficient technical basis and sensitivity analysis for risk management of the system. During development and subsequent commercial storage operations, these models can be further refined with new data to provide greater confidence in the predicted outcomes. Please see Section 5.4 – Reservoir Modelling and Appendix 3 of this Report – SOPS - Well Planning – Modeling for characterization for a further discussion.

2.0 WELL DESIGN STANDARDS AND RECOMMENDED PRACTICES

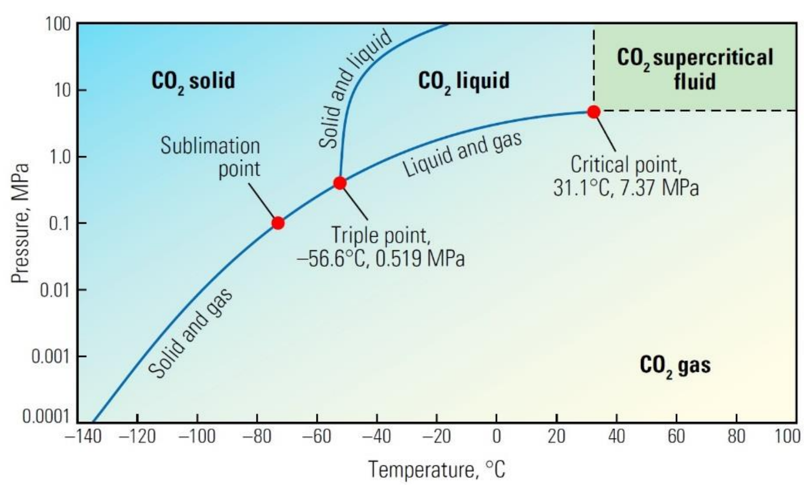
Oil and gas wells have existed for more than 150 years, since the first well was drilled in 1859 (Drake's well in Pennsylvania). As well technology has evolved over the decades, trade, professional and government organizations such as the American Petroleum Institute (API), the American Society of Mechanical Engineers, the National Association of Corrosion Engineers (NACE), International Organization for Standardization (ISO), NORSOK to name a few, have and continue to evaluate and publish the technical requirements and associated best design and operational practices into formal engineering standards and recommended practices. Supplementing these documents is the design experience of a large number of operators and their professional staff. See Appendix 3 for Standard Operating Practices for Designing, Constructing, and Operating CO_2 Injection Wells and Appendix 4 for Listing of Applicable Standards and Guidelines for Well Construction, Well Operations and Well Integrity.

2.1 WELL DESIGN FOR CO_2 INJECTION WELLS

2.1.1 Properties of CO_2

Carbon dioxide, a molecule that consists of two oxygen atoms covalently bonded to a single carbon atom, has a molecular weight of 44 g/mol. Depending on temperature and pressure, CO_2 can exist as a solid, liquid, or gas.

Figure 1 – CO_2 Phase Behavior (Oilfield Review September 2015)



Carbon dioxide phases (see Figure 1) – Phase boundary lines (blue) define the areas in which each CO_2 phase exists. At the triple point, all three phases – solid, liquid and gaseous CO_2 – coexist in thermodynamic equilibrium. Along the solid-gas line below the triple point, CO_2 sublimes – converts directly – from a solid to a gas without going through a liquid phase. The marked sublimation point corresponds to 0.101 MPa (14.7 psi) of CO_2 vapor. Along the solid-liquid line above the triple point, solid CO_2 melts to a liquid. Along the liquid-gas line above the triple point, liquid CO_2 evaporates to a gas. At the critical point, the liquid and gaseous states of CO_2 are indistinguishable, and phase boundaries no longer exist. These attributes at the critical point and at higher temperature and pressure characterize the area in which CO_2 is a supercritical fluid (green) (Oilfield Review, 2015).

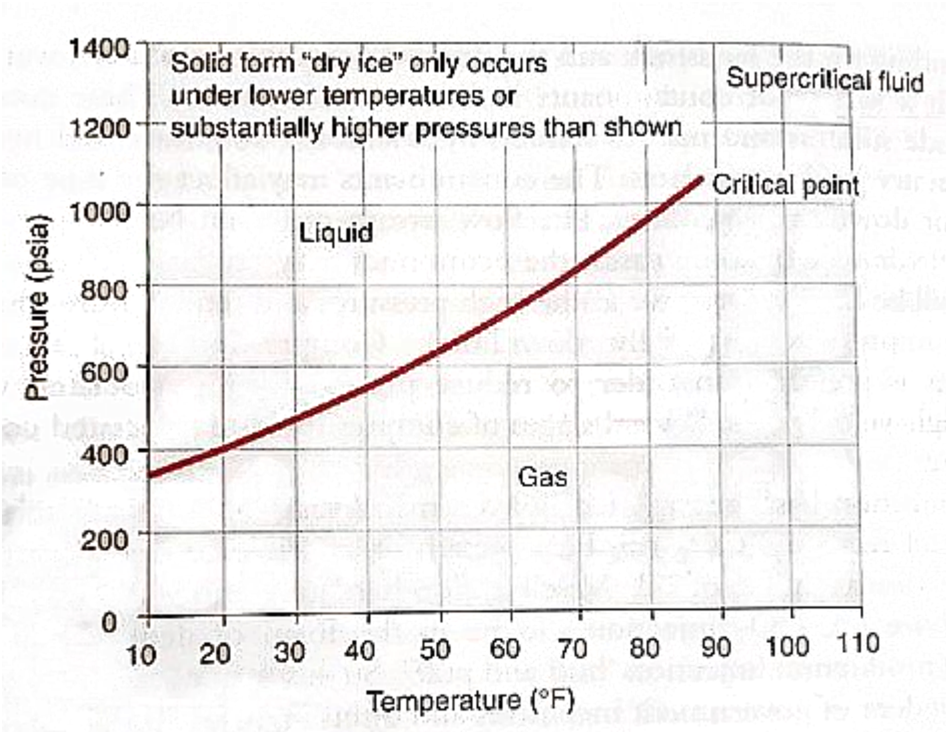
The solvent characteristics of supercritical CO_2 are well known. As a solvent, supercritical CO_2 is miscible with many crude oils, reducing its viscosity and surface tension, thereby allowing for easier displacement of residual crude oil that would not otherwise be recovered. At higher than critical pressures and temperatures, CO_2 is in the supercritical state and forms a phase whose density is close to that of a liquid, even though its viscosity remains quite low (0.05 – 0.08 centipoise). This dense phase can extract hydrocarbon components more easily than gaseous CO_2. Very shallow reservoirs may not benefit from CO_2 EOR because the low pressures can preclude the use of supercritical CO_2, reducing sweep efficiency. CO_2 is normally transported as a liquid for economic and operational considerations.

Generally, storage formations are targeted for depths of 800 meters (2,625 feet) or deeper because at these depths the CO_2 is more like a liquid than a gas so it is denser and requires less pore space. Storage could occur at shallower depths if there is a suitable porous reservoir with an effective "trapping" layer (caprock) immediately above it. However, most storage projects will target storage sites deeper than about 1 km (0.621 mile), and some regulations are in place (Alberta, Canada) that state that storage must be at a depth > 1 km (0.621 mile). Also, the presence of shale layers (called aquitards) above the caprock is beneficial, since they would restrict the flow of fluids and act as a seal (Hitchon, 2012).

Due to its weakly bi-polar nature, CO_2 is highly soluble in water, with which it reacts to form carbonic acid. CO_2-related corrosion is generally attributed to carbonic acid. Only a small fraction of the total CO_2 volume dissolved in water reacts. The remainder of the gas remains in solution to supply a continuous CO_2 source. The corrosion is localized, likely the result of small galvanic cells formed in specific areas. Other chemical reactions can also create scales that protect one area, while a nearby area is exposed to the acid. Many reservoirs in which CO_2 is injected also produce corrosive H_2S and high chloride waters.

Under most reservoir conditions, CO_2 does not behave like a gas, but more like a low viscosity liquid. This will affect the injection performance (in the tubing and near wellbore area). The CO_2 will commonly be supercritical under downhole conditions as shown in Figure 2. Except at very high pressures, CO_2 is lighter than most oils, but it is denser than hydrocarbon gases such as methane. It will therefore naturally migrate to the top of oil and water bearing structures. This is important as this CO_2 will then potentially interact with wells and completions at the top of the reservoir.

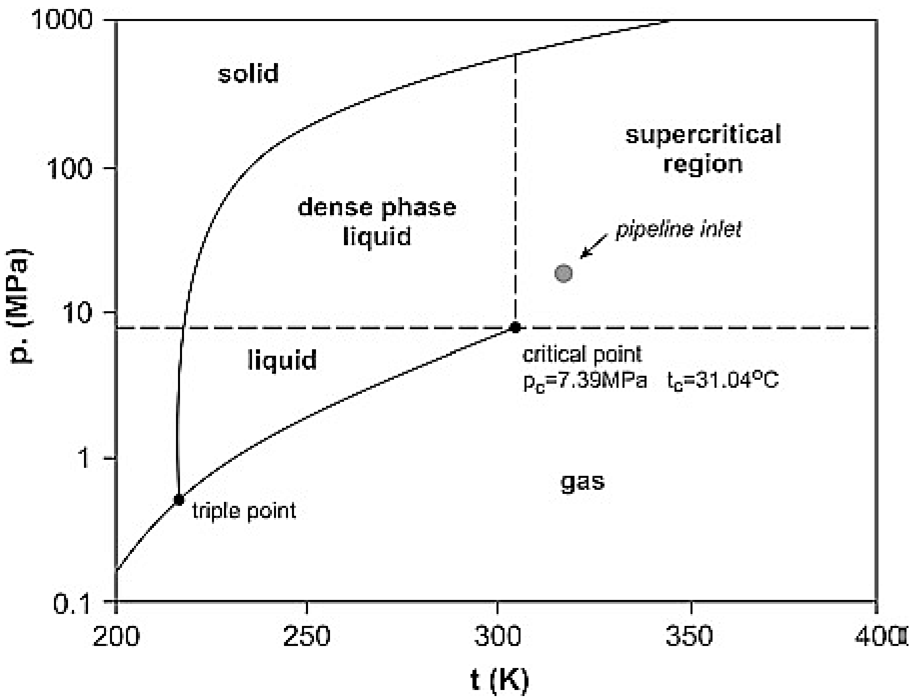
Figure 2 - CO_2 Phase Envelope (Bellarby, 2009)



<u>*Importance of CO_2 Phases*</u>

Piping in CO_2 distribution systems must be designed taking CO_2 phase changes into account because the frictional pressure drop of dense phase CO_2 (which behaves more like a liquid) exceeds that of supercritical CO_2, which behaves more like a gas (Figure 3). Dense-phase CO_2 can generate much larger hydrostatic pressures than supercritical CO_2. This occurs as dense phase CO_2 is present at a lower temperature (below 31.04^0 C) than supercritical CO_2, thus has a higher density than supercritical CO_2. *Dense phase* is a fourth phase (Solid, Liquid, Gas, Dense) that cannot be described by the senses. The dense phase has a viscosity similar to that of a gas, but a density closer to that of a liquid. Because of its unique properties, dense phase has become attractive for transportation of CO_2 and natural gas, EOR, food processing and pharmaceutical processing. An added benefit of transporting CO_2 in the dense phase is the absence of liquids formation in the pipeline (www.jmcampbell.com/tip-of-the-month/2012/01/transportation of co2-in-dense-phase/) and Witkowski et al., 2015.

Figure 3 – CO_2 Phase Behavior (Pipeline), Witkowski et al, 2015



Phase changes within a CO_2 distribution system are even more troublesome. A two-phase mixture of liquid-like and gas-like CO_2 generates a larger frictional pressure drop than either phase alone. Because of the complexities of phase behavior and the number of alternative arrangements for piping, a pipeline simulator model generally is used to design the CO_2 distribution system. Because heat transfer and pressure changes can cause CO_2 to change phase, the simulator package should include a thermodynamic package to account for heat losses through the tubing.

Overall, the advantages of CO_2 injection outweigh the disadvantages. Although CO_2 is a greenhouse gas and venting should be minimized, large scale releases to the atmosphere normally do not occur because produced CO_2 is reinjected into the reservoir for enhanced oil recovery or into a saline aquifer for long-term storage. Due to the unique characteristics of CO_2, the preparation and implementation of a written environmental, health and safety (EHS) plan is a pre-requisite prior to initiation of any CO_2 injection project (See Appendix A7.4).

2.1.2 Casing Design

As is required in all engineering designs, surface equipment and downhole tubulars are designed for the anticipated operating pressures. This design requirement results in the proper selection of appropriate casing and tubing grade and weight to avoid wellbore collapse. There is a higher risk of compromising the casing integrity during drilling operations. The following points should be considered in casing design (NORSOK 2004):

- *Planned well trajectory and bending stresses induced by doglegs and curvature*
- *Maximum allowable setting depth with regards to kick margin*
- *Estimated pore pressure development*
- *Estimated formation strength*
- *Estimated temperature gradient*
- *Drilling fluids and cement program*
- *Estimated casing wear*
- *Setting depth restrictions due to formation evaluation requirements*
- *Isolation of weak formations, potential loss circulation zones, sloughing and caving*
- *Metallurgical considerations*
- *Potential for H_2S and CO_2*
- *Equivalent circulating density (ECD) and surge/swab effects due to narrow clearances*
- *Geo-tectonic forces applicable*

The casing is exposed to different loading conditions during various well operations (landing, cementing, drilling, production). It has to be designed to withstand tensile, burst, and collapse loads. Since it is difficult to accurately predict the magnitude of these loads during the life of the casing, the design is based on a worst-case scenario. The casing also deteriorates with time (wear and tear). Therefore, safety factors are used to make sure that the casing could withstand expected loading conditions.

Collapse pressure is mainly due to the fluid pressure outside the casing (due to drilling fluid or cement slurry). Overpressure zones could also subject the casing to high collapse pressure. Depletion of over-pressured, under-compacted reservoirs can result in a large pore pressure drop and sediment compaction, and may result in casing deformation in the vicinity of such reservoirs. Finite element analysis modeling can be used to predict the various casing loads involved during the depletion (Bradley et al, 1989). It should be noted that CO_2 injection and storage facilities will not be selected if the depleted oil and gas reservoirs are over-pressured (for example in natural gas storage reservoirs where a delta pressure (Δp) is added to increase storage capacity, Cooper, C, 2009) or have the potential for fault reactivation. The casing's critical collapse strength is a function of its length, diameter, wall thickness, Poisson's Ratio etc. Burst loading on the other hand is due to the fluid pressure inside the casing. Severe burst pressure occurs if there is a kick during drilling operations. The tensile stress on the other hand originates from pipe weight, bending load and shock load. The axial force due to pipe weight is its weight in air less the buoyancy force. Bending force results when the casing is run in deviated wells where the upper portion of the casing is in tension whereas the lower portion is in compression. Shock load on the other hand is generated by setting the slips and application of hoisting brakes. The sudden stoppage when casing is run generates stress waves along the casing string (Syed, 2010).

In addition to the three loading conditions described above, casing design should also consider the likelihood of buckling, piston and thermal effects. Buckling results when the casing is unstable (e.g. partially cemented). The casing string will exhibit a helical configuration below the neutral point, resulting in rapid wear at the neutral point and eventually lead to casing failure. Piston force is due to the hydrostatic pressure acting on the internal and external shoulders of the casing string while thermal effects refer to the expansion or shortening of the casing due to increase or decrease in temperature (SINTEF, 2007).

Production of relatively hot reservoir fluids, injection of hot fluids and relatively cold drilling and stimulation fluids create mechanical and thermal stresses in the casing/cement/rock system (Wu et al., 2008, Wong et al, 2000, Charara et al., 1992). If sufficiently high, these stresses may damage the annular cement and contribute to debonding along the casing/cement or cement/rock interfaces, or induce radial thermal fractures in the near-well area. This may jeopardize the integrity of the near-well area, with eventual leakage along the well as a result (Lavrov et al., 2014). A complex interplay of coupled multi physics multiscale processes affects wellbore integrity. These include elastic and plastic deformation of the rock; hardening and shrinkage of the cement; thermal stresses in and deformations of casing, cement sheath and rock; poro-elastic effects; and time-dependent deformation (Gray et al., 2007 and Dusseault et al., 2001). Since it is generally difficult to access and assess downhole conditions, laboratory and numerical models have been developed to gain an insight into downhole casing, cement and near-wellbore conditions during a well's operating life cycle (Lavrov et al., 2014 and Musso et al., 2010).

The casing material selection strategy is to avoid having the casing come into contact with wet CO_2. To prevent CO_2 from coming in contact with the casing, completion tubulars, chemical inhibitors in the completion fluid used to fill the annular space, and cement outside the casing will be used as barriers. Material selection for CO_2 corrosion control and cementing design for CO_2 injection wells are presented in Sections 4.3, 4.4 and Appendix 5 - Cementing of this Report.

State-of-Art Casing Design Software

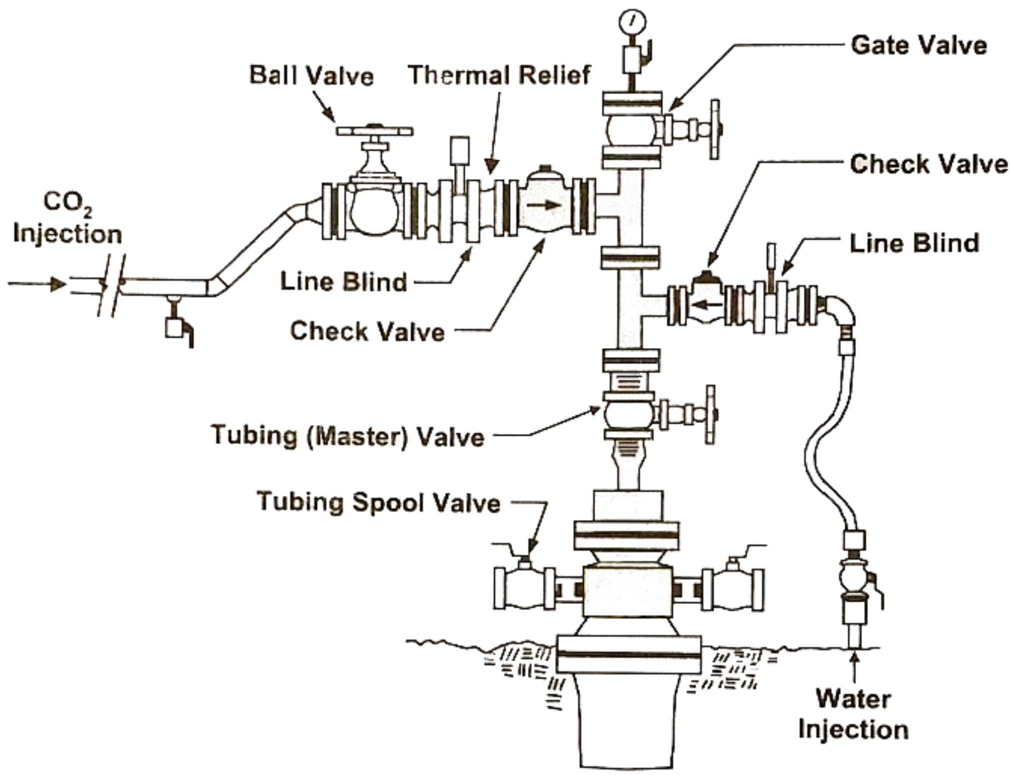
Drilling in environments such as: high pressure/high temperature – HP/HT, deep/ultra-deep, steam-assisted gravity drainage (SAGD), extended reach (ERD and ultra-ERD), arctic, shale gas/oil, hydraulic fracturing, salt zone drilling and CO_2 injection results in complex loading conditions on the casing/tubular/cement etc.

The most widely used industry software today is WELLCAT™ (Halliburton/Landmark) with several integrated modules: (1) Casing Design applications include: comprehensive casing design and analysis; installation and service loads; buckling stability and post-buckling analysis, with and without centralizers; and connection strength envelope safety factors; (2) Tubing Design applications include: comprehensive tubing design and analysis; installation and service loads; mechanically, hydrostatically and hydraulically setting mechanisms; packer setting sequence; tubing movement, dual completions; multiple packer completion configurations, CRA (corrosion and erosion resistant alloy) tubular, and yield anisotropy, and packer envelope load check; (3) Drill Design module simulates flow and heat transfer during drilling operations; (4)Prod Design module simulates fluid and heat transfer during completion, production, stimulation, testing and well-servicing operations; and (5) Multistring Design module predicts pressure and volume changes caused by trapped annular pressure when well system heats up due to production or injection of hot fluids. It determines the movement that occurs to the wellhead during the life of the well. WELLCAT™ software by combining drilling and production thermal flow simulator modules, casing and tubing stress analysis modules, and multistring load analysis modules allows the simulation of the entire well history of events from drilling and production operations (www.landmark.com/solutions/WELLCAT).

2.1.3 Wellhead Design

Although the design of a CO_2 EOR injection well is similar to that of a water injection well and most downhole equipment is virtually the same, the wellhead for a CO_2 EOR injection well differs significantly from that of a water injection well. A typical wellhead configuration for a CO_2 EOR WAG (water alternating gas) well is shown in Figure 4.

Figure 4- CO_2 WAG Injection Wellhead (Jarrell et al, 2002)



2.1.4 Wellbore Design

Depending upon circumstances, CO_2 EOR injection wells may be either drilled as new wells or, as is quite common in existing fields, re-completed by converting an existing producing well or a water injection well to a CO_2 injector. A CO_2 storage well is in most cases similar to a CO_2 EOR injection well, however, in some instances the design requirements for a CO_2 storage well may be more stringent, depending upon a case-by-case basis (Parker et al, 2009).

All wells have two basic elements: the wellbore, which includes the casings, cement and casing-heads, and the completion which includes the packer, tubing and wellhead valves assembly. The oil and gas industry has developed many standards for well equipment design that are routinely used in CO_2 EOR operations (Contek/API, 2008).

An example wellbore design for a new CO_2 EOR injection well is presented in Figure 5 and the wellbore schematic for a CO_2 Class VI storage well (permit issued by EPA) in Figure 6. As expected, the well designs are similar in both cases, consisting of: surface casing and production casing. Multiple casing strings are used for a variety of reasons, the principle of which is isolation of groundwater resources from potential sources of contamination and maintaining the integrity of the wellbore from collapse.

Mechanically, casing string specifications, i.e. their thickness and weight, are based on maximum potential burst and collapse pressures plus appropriate safety factors, which are a function of injection and production pressures, well depth, and reservoir conditions. For wells 10,000 feet (3,048 m) or less in depth, carbon steel casing is typically used with J-55 and K-55 grades being common. In deep, HPHT environments, higher strength grades may be used and corrosion resistant alloys (CRA) are used in wells susceptible to H_2S and CO_2 attack (See Section 4.3).

Figure 5 - Typical CO_2 EOR Injection Well Schematic, Permian Basin (Contek/API, 2008)

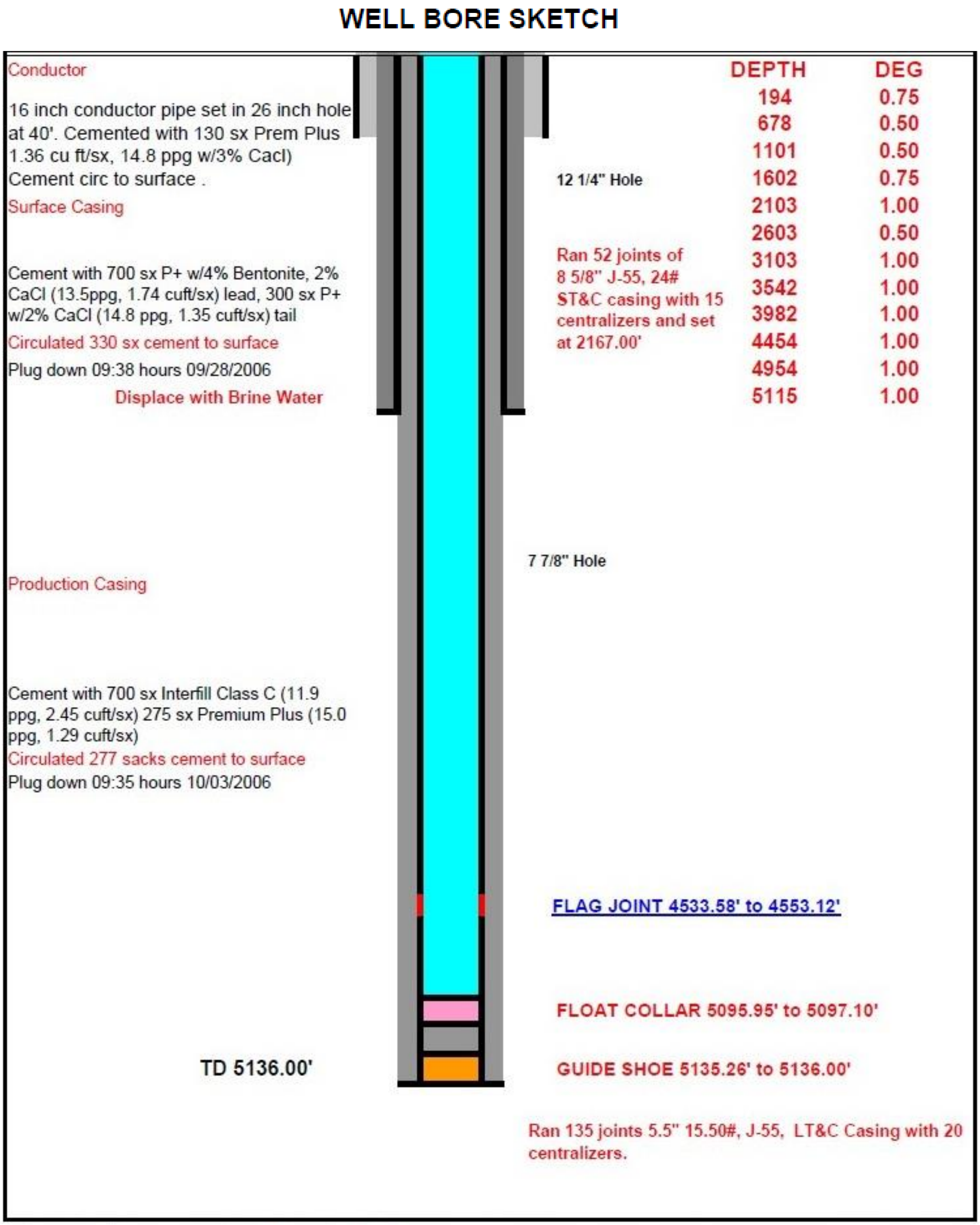
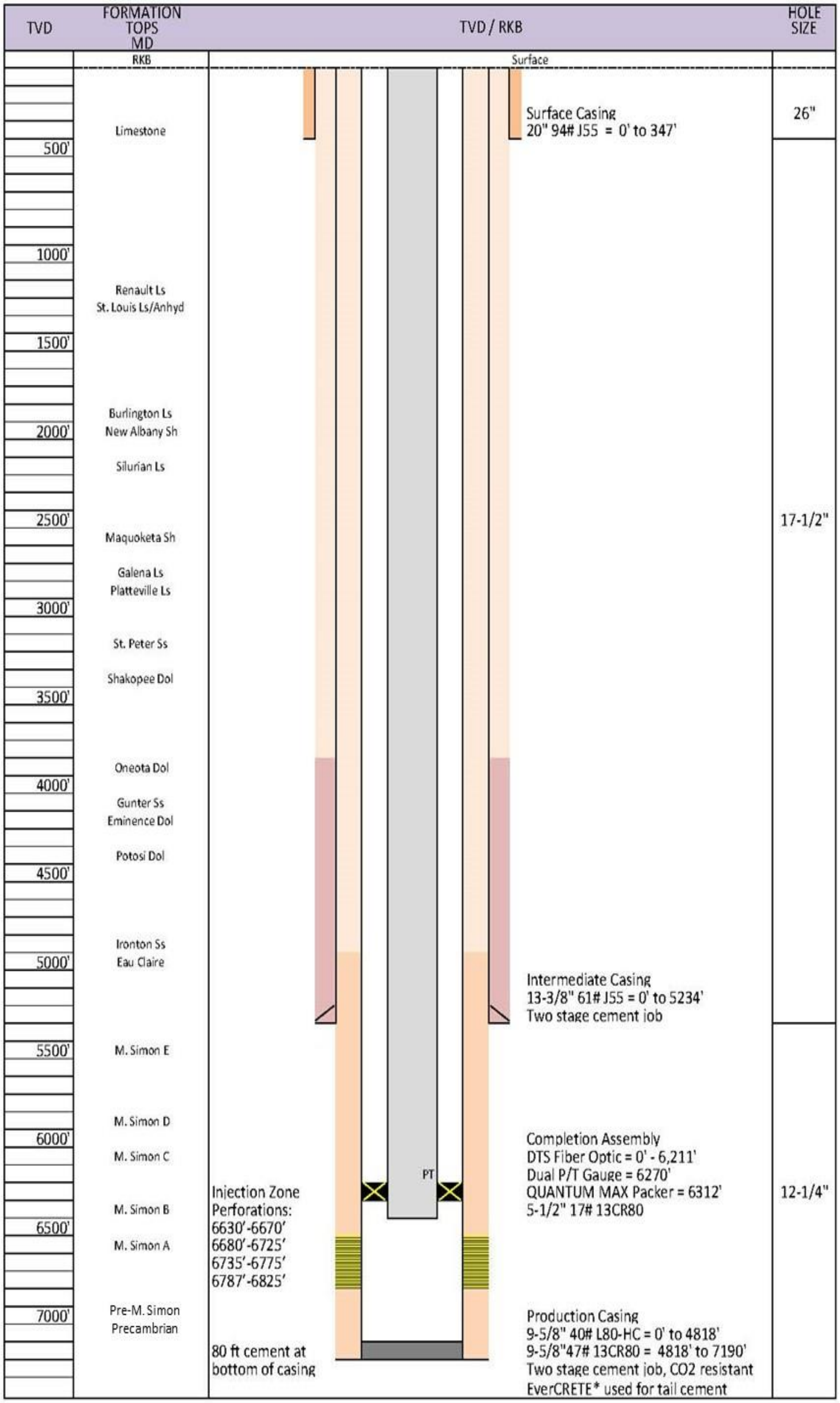


Figure 6 - ADM CCS # 2 Class VI-GS Well, Decatur, Illinois, U.S.A. (As built well construction schematic)



Well construction details for the ADM CCS # 2 CO_2 Storage Well (Class VI) (https://www.epa.gov/uic/archer-daniels-midland-final-modified-permit-attachments, Attachment G – EPA Region 5, Class VI Permit No. IL-115-6A-0001, January 19, 2017) are given below:

ADM CCS # 2 Well

Location: Decatur, Macon County, IL; 390 53 09.32835", -880 53' 16.68306"

Open hole diameters and intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Surface	0 - 347	26	To bedrock
Intermediate	347- 5,234	17 ½	To primary seal
Long	5,234 - 7,190	12 ¼	To Total Depth

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77 ° F (BTU/ft.hr.°F)
Surface[1]	0 -347	20	19.124	94	J55	Short	31
Intermediate[2]	0 -5,234	13 3/8	12.515	61	J55	Long or Buttress	31
Long[3] (carbon)	0 - 4,818	9 5/8	8.835	40.0	L80-HC	Long or Buttress	31
Long[3](chrome)	4,818 - 7,190	9 5/8	8.681	47.0	13CR80	Special	16

Note 1: Surface casing is 347 feet of 20 inch casing. After drilling a 26 inch hole to 347 feet true vertical depth (TVD), 20 inch, 94 pounds per foot (ppf), J55, short thread and coupling (STC) casing was set and cemented to surface. Coupling outside diameter is ~21 inches.

Note 2: Intermediate casing: 5,234 feet of 13 3/8 inch casing. After a shoe test or formation integrity test (FIT) was performed, a 17 ½ inch hole was drilled to 5,234 feet TVD. 13-3/8 inch, 61 ppf, J55, long thread and coupling (LTC) or buttress thread and coupling (BTC) was cemented to surface. Coupling outside diameter is ~14 3/8 inches.

Note 3: Long string casing: 0-4,818 feet of 9 ⅝ inch, L80 -HC casing; 4,818' – 7,190' of 9 ⅝ inch, 13CR80. After a shoe test was performed and the integrity of the casing was tested, a 12 ¼" hole was drilled to 7190' TVD or through the Mt. Simon, where the long string casing was run and specially cemented. Coupling outside diameter is 10 ⅝ inches for L80 -HC and 10.485 inches for the 13CR80.

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing[1,2,3]	0-6,350	5 ½	3.963	17	13CR80	Special	8,960	7,820

Note 1: Maximum allowable suspended weight based on joint strength of injection tubing. Specified yield strength (weakest point) on tubular and connection is 306,000 lbs.

Note 2: Weight of injection tubing string (axial load) in air (dead weight) is 88,200 lbs.

Note 3: Thermal conductivity of tubing @ 77°F is 16 BTU / ft.hr.°F.

The injection well has approximately 80 feet of cement above the casing shoe to prevent the injection fluid from coming in contact with the Precambrian granite basement.

2.1.5 Completion Design

Figure 7 is a design of a typical CO_2 injection well, Christmas tree/wellhead combination, supplied by a major Permian Basin CO_2 EOR operator (Contek/API, 2008). Basic functional elements include:

1) *A lubricator valve at the top to access the injection tubing string for running wireline tools, such as a tracer / gamma ray combination used for injection profile management,*

2) *A CO_2/water supply valve,*

3) *Master valves to permit isolation of the injection tubing string from the CO_2/ water supply sources,*

4) *Casing head valves to permit monitoring of the pressure in the annulus between the production casing and the injection tubing string to assure the mechanical integrity of the well, and,*

5) *A Bradenhead valve to permit monitoring of the pressure between the production casing and the surface casing strings.*

The tubing and casing hangars are integral to the wellhead design.

Below the wellhead, within the production casing (Figure 8) lies:

1) *The tubing string,*

2) *At the end of which is an ON/OFF tool used to withdraw the tubing sting from the formation while leaving the packer in place,*

3) A profile nipple used for seating a plug to isolate the wellbore from the formation which allows the tubing string to be withdrawn without having to kill the well,

4) A mechanical packer, also at the end, which creates a seal between the injection tubing and the production casing, as illustrated in Figure 8.

Figure 7 - Typical CO_2 Injection Wellhead (Contek/API, 2008)

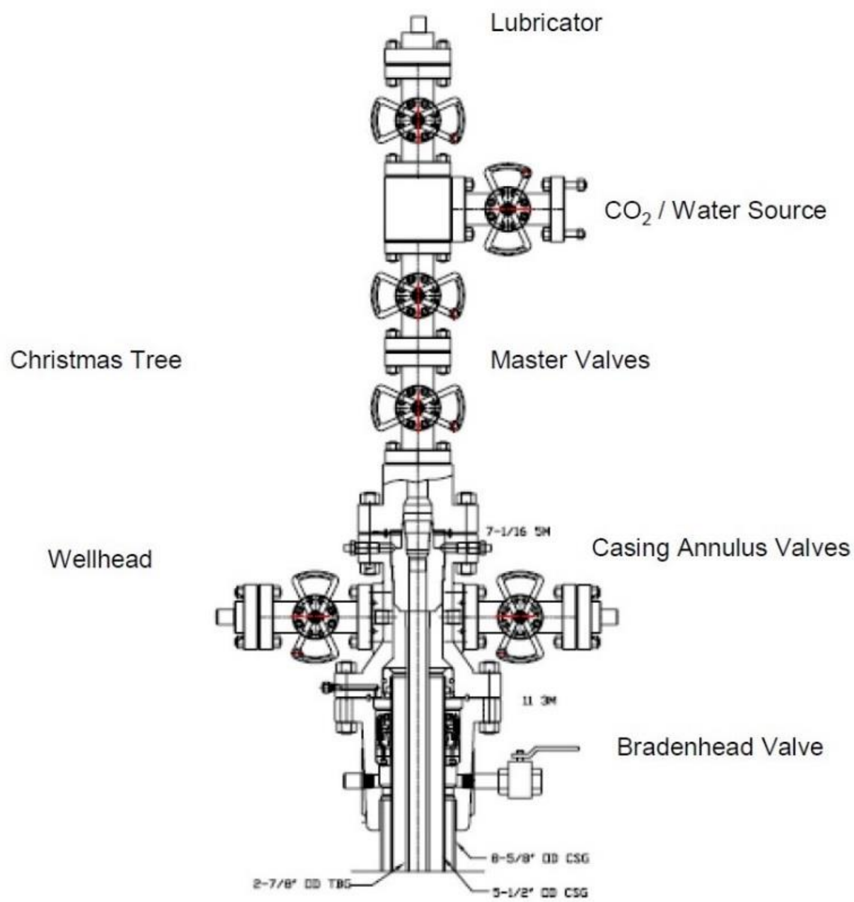
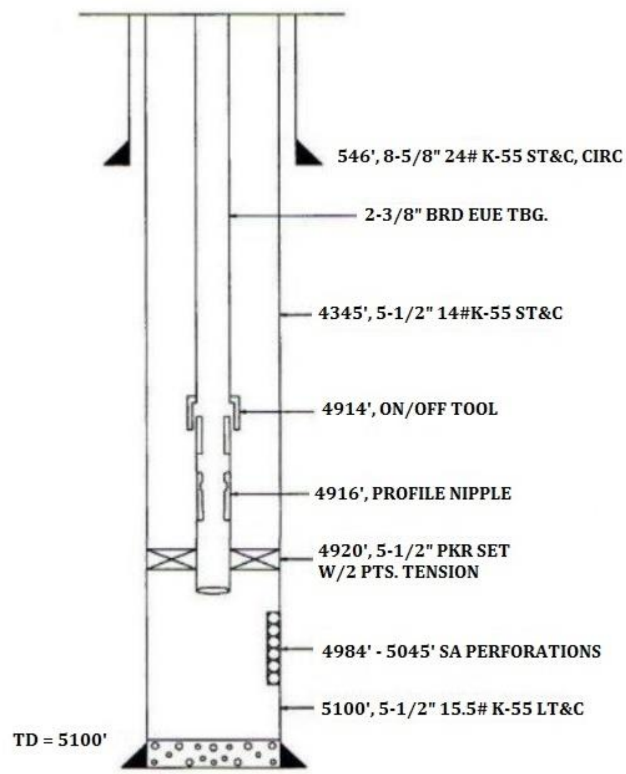


Figure 8 - Typical CO_2 Injection Well Tubing String (Contek/API, 2008)



Cased-Hole and Open-Hole Completions- For new construction, almost all wells are cased-hole completions. In isolated cases, depending on reservoir conditions, open-hole completions are still used, but are rare. Since cased-hole completions are amenable to a larger variety of profile management techniques (mechanical isolation, chemicals, squeeze cementing, etc.) than open-hole completions, they are the more common completion strategy.

2.1.6 Re-Completions of Existing Wellbores (Contek/API, 2008)

Since the inception of CO_2 EOR operations, a number of existing oil producing and water injection wells have been re-completed, that is converted, to CO_2 injection wells. Excellent reviews of major field redevelopment efforts have been presented by Folger and Guillot (1996), Power et al (1990), and Bowser et al (1989).

More recently (mid to late 2000s), the 100 year old Salt Creek Field in Wyoming has been converted to a CO_2 EOR development in which over 4,500 wells were re- completed. All the wells (with 70% drilled pre-1970s) were individually evaluated (including a number of wells that were plugged and abandoned) for adequacy of well integrity for CO_2 injection purposes and the lessons learned from this successful CO_2 EOR project have significant implications for CO_2 injection in legacy fields with a large number of legacy wells (Hendricks, 2009).

To do so, a rigorous re-completion process was developed (Contek/API 2008):

- *Where they existed, cement bond logs were examined to ascertain the condition of individual wellbores with regard to bonding between the casing and the adjoining formation. If insufficient or inadequate isolation was detected, a squeeze cement procedure was used to place cement behind the casing and a cement bond log rerun to validate successful wellbore remediation.*

- *For wells that were plugged and abandoned, a pulling unit was set up and the wellbore drilled, from the top of the surface conductor to the bottom of the target formation to remove any accumulated debris (cement, bridge plugs, tree stumps, etc.).*

- *For those wells with cement bond logs, if insufficient or inadequate bonding was detected, a squeeze cement procedure was used to place cement behind the casing and the cement bond log rerun to validate successful wellbore remediation.*

- *A casing mechanical integrity test (MIT) was performed on each well. This required pressurizing the wellbore and monitoring it, to determine if any pressure falloff occurred. If no pressure reduction was seen, the wellbore was deemed competent.*

- *If a pressure reduction was observed, it was indicative of casing leaks. The leaking section of casing was first identified and then re-sealed by squeeze cementing. In some cases, liners were run to cover the leaking section.*

Use of squeeze cement techniques and installation of liners is common oil field practice. A detailed description of both squeeze cementing and liner installation procedures for re-completed CO_2 injection wells in the Maljamar Unit has been presented by Bowser et al (1989). An excellent review of the complete procedures with specifics for converting mature wells to CO_2 injectors can be found in the work of Power et al (1990) for the North Ward Estes Field.

In the Sundown Slaughter Unit in West Texas, water injection wells, in service since the 1930's, needed significant upgrading for CO_2 injection beyond that described above. This included replacement of 10-25 feet (3.05 – 7.62 m) of surface casing onto which a new wellhead was welded and new Christmas tree attached. In general, this procedure does not appear to be routine practice for most CO_2 injection well re-completions.

All injection wells must pass current mechanical integrity tests (MIT) as dictated by appropriate regulatory bodies, state or federal. Results from the Salt Creek Field, as well as many others, validate the robustness of current re- completion and MIT practices. For wells completed with modern completion techniques, casing failures have been observed to be rare (See Table 1 and Sections 2.1.7, 2.1.8, 3.1.2, 4.3 5.1 and 6.3 – Blowouts – Case Studies).

Typical problems encountered in CO_2 Operations

The water alternating gas (WAG) and the combined water/gas injection (CGW) processes are widely used in CO_2 EOR operations (see Appendix 2). The experience from WAG field cases has been reviewed in detail by Christensen at al. (2001) and Awan et al. (2008). Of the 64 reviewed CGW operations by these authors, 37 operations use non-CO_2 gases as the injection fluid while all offshore projects use hydrocarbon gases as the injection fluid.

Typical problems encountered with CO_2 EOR operations that could occur similarly in CO_2 geological storage are shown in Table 1 and include: a) corrosion, b) channeling and early breakthrough, c) hydrate formation, d) scaling, e) asphaltene deposition, and f) pressure fluctuations due to CO_2 phase changes along the well tubing (IEAGHG, 2010).

Table 1*: Reported operation problems from WAG injection (Christensen at al., 2001/IEAGHG, 2010)*

Operation	Problems/limitations reported
Juravlevsko-Stepanovskoye	Pressure closedown due to channelling
Hassi-Messaoud	Interval of few days between injection of gas and water for pressure reduction at wellhead
Kelly Snyder	CO_2 delivery problems, compression
Rock Creek	Shortage of CO_2,, labor problems
Lick Creek	Channelling, valve problems on compressor, foaming problems in oil, severe corrosion in
Granny's Creek	Casing leak, wellhead repair, CO_2 delivery problems, channelling
Slaughter Estate	CO_2 delivery problems
Purdy Springer	Corrosion of submersible pumps
Jay Little Escambia	Injectivity reduction
Quarantine Bay	Downhole corrosion

Operation	Problems/limitations reported
Wasson Denver	Hydrate formation, froze wellhead
Fenn Big Valley	Problems with downhole pumps at high GORs
Caroline	Early breakthrough
Mitsue	Asphaltene deposition; relieved by xylene/toluene washes
East Vacuum	Asphaltene deposition after CO_2 breakthrough, corrosion, $CaSO_4$ scaling
Dollarhide	Scaling, asphaltenes
Rangely Weber	Corrosion, asphaltenes, injection problems due to temperature changes at different gas recompression limits
South Wasson	High wellhead pressures with tubing full of CO_2
Tensleep	Minor corrosion, asphaltenes
Lost Soldier	Mechanical problems with pumps due to sour gas injection
Gulfaks	Compressor specs not suitable for enriched gas injection
Brage	Tubing malfunction due to heating and expansion from injected gas
Ekofisk	Injectivity problems due to hydrate formation

Workovers

There are several major differences in wellbore remedial work between a water flood and a CO_2 flood:

- *Selection of workovers for producing wells in a CO_2 flood is not as straightforward as in a mature water flood*

- *Chemical treatment can be required to solve problems of scale, paraffin, and asphaltene deposition caused by injection of CO_2 into a reservoir*

- *CO_2 breakthrough is more costly than water breakthrough*

- *Safety considerations are more important because CO_2 increases surface tubing and casing pressures and makes well control even more important during a workover*

- *If well-kill operations are required clear brines rather than solids laden fluids (like drilling muds) are used to limit formation damage. The most common brine used is sodium chloride brine weighing 10 pounds/gal (1.2 SG) though higher pressure wells may require the use of heavier-weight brines containing salts like calcium chloride. In addition, laboratory tests with weighted bentonite muds indicate potential reductions in viscosity and density on contact with CO_2 that may result in potential well control issues (Eferemo, 2013). The use of heavier-weight brines may be reduced by shutting in the well to let it stabilize, or by switching to water injection before the workover. If possible workovers should be done through tubing to avoid pulling equipment out of the well (Jarrell et al, 2002)*

These problems are surmountable, and production problems have not been a major factor in CO_2 flooding (Hadlow, 1992). Nevertheless, injection well workovers in a CO_2 flood should be approached with caution because a decrease in injection rate may be caused by mobilization of the oil bank or by relative permeability effects, rather than by a problem that can be remediated by a workover.

Once a CO_2 injection well is put in service, profile management is the most common workover activity, with the following options:

1. *Change WAG flow rates and cycle times,*
2. *Use mechanical isolation by setting packers, casing patches, etc.*
3. *Isolate zones by squeeze cementing and/or in combination with polymer gels or chemical squeezes alone,*
4. *Set liners, and*
5. *Sidetrack the well.*

Steps 2 through 5 require wellbore intervention, and all listed activities are routine oilfield activities, and have been so for decades.

Most operators with large CO_2 EOR operations (see Section 8.4 – Oxy Denver Unit, Wasson Field, TX Case Study # 4), maintain a workover rig on location, so that they can be routinely deployed for routine workover and well maintenance activities. This ability to deploy rigs at short notice is also valuable, in the event a well control incident were to occur, so that kill operations and well control can quickly be restored. For CO_2 storage operations, particularly offshore where only a few injection wells will be drilled and active, the ability to deploy a rig to either bring an active well under control, or to drill a relief well for blowout control purposes should be an important consideration in project planning purposes.

Drilling fluid impacts from CO_2: Contamination of the drilling mud by Ca^{2+}, Mg^{2+}, carbon dioxide, hydrogen sulfide and oxygen to the drilling fluid, either at the surface or through the wellbore, produces an imbalance in the chemical equilibrium of the fluid, which can cause serious rheological or drilling problems to develop. Ca^{2+} and Mg^{2+} ions are typically present from contaminants like $CaSO_4$, $CaSO_4 2H_2O$, $MgSO_4$ or $Mg(OH)_2$.

Many formations drilled contain carbon dioxide, which when mixed with the mud can produce carbonate ions and bicarbonate ions. The presence of such ions produces a drilling fluid that has unacceptable filtration and gelation characteristics that cannot be removed by normal chemical additive methods until the carbonate and bicarbonate ions are removed from the mud. The carbonate and bicarbonate ions are removed from the mud by the addition of calcium hydroxide (Bourgoyne et al, 1991).

2.1.7 CO_2 Injection Wells versus Conventional Oil and Gas Wells

In a CO_2 injection well, the principal well design considerations include pressure, corrosion-resistant materials (tubulars and cements) and production and injection rates. The design of a CO_2 injection well is very similar to a gas injection well in an oilfield or gas storage project, with the exception that much of the downhole equipment must be upgraded for high pressure and corrosion resistance (IPCC, 2005). Upgrades may include special casing and tubing, safety valves, cements, and blowout preventers. The technology for handling CO_2 has already been developed for EOR operations and for the disposal of acid gas. Horizontal and extended reach wells can be good options for improving the rate of CO_2 injection from individual wells. The Weyburn field in Canada is a good example in which the use of horizontal injection wells is improving oil recovery and increasing CO_2 storage. The horizontal injectors reduce the number of injection wells required for field development with the added advantage of creating injection profiles that reduce the adverse effects of preferential flow of injected CO_2 gas through high-permeability layers.

Proper maintenance of CO_2 injection wells is necessary to avoid loss of well integrity. Several practical procedures can be used to reduce loss of well control (LWC) incidents including blowouts and to mitigate the adverse effects if one should occur. These include periodic well integrity surveys, improved BOP equipment maintenance, improved crew awareness, contingency planning and emergency response training.

The biggest difference between a typical gas injection well and a CO_2 injection well is cement and casing to protect from CO_2 corrosion. For CO_2 storage wells, special CO_2 – resistant cements should be used and corrosion resistant alloy (CRA) steels/chrome steel etc. should be used for tubulars and equipment that comes into contact with CO_2. In the case of wet gas, use of CRA material is essential.

For CO_2 injection through existing and converted wells, key factors include the mechanical condition of the well and quality of the cement and well maintenance. A leaking wellbore annulus can be a pathway for CO_2 migration. Detailed logging and surveillance programs can be conducted on a regular frequency to verify and confirm well integrity and to protect ground water resources and other hydrocarbon/permeable zones and prevent reservoir cross-flow. All injection wells must be equipped with a packer to isolate pressure and fluids to the injection zone and all materials used should be designed to anticipate peak volume, pressure and temperature (See Sections 2.1.2, 4.3, 4.4 and Section 6.3 – Blowouts, Case Studies).

2.1.8 Well Construction Considerations for CO_2 Storage Wells (Smith et al, 2011 and Cailly et al, 2005)

For long-term storage, CO_2 injection may be into either a depleted oil/gas reservoir or saline aquifer. If CO_2 is injected in a dry supercritical state with the risk of corrosion being low, the use of standard low alloy carbon steel tubulars, sometimes with the use of inhibitors, will be adequate during the injection phase (Cailly et al, 2005)

However, during periods of well shut-in or long term suspension the corrosive water contact with the tubing opposite the injection interval has to be considered and the corrosion rate would be sustained during periods of inactivity. If the tubing is removed and the well permanently abandoned, then the impact of corrosion will not be a factor. If the tubing is kept in place during the abandonment phase, then it may be necessary to consider CRA material for the tubing string to resist the aggressive water over the long term. Also the need for annulus monitoring for abandoned wells may have to be considered.

During the long-term storage phase, the supercritical CO_2 can be hydrated with water contained in the reservoir and wet CO_2 or acid brine can reach the well. Then the acidic water phase can degrade the cement protecting the steel casing and the effects of the degradation products from cement on steel can be severe. The problem is that the exact state of the CO_2 rich phase is not precisely known, and that the corrosion process of aqueous supercritical CO_2 is not yet fully characterized. The properties of CO_2 over a representative range of pressures and temperatures and corrosion rates for aqueous CO_2 should be defined by laboratory testing. Modeling thermodynamic studies will need to be conducted to define long term equilibrium conditions, in order to avoid failures after injection. The presence of corrosive fluids initially present in the reservoir must also be taken into consideration. Work done by Seiersten (2001) showed that wet CO_2 corrosion rates on carbon steel at high pressures are smaller than expected from models developed at low pressures. Further research is needed to understand this phenomenon, which could be partially explained by the formation of a protective carbonate film on the surface of the steel (Cailly et al, 2005).

Other factors to consider include:

On-off injection: Intermittent supply of CO_2 typically caused by disrupted supply during unloading from a ship, or well intervention for repairs, has implications for well integrity. On-off injection leads to cyclical heating and cooling causing the casing to expand more than the surrounding materials. This condition causes radial and hoop stresses in cement and can cause both debonding (between the cement and the casing and/or rock) or disc and regular fractures. Both of these effects can result from thermal changes. This can also have an impact on nucleation conditions (e.g. salt) and borehole deformation. Intermittent injection will affect both well integrity and injectivity. The research-based advice is to avoid extensive pressure testing of annular barriers, ensure robust well construction, and minimize thermal cycling (through choice of injection parameters and well materials/fluids). Also, salt precipitation and borehole deformation are likely to occur in injection wells. The average time for problems to occur is approximately two years if wells are operated outside their initial design envelope and there is a strong dependence on quality of cementation (Torsaeter, M., "IEAGHG Modelling and Risk Management Combined Network Meeting", 2018).

Brine composition: Injection may be into either a depleted oil or gas reservoir or saline aquifer. The depleted reservoir will be filled with formation water, with typical chloride ion content between 20,000 - 120,000 ppm. Formation waters in carbonate rocks are typically in the 1500 – 2500 ppm range (saturated), although some waters (from sandstones) may be very low in bicarbonates. A saline aquifer may be more concentrated with chloride ions between 150,000 - 200,000 ppm and bicarbonate content varying between 0 – 2500 ppm depending upon the rock type (Smith et al, 2011).

Injection fluid composition: While the composition of CO_2 EOR oilfield fluids is fairly consistent from a reducing perspective, CO_2 produced from coal-fired power plants may contain a variety of oxidants including oxygen, traces of SO_2 and NO_2. The aggressive chemical components in the injected gas are:

- *CO_2 – controls the basic material selection*

- *H_2S – shifts the choice of materials significantly because of the risk of pitting and/or hydrogen loading*

- *O_2 – introduces pitting risk*

- *SO_2 and NO_2 – make the environment more acidic*

Wellhead and Xmas Tree: With the injection fluid being dry at wellhead conditions, standard low alloy carbon steel should be adequate for Xmas tree and wellhead components. SS 316 trim is recommended to provide long term sealing capability.

Injection Completion String Recommendations can be summarized as follows:

- *No corrosion risk in upper section of tubing. Possible risk of attack on tailpipe and casing below packer due to contact/wetting during well shut-in – CRA material depending upon environment*

- *Upper section of tubing above packer, L80 carbon steel, completion components 13Cr stainless steel*

- *High performance tubing connections to minimize CO_2 leakage to annulus*

- *Annulus fluid treated with oxygen scavenger and corrosion inhibitor to prevent galvanic corrosion, and with biocide to mitigate against microbial influenced corrosion (MIC)*

- *Corrosion logging of tubing every 4 to 5 years (or at a higher frequency) as directed by regulatory agency (Texas Railroad Commission or other State Oil and Gas Regulatory Agencies in the U.S. for CO_2 EOR wells and US EPA for CO_2 storage injection wells) and during every workover.*

Cements: Acid and CO_2 resistant cements to be used opposite the injection interval. Cement integrity to be confirmed opposite casing shoe with pressure test and with cement bond logging. The quality of cementation is crucial to assure life-cycle well integrity.

Well Operations: To assure and maintain well integrity, key parameters to be monitored daily or continuous include:

- *Surface tubing pressure and temperature*

- *Bottom hole pressure and temperature*

- *Annuli pressures*

- *Hours of injection per day (since shut-in periods represent higher risk of water diffusing back into the wellbore)*

- *Results of well integrity/pressure tests at regular frequencies and chemical analyses of well fluids sampled from the well annuli also need to be checked and monitored. Any annulus pressure buildup* *should be monitored and if SCP is indicated, diagnostics should be performed and appropriate remedial steps taken to restore well integrity or the well shut-in, pending repair.*

- *There is mixed performance of various polymeric linings at high pressure conditions. For deeper wells with > 350 bar (5,076 psi) at bottom hole conditions, linings would not be recommended due to blistering concerns (Smith et al, 2011)*

- *Whilst the WAG service typical of many USA wells results in particularly aggressive intermittent wet and dry service at the bottom of the well, the experience in several cases of corroded liners and casings is an indication that the conditions would be aggressive in CCS service if the aquifer flowed back to the wellbore over time (e.g. during prolonged shut-in, or at abandonment). Thus, selection of Corrosion Resistant Alloys (CRA) for the bottom of the well would be advised, following the approach taken by Statoil (now Equinor)*

- *High performance tubing connections are necessary to minimize the risk of the CO_2 leaks to the annulus*

- *Materials selection used in existing CO_2 projects has often been 25Cr duplex stainless steel, but that may not be applicable where the components in the injected fluid stream are more acidic or oxidizing. 25Cr stainless steel will de-passivate at around a pH value of 2.0*

2.1.9 Other Analogs to CO_2 Injection

Acid Gas Injection (IEAGHG, 2010)

In order to reduce atmospheric emissions of hydrogen sulfide (H_2S) produced from “sour” hydrocarbon pools, oil and gas producers in western Canada (Alberta and British Columbia) have been injecting acid gas (H_2S and CO_2 with minor traces of hydrocarbons) into deep geological formations. The first acid gas injection in Alberta into a depleted gas reservoir started in 1990 and into a saline aquifer in 1994. By 2007, 48 permits for acid gas injection were approved in western Canada (41 in Alberta and 7 in British Columbia) of which 27 operations inject into saline aquifers. General and some site specific information on acid gas injection in western Canada can be found in several publications. Additional sour gas injection projects globally include the Harweel Cluster, South Oman project (O’Dell et al, 2006), LaBarge in Wyoming (Benge and Dow, 2006) and the Supergiant Kashagan Field (Malik et al, 2005).

The technology and experience developed in acid gas injection operations (i.e., well design, materials, leakage prevention and safety) can be adopted for large-scale operations for CO_2 geological storage, since a CO_2 stream with no H_2S is less corrosive and less hazardous. A major concern with the injection process is the potential for formation damage and reduced injectivity in the vicinity of the injection well, which could possibly be a result of fines migration, precipitation and scale potential, oil or condensate banking and plugging, asphaltene and elemental sulfur deposition, or hydrate plugging (Bennion et al, 1996). Injection rates for most acid gas injection projects are generally low (<100Kt/year). However, a few operations inject at rates close to anticipated for future CO_2 geological storage. Acid gas injection rates of ~ 1 Mt/year at LaBarge are comparable to Sleipner injection rates. Other smaller acid gas injection operations include Talisman's Sukunku operation in British Columbia (up to 300 Kt/year) and the Zama (Apache Canada Ltd.) and Brazeau River (Keyspan Energy Canada) operations in Alberta injecting up to 120 Kt/year. Independent of the injection rate, problems related to loss of injectivity due to geochemical reactions of the injected gas with the reservoir rock may be applicable to larger-scale injection of CO_2.

The main remediation options applied in acid gas injection are acid stimulation and completion of additional reservoir intervals. At five injection sites, acid gas showed up in nearby production wells. In some cases, the breakthrough of CO_2 and H_2S occurred at later times than predicted by reservoir modelling, mainly due to the accuracy of the geological model and uncertainty of reservoir heterogeneity (Bachu et al., 2007b; Dashtgard et al., 2008; Pooladi-Darvish et al., 2008). In the case of the Atcheson site, breakthrough of CO_2 occurred after 13 years of injection at a distance of 3.6 km in a producer that was initially thought to be in a separate oil pool (Bachu et al, 2008). An updated geological interpretation resulted in new pool delineations. This example shows that even at low injection rates (~ 5 Kt/year), the hydrodynamic drive imposed by producing wells can have a significant impact on the migration distances and directions of injected CO_2 (IEAGHG, 2010).

Natural gas storage

The primary purpose of UGS is to provide a buffer between a relatively constant supply and a variable demand for gas, allowing large supplies of natural gas to be stored during times of low demand and withdrawn from storage when demand is high. The first underground gas storage (UGS) (* Includes underground storage of natural gas and natural gas liquids) operation in the U.S. began in 1916 near Buffalo, New York. As of December 2015, according to the U.S. Energy Information Administration (U.S. EIA), the U.S. has 415 active UGS projects with approximately 17,500 storage wells operated by about 120 companies, more than any other country in the world (UGS Regulatory Considerations). Over 80% of the storage wells were completed in 1980s or earlier.

There are three main types of gas storage formations:

- *Depleted oil and gas reservoirs are the most common type (~ 80%). They are well characterized and typically contain some "cushion gas" from the production phase,*
- *Aquifers account for ~ 10% and although more expensive than depleted oil and gas fields are widely distributed and located near population centers,*

- *Salt caverns account for ~ 10% and are formed in salt domes or salt beds (mostly located in the Gulf Coast). The operator has the ability with salt cavern storage to perform several withdrawal and injection cycles/year.*

2.1.10 CO_2 EOR and CO_2 Storage Well Costs

The geological properties of the receiving formation determine how easily CO_2 can be injected. This in turn determines the number of wells required for injection or the total annual amount of CO_2 that can be injected both in absolute ($) terms and unit ($/ton) terms. The geologic properties that influence injectivity include: permeability, fracture gradient, formation thickness, formation depth, well type, and hydraulic fracturing (IEAGHG, 2010). The costs associated with a CO_2 EOR and CO_2 storage project are site and situation-specific. In general, oil prices have by far the larger impact on the economic viability of a CO_2 EOR project, with the second largest impact being the cost of CO_2. Total CO_2 costs (both purchase and recycle costs) can amount to 25% to 50% of the cost per barrel of oil produced (Advanced Resources International, ARI 2011), and operators have historically strived to optimize and reduce the cost of its purchase and injection wherever possible.

Offshore versus Onshore CO_2 Injection Costs

There are significant differences between the costs and logistics of onshore and offshore CO_2 injection and can affect the viability of CO_2 injection markedly, and these differences apply worldwide. Therefore, everything else being the same, the economic viability of injecting a given rate of CO_2 is significantly greater for onshore locations than offshore locations. For a given carbon price, offshore locations might be limited to fewer injection wells and lower CO_2 injection rates than would be possible for onshore locations (IEAGHG, 2010). Offshore wells drilled in shallow shelf waters [(less than 100 meters (328.1 feet)] may cost 10 times more than a conventional onshore well, while a deep water injection well may be even more costly (due to mobilization/demobilization charges and other constraints with platforms/infrastructure, distribution, compression, legal, geographical and distances etc. – See Appendix A2.6.1 – Offshore CO_2 EOR Challenges).

For offshore locations, the constraints on designing the injection systems and locating the wells relate to the water depth, the seabed conditions, the number of platforms and the type of injection wells. Deep water injection sites will limit the number and type of platforms that can be used and therefore the number of wells. For instance, floating or tension-leg platforms might be more appropriate for deep water locations and these will constrain the number of injection wells that can be accommodated. In contrast, fixed platforms can be installed in shallow waters [(less than 200 meters (656 feet)] that can accommodate many wells. The condition and topography of the seabed will also affect the location of the platforms and the wells (IEAGHG, 2010).

For deep water CO_2 injection projects (with few injection wells), sub-sea wells with tie-back flowlines to the host platform might be the most appropriate design for the injection system, and this is well established technology (IEAGHG, 2010).

Summary of CO_2 EOR Injection Project Costs – US Onshore (ARI, 2011)

1. *Well Drilling and Completion. New wells may need to be drilled to configure a CO_2 EOR project into an injection/production pattern amenable for CO_2 EOR production. Well drilling and completion costs are generally a function of location and the depth of the producing formations*
2. *Lease Equipment for New Producing Wells. The costs for equipping new production wells consists of fixed costs for common items such as free water knock-out, water disposal and electrification and depth-related costs for pumping equipment*
3. *Lease Equipment for New Injection Wells. Costs include gathering lines, a header, electrical service, a water pumping system, and a depth-related component dependent on surface pressure requirements*
4. *Converting Existing Production Wells to Injection Wells. To implement a CO_2 EOR project, it may be necessary to convert some existing oil production wells to CO_2 EOR production and injection wells, which requires replacing the tubing string and other mechanical integrity upgrades and adding distribution lines and headers. For existing fields, surface equipment for water injection may already be in place. Again, well conversion costs will include a fixed cost and a depth-related component.*
5. *Rework an Existing Water flood Production or Injection Well for CO_2 EOR. These costs will be depth-dependent.*
6. *Annual O&M, Including Periodic Well Workovers. First workover costs are, on average, about double for CO_2 EOR wells compared to conventional oil and gas wells because of the need for more frequent remedial well work, and second traditional lifting costs should be subtracted from annual water flood O&M costs to allow for the more rigorous accounting of liquid lifting volumes and costs for CO_2 EOR.*
7. *CO_2 Recycle Plant Investment. Operation of a CO_2 EOR project requires a recycling plant to capture, separate and re-inject the produced CO_2. The size of the recycle plant will depend on peak CO_2 production and recycling requirements, with the O&M costs of CO_2 recycling being a function of energy costs.*
8. *Fluid Lifting for CO_2 EOR. Liquid (oil and water) lifting costs are based on total liquids production and include liquid lifting, transportation, and re-injection.*
9. *CO_2 Distribution. The CO_2 distribution system is similar to the gathering systems used for natural gas. A distribution "hub" is constructed with smaller pipelines delivering purchased CO_2 to the project site. The distribution pipeline cost is dependent on the injection requirements for the project, and the distance of the CO_2 EOR project from the CO_2 source.*

CO_2 Storage Well Construction Costs (US Onshore)

Table 2 - ***Estimated 2008 costs for construction of a CO_2 geologic storage injection well in the U.S. (USEPA, 2008)***

Note: *Inflation indices for upstream oil and gas facilities are closely related to the price of crude oil and natural gas, which has particularly in the case of crude oil seen drastic fluctuations between 2008 and 2018. The inflation indices have varied between < 1 to above 2.2 during this period and are expected to be in the range of 1.1 to 1.2 for 2017/2018.*

Cost Reporting Heading	Unit Cost Heading	Cost Item	Cost Algorithm	Data Sources
Injection Well Construction	Site Selection and Evaluation	Conduct front-end engineering and design (FEED)	$200,000/site + $40,000/injection well	ICF estimate
Injection Well Construction	Land and Land Use Rights	Obtain rights-of-way of surface uses (equipment, injection wells)	$20,000/annum	ICF estimate. Cost of land rights are highly variable
Injection Well Construction	Land and Land Use Rights	Lease rights for subsurface (pore space) use	Upfront payment of $50/acre (additional injection fees under O&M costs)	ICF estimate. Cost of land rights are highly variable
Injection Well Construction	Permitting Costs	Land use, air emissions, water permits	$100,000/site+$20,000/ square mile	ICF estimate
Injection Well Construction	Permitting Costs	UIC permit filing	$10,000/site+$5,000/inj ection well	ICF estimate
Injection Well Construction	Drilling & Equipping Injection Wells	Standard injection well cost	Use look-up table. $/foot = $ 210 to $ 280/foot typically down to 9,000 feet	Drilling cost estimated from 2008 data
Injection Well Construction	Drilling & Equipping Injection Wells	Corrosion resistant tubing	Additional $ 1.10/foot for GRE lining	Estimated from SPE article on GRE
Injection Well Construction	Drilling & Equipping Injection Wells	Corrosion resistant casing	Additional $ 1.75/foot for CRA casing	PSAC and Preston Pipe Report
Injection Well Construction	Drilling & Equipping Injection Wells	Cement entire length of casing	$ 1.15/foot of length	Based on 2008 PSAC Well Cost Study
Injection Well Construction	Drilling & Equipping Injection Wells	Use CO_2-resistant cement	Add 25% to total cementing costs	Initial estimate
Injection Well Construction	Drilling & Equipping	Set packer no more than 100 feet above highest perforation	Affects tubing length	Assumed to be standard cost

Cost Reporting Heading	Unit Cost Heading	Cost Item	Cost Algorithm	Data Sources
	Injection Wells	(or as required by regulator)		
Injection Well Construction	Drilling & Equipping Injection Wells	Injection pressure limited to 90% of fracture pressure of injection formation	Affects maximum injection flow rate, number of wells needed	
Injection Well Construction	Injection Equipment (pumps, valves, measurement devices)	Pumps	$ 1500/HP, installation of electrical service adds $ 20,000/well site	Estimated from EIA Oil and Gas Lease Equipment and pipeline prime mover/compressor cost from FERC
Injection Well Construction	Injection Equipment (pumps, valves, measurement)	Wellhead and Control Equipment	Cost/well will vary depending on CO_2 injected/day – estimated $ 500/day	Based on 2008 PSAC study
Injection Well Construction	CO_2 pipeline (within facility)	All elements of pipeline costs	$ 60,000/inch-mile	Estimate from FERC pipeline data.

3.0 WELL INTEGRITY

3.1 WHAT IS WELL INTEGRITY? CONCEPTS AND TERMINOLOGY

Oil field development can be divided into exploration, development, production and abandonment phases. For offshore field developments, different types of drilling rigs can be used. Examples are bottom-supported platforms like Jack-up rig, steel jacket-based platform, concrete-based platform and Mobile Offshore Drilling Unit (MODU) like semi-submersible drilling rig and drill ship.

There are basically two types of wells:

Exploration well: The primary purpose of an exploration well is to find potential reservoirs for development and production. These wells are normally plugged after logging/testing.

Production/injection wells: After drilling, these wells are completed for production and/or injection. Water or gas is normally injected into the reservoir to maintain pressure. After the production phase has ended and the economic limit has been reached, the well is plugged and abandoned.

Well Integrity is defined in NORSOK D-010 as: "Application of technical, operational, and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the lifecycle of a well". Another accepted definition is given by ISO TS 16530-2 "Containment and the prevention of the escape of fluids (i.e. liquids or gases) to subterranean formations or surface".

NORSOK D-010 is a functional standard and sets the minimum requirements for the equipment/solutions to be used in a well, leaving it to the operating companies to choose the solutions that meet the requirements. The operating companies then have the full responsibility for being compliant with the standard.

Well Integrity in its simplest definition can be defined as a condition of a well in operation that has full functionality and two qualified well barrier envelopes. Any deviation from this state is a minor or major well integrity issue. Common integrity issues are often related to leaks in tubular or valves, but can also be related to reservoir issues as loss of zonal control. Any factor that leads to a functional failure is a loss of well integrity. The challenge is to define all possible scenarios.

With the significant technological evolution in the drilling industry during the past 30 years (such as subsea installations and extended reach drilling), more complex systems are now in place. The increased complexity is readily managed by close attention to evaluation of each system and how they impact the total well integrity.

Organizational solutions are also required to ensure the required well integrity is maintained. This will include: (1) the operating company ensures that people with the right competence are working with well operations and they are up to date with well operations and latest well status, (2) good communication between the parties involved so that the correct information is shared and passed during shift handovers and during well status changes etc. Many problems and accidents have occurred due to poor handover documentation or communication.

Norway's Petroleum Safety Authority (PSA) have published the regulatory requirements regarding well integrity aspects like organizational solutions, management system, competence and training, work processes, operational organization, emergency preparedness etc.

Loss of well integrity is either caused by mechanical, hydraulic or electric failure as related to well components, or by wrongful application of a device, such as a BOP (blow out preventer). This shows that we must go beyond the technical aspects and also consider well management aspects. In hindsight many well incidents have become worse because of wrong decisions. Education and training therefore form an important basis for improved well integrity.

Consequences of loss of well integrity - Blowouts or leaks can cause material damage, loss of life/personnel injuries, loss of production/revenue, and environmental damages resulting in costly and risky repairs. This shows that well integrity depends not only on equipment robustness, but on the total process, the competence and resources of the organization and the competence of the individual.

3.1.1 Mechanical Integrity

Testing

State regulatory agencies such as the Texas Railroad Commission and U.S. Environmental Protection Agency specify the technical requirements of the mechanical integrity test (MIT) for CO_2 EOR and CO_2 GS (geologic storage) and the required frequency of testing. For Texas, MITs are required:

1.0 Prior to putting a new well into service,

2.0 After any workover (squeeze cementing, placement of liners, fracturing, etc.), and, *3.0 Wells completed with surface casing set and cemented through the entire zone of usable quality groundwater are required to be tested every five years. Wells without full surface casing protection for usable quality groundwater are required to be tested more frequently.*

Similar requirements exist for other states and regulatory bodies.

Regulatory MIT's can be done several ways however they typically involve pressurizing the tubing-casing annulus and monitoring the annulus and tubing pressures for a set period of time and observing whether or not it changes. If so, the cause of the change must be identified and remedied.

Component Integrity

As industry experience has matured, the integrity of CO_2 injection well components has improved correspondingly (Contek/API, 2008). For new wells that use completion techniques and mechanical components with appropriately chosen materials of construction, current experience suggests that integrity lives on the order of 20 to 30 years for tubulars and well beyond for wellbores can be expected.

Leak Detection and Well Repair Methods

If a CO_2 injection well has failed a mechanical integrity test, the operator must take it out of service, identify and remedy the problem and then re-test the well before putting it back in service.

Tubing Leaks

During the mechanical integrity test procedure, tubing leaks are typically indicated by increases in casing head pressure. The following is an example of how an operator might repair a tubing leak.

1. *Initially, the operator sets a blanking plug in the profile nipple at the bottom of the tubing string to establish a seal between the wellbore and the producing formation.*

2. *Then the tubing is pressurized. If the pressure holds, the tubing is competent and the problem lies with the casing. Nonetheless, the tubing string must be removed from the well.*

3. *If the pressure does not hold, then a leak exists in either the tubing string or in the seal of the ON/OFF tool at the bottom of it. It is necessary to kill the well and remove the tubing string from the well.*

4. *To kill the well, the operator, perforates the tubing string just above the ON/OFF tool and circulates kill fluid (weighted brine) to the surface. This displaces the chemically treated water in the casing/tubing annulus.*

5. *The Christmas tree is removed from the well, a blowout preventer (BOP) is installed and the tubing is removed.*

6. *After removal of the tubing, the ON/OFF tool manufacturer checks the integrity of its seal. As appropriate, it is either replaced or reinstalled.*

7. *Then the tubing is run in the well and hydro-tested for leaks. When a leak is found, the failed tubing joint is replaced and hydro-tested again. If no leaks are detected, this usually indicates that a failure occurred in a collar which was remedied as the tubing was rerun.*

8. *When the entire tubing string has been run into the well the,*
    a. *BOP stack is removed,*
    b. *Christmas tree replaced,*
    c. *Kill fluid displaced from the hole,*
    d. *Tubing re-engaged on the ON/OFF tool, and,*
    e. *Blanking plug removed.*

9. *Finally, a mechanical integrity test is rerun and the well returned to service.*

<u>*Casing and Packer Leaks*</u>

If the tubing has been shown to be competent, inspection and remedy of casing leaks must now be addressed. The following is an example of how to repair a casing leak:

1.0 The operator inserts a temporary test packer on tubing into the well within a short distance above the injection packer.

2.0 The system is pressurized and observed. If the pressure falls, the injection packer requires replacement.

3.0 If the pressure holds, then the leak is in the casing above the injection packer. To find the leak's location, the test packer is successively moved up the wellbore, reset, and pressure tests performed, until its location is isolated. Frequently, leaks occur at the collars between adjacent casing joints.

4.0 Once the location of the casing leak has been found, the operator can remedy it in several ways, including:
    a. *Squeeze cementing , chemical sealant squeezes, or,*
    b. *Insertion of a new liner (fiberglass or steel) over the leaking section.*

The choice of techniques is dictated by the severity of the situation, the geometry and state of the wellbore and operator experience.

Once a casing leak has been repaired, the well is mechanically reassembled, as per the steps given above, and a mechanical integrity test performed.

This procedure for detecting tubing and casing leaks is indicative of that used in CO_2 EOR operations in the Permian Basin. Leak detection methods are a constantly evolving part of oilfield technology that use sophisticated wireline tools based on the principles of radioactive, acoustical, or thermal phenomena. With regard to the latter, the work of Johns, et al, 2006 is illustrative of research and development efforts to identify cost effective methods for identifying small tubing and casing leaks typical of those commonly encountered in CO_2 injection wells.

It should be remembered that, in CO_2 injection wells, coated or lined tubing is normally used. Thus, use of wireline tools to detect a tubing leak could have the undesired effect of damaging the coating which can lead to further damage to the tubing. This consideration is a principle factor for using the test procedure described above. For CO_2 storage wells, however, where dry CO_2 would be injected and thus uncoated or unlined metal tubulars could be used, wireline methods offer a viable and cost effective means for tubing leak detection.

3.1.2 Well Integrity Assessment of CO2 EOR Wells in U.S.

Sustained CO_2 well integrity in most US States compares favorably with the sustained integrity of conventional wells even with CO_2 exposure having a greater potential for corrosive damage. Most US states' instances of significant noncompliance represented less than 1 percent of their total well inventory during 2008 through 2012. However, in some States this is not the case. For example, from 2008 through 2012, instances of significant noncompliance occurred in Texas from 2 to 11 percent of the state's total Class II well inventory. Table 3 below shows the statistics of noncompliance violations of CO_2 wells in various States, which includes not submitting data for the years 2008 through 2012.

Table 3 - Percentage of Class II CO_2 EOR Wells with Significant Noncompliance Violations Compared to Total Class II EOR Wells in Select States for Years 2008 through 2012 (GAO, 2014)

State in USA	2008	2009	2010	2011	2012
California	0%	No data	0%	2%	0%
Colorado	0	0	No data	0	0
Kentucky	2	0	0	No data	No data
North Dakota	No data	0	0	0	0
Ohio	0	No data	0	1	1
Oklahoma	0	0	0	0	0
Pennsylvania	0	0	0	No data	No data
Texas	5%	4%	2%	7%	11%

The data reported in Table 3 does not report the actual number of violations but only the percentage of significant noncompliance violations. The amount of significant noncompliance reported by states can vary in part because state and EPA regional agencies interpret the definition of significant noncompliance differently. For example, Texas considers all delinquent mechanical integrity violations as significant noncompliance, and Ohio said that all mechanical integrity failures are considered to be significant noncompliance regardless of their resolution. However, the guidance for reporting significant noncompliance requires reporting when the loss of integrity causes the movement of fluid outside the authorized zone, if such movement may have the potential for endangering underground sources of drinking water. The GAO 2014 Report also briefly summarizes whether the risk assessments that are currently being developed for CO_2 injection wells are appropriate and if improvements can be made, particularly the potential to identify and remediate wellbore integrity issues.

3.2 BARRIER PHILOSOPHY AND REQUIREMENTS

During well design and construction, the barrier requirements are driven by the design basis and the identified hazards. These hazards can change over the life of the well's life cycle or may actually be introduced during the construction of the well. From a well integrity management process, the relevancy is to understand the risk associated with exposure to certain hazards and that these are clearly defined in the well operating limits at well handover so that mitigating controls can be applied over the well's life. The well barrier design and construction process objective should address the issues such that the barriers over the well's lifecycle assure containment that can be effectively managed and verified. This can be a challenge as many wells undergo changes in their status from their original completion over their lifecycle (for example conversion of a depleted production well to an injection well) and lack of proper handover documentation after a change in well status during a well's lifecycle.

Some examples of barrier elements that may have to be managed during the design/construction stage to assure that the wells maintain integrity over their lifecycle are:

- *Internal oxygen-related corrosion*
- *CO_2 corrosion*
- *H_2S corrosion*
- *Chloride stress cracking*
- *Stress cracking caused by bromide mud and thread compound*
- *Microbial-induced corrosion (MIC)*
- *Other chemical corrosion*
- *Acid corrosion (e.g. from stimulation fluids)*
- *External corrosion from:*
    - *Aquifers*
    - *Surface waters*
    - *Swamp or sea environments*
    - *Sand/solids production*
    - *Scale deposition*
    - *Erosional velocities*
    - *Emulsion formation*
    - *Wax and hydrate deposition*
    - *Compatibility between components, electrolytic corrosion*

Load cases as a result of:

- *Thermal effects*
- *Fatigue*
- *Subsidence*
- *Stimulation*
- *Well kill*
- *Injection*
- *Production*
- *Evacuation*
- *Trapped pressures*
- *Casing wear*
- *Earth model fractures (see mechanical earth model (MEM) in Definitions/Glossary in Appendix 1)*
- *Pore pressures*
- *Permafrost movement*
- *Squeezing chalks*
- *Earthquake*
- *Subsidence*

3.3 BARRIER VERIFICATION AND DIAGNOSTICS

At various phases of a well's lifecycle, the integrity of the well barriers and/or well barrier elements should be verified. The verification may involve pressure measurement, tagging, pressure testing, leak testing, leak off testing, well logging or flow rate measurement. If anomalous behavior is observed then a diagnostic process is initiated, usually to determine the location and magnitude of the leak.

To determine whether the well barrier has an acceptable level of integrity, the barrier verification results are compared with the performance standards (or acceptance criteria) that apply to the well. Some oil and gas companies have their own in-house standards and some regulatory agencies with jurisdiction may prescribe the minimum verification requirements for certain well barrier elements.

Companies commonly adopt performance standards based on the publically available reference documents listed in Appendix 4.

Since these documents are not consistent in all aspects, it is important for a company's well engineering management system to explicitly define the well barrier elements (and/or the critical safety elements) and the performance standards that shall apply.

3.4 MANAGING ABNORMAL CASING PRESSURE AND SUSTAINED CASING PRESSURE

Wells are designed and constructed to allow for operation with some pressure on the annuli. This pressure only becomes a problem when there is an indication of a well integrity issue or if the maximum allowable wellhead operating pressure (MAWOP) has been exceeded. Therefore, monitoring of the annular pressure is very important on a continuous basis and to understand the source of the pressure.

NORSOK D-010 states that the A-Annulus pressure for all wells and B-Annulus pressure for multi-purpose and annulus gas lift wells shall be monitored through continuous recording of the annulus pressure to verify the integrity of the well barrier. (Note: A-Annulus is defined as the annulus between the production tubing and production casing, while the B-Annulus is defined as the annulus between the production casing and next outer casing – NORSOK D-010 and API RP 90). Well parameters such as temperatures and rates shall also be monitored to facilitate correct interpretation of pressure trends and identification of abnormal pressure behavior. Similar requirements are given in API RP 90 and API Standard 65-2.

3.4.1 Types of Annular Pressures

There are three main types of annular pressures encountered in wells: Thermal Pressure (TP), Applied Pressure (AP) and Sustained Casing Pressure (SCP).

Thermal Pressure (TP)

Wells with fluid filled enclosed annuli will exhibit thermal pressure changes during warm-up and cool down periods. During normal trouble-free operation the annuli pressures will show a clear and predictable dependency mainly on the well temperature, but also on pressures in adjacent annuli or tubing and the flow rate.

For example, during the start-up of a producer, as the well is warmed up, it is expected that the annulus pressure for a liquid filled annulus will increase. The opposite is expected when the well is shut-in. When the temperature and flow rate are stable the annuli pressures should also be stable. After a start-up of a well, the annulus pressures can be expected to stabilize at the same values as before the well was shut-in, if no top ups or bleed downs have been done and the stabilized temperature is the same.

The expected annulus pressure behavior for injection wells will depend on the difference in temperature between the injection fluid and the surroundings of the well. For wells where the injection fluid is much cooler than the surroundings, the annulus pressures can increase significantly when the well is shut-in and the temperature increases.

It is important to recognize the effect of changing temperatures and to monitor annulus pressures closely during the startup of new wells. Pressure should not be bled off in this instance unless the Maximum

Operating Pressure (MOP) has been breached. It is vital to monitor annulus pressures closely during initial start-up of new wells as pressure can build up rapidly and result in over-pressurized annuli.

For an enclosed system where the fluid cannot expand, the density will remain constant and the increase in temperature will result in a significantly increased pressure. If the increased pressure cannot be bled off, the trapped annulus pressure may result in burst or collapsed casing or tubing and loss of well integrity. The effect with brine filled annuli will be larger than with fresh water.

A common way to reduce temperature induced pressure is for the cement for the next casing string not to cover the previous casing shoe. The exposed open-hole section may lead to a small fluid loss resulting in a reduced annular pressure.

Applied Pressure (AP)

Pressure may be applied to an annulus for various purposes such as gas lift, cuttings re-injection (CRI), compensating for bull-heading loads, or assisting in annulus monitoring. The applied pressure may also come from pressure containment tests, from mono-ethylene-glycol (MEG)/methanol lines to top up or prevent hydrates and from hydraulic pressure leaks. Care must be taken to ensure that this pressure is bled down after testing to a suitable value to ensure that thermal pressure does not exceed the MOP.

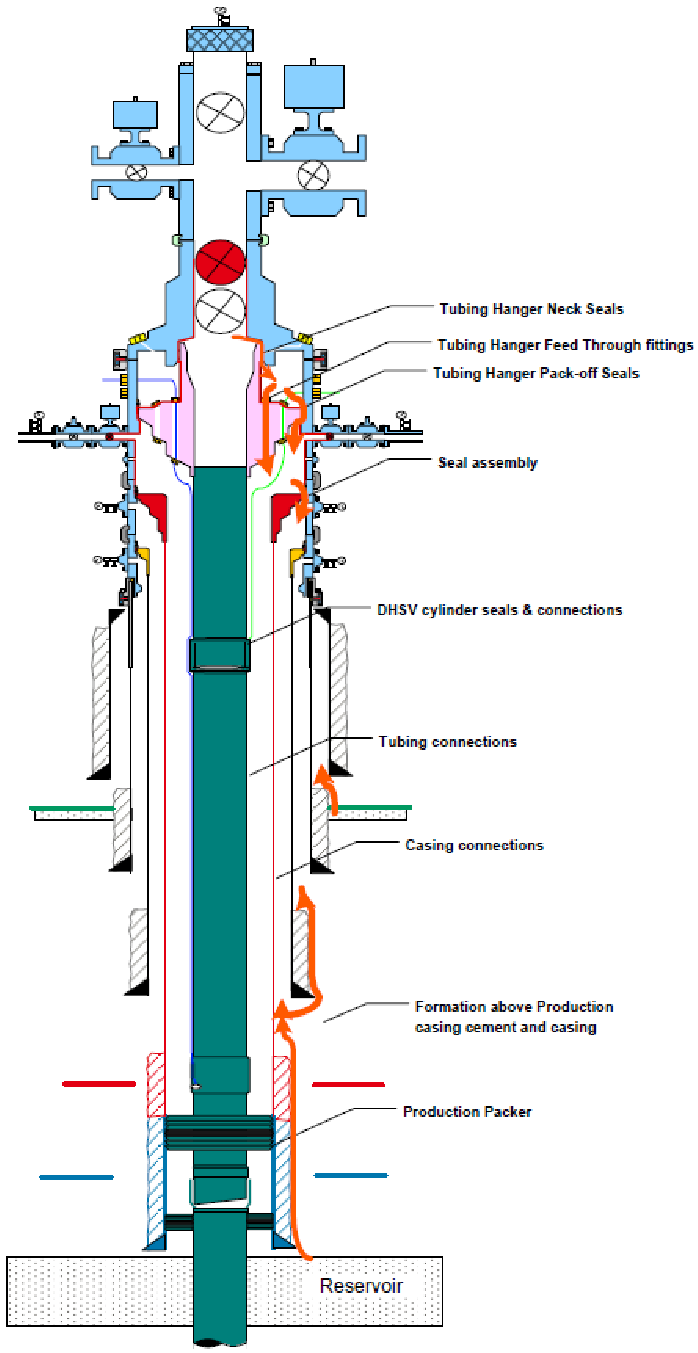
Sustained Casing Pressure (SCP)

Any deviations from the expected annulus pressure behavior that is not intentionally applied or from thermal expansion can indicate the presence of sustained casing pressure (SCP). The pressure builds back up when bled, and indicates communication to formation or another annulus through a defective or failed barrier.

SCP can arise from a variety of causes, including degradation or failure of well barriers, and can occur throughout the lifetime of a well. SCP may be the result of leaks e.g. through casing or tubing, through cement or wellhead seals, or directly from the reservoir.

Figure 9 illustrates some of the potential leak paths that can be present in a well (117- Norwegian Oil and Gas Recommended Guidelines for Well Integrity)

Figure 9 - Potential leak paths that may result in SCP (117- Norwegian Oil and Gas)



Appropriate monitoring and routines to aid early detection of SCP are an important part of the management of SCP. Monitoring over longer periods (e.g. months) and at a higher frequency are required in order to identify slow pressure buildups over time, since detecting the onset of SCP is difficult from monitoring over short periods. Therefore continuous remote monitoring of all accessible annuli is considered best practice, along with regular calibration, inspection and function testing of the monitoring equipment.

Bleed downs and top ups should be recorded to facilitate: correct interpretation of annulus pressure behavior; detection of foreign fluids; and annulus content is known.

The minimum information to be recorded is: annulus pressure before and after the activity; duration of the activity; the fluid type; volume introduced or removed from the annulus; and pressure behavior of tubing and other annuli.

Trapped Annular Pressure (TAP)

In some cases the annulus pressure is allowed to build due to thermally induced or sustained pressures (e.g. subsea wells) and is controlled only by venting to an open subsurface formation or entirely trapped by cemented casings. The effects of trapped annular pressure have to be considered in well design to prevent excessive pressure buildup and its impact on well integrity.

3.4.2 Case Study of Sustained Casing Pressure in CO_2 Injection Wells (Hongjun Zhu et al, 2013)

Jilin oilfield in northeast China is a mature field in a late period of development. To boost production, operator China National Petroleum Corp. has initiated CO_2 EOR injection. Many older wells, including producing and injection wells have been converted to CO_2 injection service.

Many problems arose during CO_2 injection, with Sustained Casing Pressure (SCP) being the most prominent. Results from pressure bleed-down tests followed by pressure build-up tests showed most of the wells to have SCP problems. Results indicate that SCP in some wells is so serious that the casing head pressure nearly equals surface tubing pressure.

Figure 10 shows the possible CO_2 leakage paths and Figure 11 the casing program in Jilin oilfield.

Figure 10 - Potential CO_2 Leakage Paths (Zhu et al, 2013)

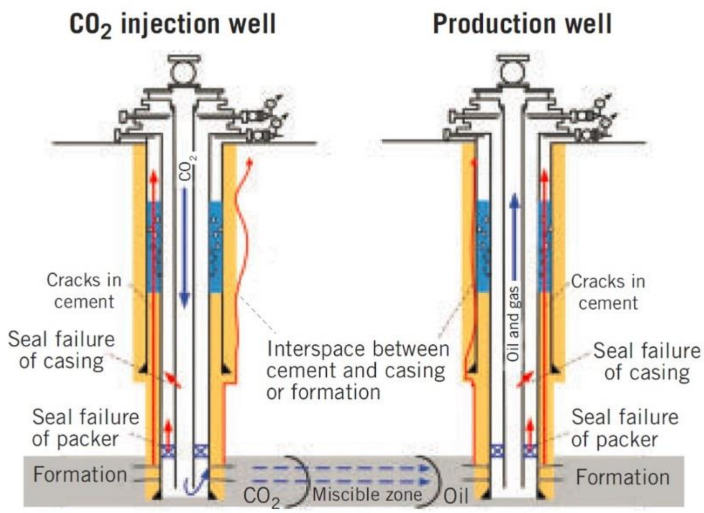
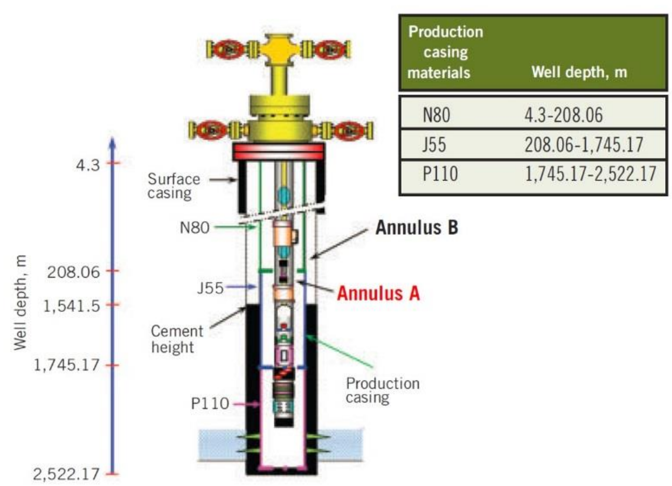


Figure 11 - Casing Program in Jilin Field, China (Zhu et al, 2013)



The authors have discussed the major causes for SCP and loss of well integrity as follows:

<u>*Tubing/Casing Leaks*</u>

Three conditions can cause leakage in tubing and casing: deformation of tubulars, poor thread sealing and corrosion.

- *During production, tubular goods will encounter several working conditions. Four effects rise from the change of temperature and pressure in different working conditions: piston effect (length changes), spiral effect (pressure on the two ends of the tubing that exceeds buckling pressure), expansion effect (differential pressure inside and outside of the columns), and temperature effect (temperature changes).*

- *The four effects directly result in the deformation of pipe strings, further affecting the pipe string's strength and packer's sealing. Which effect causes the greatest impact depends on the specific working condition. If all four effects occur simultaneously, the total change in string length is the sum of changing lengths induced by the four effects.*

- *Erosion on tubing joints is a primary factor leading to poor thread sealing. With high velocity fluid flow through the "J" region, which exists in the middle of the API thread, the change of the flow field causes local eddy and pressure fluctuations, weakening the thread strength. In addition, if there are installation defects, a gap may open between the two sides of the thread engagement surface, providing channels for gas migration.*

- *The corrosive effects of CO_2 are well known. The operator chose three grades of casing (P110, N80 and J55) used in CO_2 injection wells to observe the corrosion of steel by supercritical CO_2 and the laboratory testing results showed that the corrosion rate in gas phase to be much lower than in the liquid phase. P110 showed the best corrosion resistance followed by N80. A scanning electron microscope was used to observe the corrosion products more closely. The corrosion products accumulate less in gas phase than in the liquid phase and the corrosion product film was smoother and higher in density which can reduce the corrosion rate. After corroding in liquid phase, however, its corrosion product film is so loose, that it cannot prevent corrosion (Zhu et al, 2013). The laboratory testing results indicate that keeping the CO_2 in the gas phase while in contact with the casing string will reduce the corrosion rate.*

<u>Poor Cement Quality</u>

- *Gas migration during cementing is another cause of SCP. During hydration, cement goes through a physical state in which it does not behave as fluid or solid. In this transition stage, the cement plug has no capacity to transmit the entire hydrostatic pressure, resulting in gas migration through the cement column.*

- *Factors for a good primary cement job include: good mud displacement and mud properties rheology, control of fluid and filtrate losses. Severe dehydration may lead to reduction of the pressure in the cement column below the hydrostatic, and lead to upward gas flow.*

- *The cement sheath is easily damaged from pressure or temperature changes caused by production operations, such as CO_2 injection, gas lift, pressure testing, hydraulic stimulation etc. These operations cause expansion of the cement sheath, resulting in the separation of the casing and the cement (Ravi et al, 2002, Albawi, 2013).*

- *The corrosion of cement was also tested experimentally. After corrosion in gas phase, the original flake structure changed to crystal and fine granules, with the spectrum energy analysis indicating that the corrosion products being carbon, oxygen and calcium. The conversion of Portland cement by CO_2 to soluble materials like $CaCO_3$ has been widely tested experimentally (Kutchko, Strazisar et al, 2007, 2008). A detailed discussion of the chemical reactions and conversion products are found in Section 4.4.*

<u>Packer Failure</u>

- *Packers are set to operate successfully under a certain pressure differential. Under certain operating and reservoir conditions, when this pressure differential is exceeded, a packer failure may occur.*

- *Corrosion is another reason for packer failure. Hydrogenated nitrile-butadiene rubber is the core component of the packer. A set of tests evaluated the corrosion characteristics of rubber in gas and liquid phases. Results showed that the tensile strength decreases in both the gas and liquid phases, with a more severe trend in the liquid phase than in the gas phase (Zhu et al, 2013).*

- *Rigless intervention measures to address SCP problems include pumping sealant materials down the annulus and seal the leak at the leakage depth. Companies providing these services include CHEMIX (CaseGuard 2.2™) 2016 and WellCem (ThermaSet™), 2016. These techniques have been successful in remediating SCP problems (annular gas migration through cement) in different areas of the world including the North Slope of Alaska, North Sea and Kazakhstan. CaseGuard 2.2 is a Cesium Formate (CeS) heavy brine (specific gravity of 2.2 (18.36 pounds per gallon) and has been successfully applied in jobs in the KPO Karachanganak Field, Kazakhstan, while the ThermaSet (a polymer resin system) has been successful in jobs in the North Sea (Sanabria et al, 2016).*

3.4.3 Natural Gas Storage Failure Incidents **(*Syed*, 2017)**

As stated earlier, the primary purpose of underground gas storage is to provide a buffer between a relatively constant supply and a variable demand for gas. Other important factors to consider include:

- *Verification of inventory – how much gas can be stored as a function of pressure and sometimes time. For depleted gas reservoirs, need to establish a top pressure above discovery for storage, while aquifer storage requires gas injection above initial value to displace the water when creating the reservoir*

- *Retention of migration – requires a monitoring system to verify where the gas is residing and ensure that losses are not occurring*

- *Assurance of deliverability – ability to develop and maintain a specified gas deliverability rate. Generally the deliverability rate is keyed to reservoir pressure and inventory with a ~ 5% decline/year in deliverability. Options to increase deliverability include the use of horizontal wells and hydraulic fracturing stimulation*

Lessons learned from natural gas storage failure incidents and that may be applicable to CO_2 storage is given below:

<u>*Yaggy Incident*</u>

On January 17/18, 2001, natural gas escaped and migrated laterally more than 8 km, intercepted old abandoned wellbores (that were used earlier as brine wells) and caused explosions in Hutchinson, KS. There were two fatalities and a release of 143 MMcf (4.1 million m^3) of natural gas. The cause was determined to be casing damaged during re-drilling of an old, cemented wellbore during its conversion from propane to natural gas storage.

<u>*Moss Bluff Cavern Storage*</u>

On August 19, 2004, a wellhead fire and explosion occurred at Market Hub Partners Moss Bluff storage facility in Liberty County, TX. The fire self-extinguished, BOPE was installed and the well brought under control on August 26, 2004. About 6 billion cubic feet – bcf (170 million m^3) was released as CO_2 and not as CH_4 due to combustion from explosion and subsequent fire. Cavern was operating in "de-brining" mode (that is, brine is extracted as natural gas is injected) prior to explosion. Cause of explosion was determined to be as a result of parted casing (well string) inside the cavern. When the brine reached the separation point in the casing, pressurized gas entered the casing string and was brought to surface. Although the wellhead assembly closed properly, the loading resulting from the rapid change in flow rate caused the casing to fail. The casing was weakened from wall loss due to internal corrosion, although it was only 4 years old.

Aliso Canyon Incident

On October 23, 2015 the largest methane leak in U.S. (estimated 4.62 bcf – 131 million m^3) occurred at SoCalGas Well SS-25 in Aliso Canyon Gas Storage Facility, LA County, CA. Aliso Canyon facility has 115 storage injection wells with spud ages ranging from 1939 to 2014 with a total storage capacity of 86 bcf (2.1 billion m^3).

Well SS-25 was originally drilled and completed as a producer in April 1954, sidetracked at 3,900 feet (1189 m) due to hole problems and completed at ~ 8,950 feet (~ 2730 m) (sandstone) as a gas producer. It was converted to gas storage in May 1973 and operated in natural gas pressure cycling through both casing (which was un-cemented in critical upper sections) and tubing, providing only a single protection barrier. The leak is suspected to have occurred at a depth of 440 feet (134 m) in the 7 inch (17.78 cm) casing in the un-cemented upper part of the casing. After repeated top kill attempts failed, a relief well was drilled and the well cemented and sealed on February 17, 2016.

Many of the original wells had downhole safety valves (DHSVs) for pressure control. Later the DHSVs were removed and not replaced, or replaced with subsurface sliding sleeve valves (SSVs) to permit well maintenance and fluid circulation between tubing and tubing-casing annulus. No DHSVs were installed in wells drilled since 1980 due to reliability concerns. Wells are considered capable of casing production if SSVs in tubing allowed gas flow to casing or had no tubing. Well SS-25 was monitored for gas leaks, annually in recent years, or sporadically or biannually in earlier years. Also, there is no record of corrosion logs to verify metal loss having been run in these wells.

Until early 2017, federal regulation did not provide operational, safety, or environmental standards for the subsurface portions of underground natural gas storage facilities (wells, reservoirs, caverns).

Responding in part to the Aliso Canyon incident that began in October 2015, the U.S. Congress passed The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (PIPES Act). PHMSA (Pipeline and Hazardous Materials Safety Administration) is delegated under this Act to develop safety standards relating to UGS facilities and an Interim Final Rule (IFR) incorporating two API Recommended Practices (API RP 1170 and API RP 1171) was issued effective January 18, 2017.

US states have regulated gas storage facilities since the beginning of the 20th century. Several US states have dedicated regulatory frameworks for gas storage (especially common in states with significant cavern storage capacity), but in the majority of states with oil and gas development, the states' core well integrity rules (concerning drilling, casing, cementing, and related topics) apply to gas storage facilities as well. States are increasingly considering the development of stand- alone gas storage facility rules.

Since gas storage acts as a buffer to balance supply and demand, it requires the majority of the stored gas to be withdrawn if needed. Therefore, gas storage occurs mostly into geometrically constrained reservoirs, i.e. depleted oil and gas reservoirs and salt caverns. This is contrary to the purpose of large-scale CO_2 geological storage, which is long-term and mainly targeting saline aquifers with large areal extent. On the other hand, surface facilities, i.e. compression plants and pipelines will probably be very similar in natural gas and CO_2 storage operations. According to Perry (2005) the following five technologies, mainly associated with gas storage in saline aquifers, could be relevant for CO_2 geological storage:

- *Application of all available techniques*
- *Observation wells*
- *Pump testing techniques*
- *Assessment of cap rock sealing, and*
- *Surface monitoring*

Generally, it is expected that reservoir pressures associated with CO_2 storage in depleted oil or gas fields will not exceed initial field pressures to prevent negative impacts on reservoir and cap-rock integrity. The same was true for some time in gas storage operations. However, according to Bruno et al (1998), the pressure, and consequently the storage capacity, in gas storage reservoirs can safely be increased, if the geomechanical behavior of the reservoir and overburden is well characterized. In the Settala storage field in Italy, exceeding the initial reservoir pressure by 7% (delta pressuring) resulted in a 45% increase in storage capacity (Cooper, C., 2009). In this case, careful testing of operating pressures and a comprehensive monitoring program are critical to ensure containment of the stored gas (IEAGHG, 2010).

4.0 CARBON DIOXIDE CORROSION

Corrosion Effects of CO_2

The process of aqueous CO_2 corrosion and the corrosion rate on steels are well known. Gaseous or supercritical dry CO_2 is not corrosive (ASM, 1994 and Hesjevik et al, 2003), however, CO_2 in combination with water creates an acidic environment that causes corrosion of steel products in wellheads, casing and completion strings. CO_2 may be corrosive or noncorrosive depending upon the materials employed, temperature at the contact surface, water vapor concentration, CO_2 partial pressure and velocity effects.

Corrosion Mechanism

Different forms of corrosion can occur on contact with CO_2 acid water: General corrosion and Localized corrosion (Cailly et al, 2005).

General corrosion refers to corrosion dominated by uniform dissolution and thinning. Carbon steels undergo this form of corrosion when in contact with CO_2 acidified water. The CO_2 corrosion rate on carbon steels has been considerably studied in the past and numerical models taking into account temperature and CO_2 partial pressure can predict it. Design over-thickness and injection of corrosion inhibitors are the basic means to prevent this kind of corrosion. The best way is to use corrosion-resistant alloys (CRA), but these materials are very expensive compared to carbon steels (see Table 5, Bellarby, 2009).

Localized corrosion occurs when the corrosion damage produced is localized rather than being uniformly spread over the exposed metal surface, making this form of attack more difficult to deal with. The forms of localized corrosion are mainly pitting and crevice formation, but crevices are mostly created in presence of H_2S rather than CO_2. Pitting is one of the most insidious forms of corrosion, since pits are generally small and not easy to detect. It can cause failure by perforation although very little weight loss has occurred. The most common cause of pitting corrosion on CRAs is contact with chlorides, with carbon steels being less sensitive to chlorides than alloys.

The corrosion process in carbon steel includes (Zhang and Kermen, 2013, Nygaard, 2010):

$$CO_2 + H_2O \rightarrow H^+ + HCO_3^-$$

$$2(H^+ + HCO_3^-) + Fe\ (s) \rightarrow Fe^{2+} + 2HCO_3^- + H_2$$

$$Fe\ (s) + 2H^+\ (aq) \rightarrow Fe^{2+}\ (aq) + H_2\ (g)$$

At the steel/liquid interface, an anodic reaction takes place and iron atoms are oxidized as cations, and in the meantime, a cathodic reaction takes place and protons are reduced. Bicarbonate and carbonate anions can react with ferrous ions to form an iron carbonate film and the solid iron dissolves into iron ions in solution to create a corroded surface on the steel. The basic requirement for this reaction to occur is water.

Carbon dioxide or sweet corrosion attacks metals due to the acidic nature of dissolved carbon dioxide (carbonic acid). The acidity (pH) of the solution will depend on the partial pressure of the carbon dioxide. For the same pH, the weak carbonic acid is more corrosive than strong acids (e.g. hydrochloric acid), as carbonic acid can rapidly dissociate at the metal surface to provide a steady supply of the hydrogen ions needed at the cathode. Salinity, especially bicarbonate, acts to buffer the pH. In addition to the buffering effect of dissolved solids, semi-protective scales or films have a significant role in reducing corrosion rates. The formation and removal of these scales is temperature dependent and the highest corrosion rate for carbon steel is at around 200 °F (93 °C).

When CO_2 is used for EOR, generally water alternated with CO_2 gas (WAG) or recycled CO_2 is injected. In capture and sequestration projects, dry CO_2 (with CO_2 purity above 95%) will be injected in the supercritical state and the corrosion risk is low and therefore, corrosion problems are not expected to be any more severe for CO_2 storage as compared to regular CO_2 EOR operations (Nygaard, 2010). However, the corrosion rate will increase if the injected stream comes into contact with water. Possible water sources may include: connate water in the injection zone, free water in the cement or free water resulting from capillary condensation (Kolenberg et al. 2012).

After the injection period, during the long-term storage phase, the supercritical CO_2 can be hydrated with water present in the reservoir and wet CO_2 and the resulting acid brine can reach the well leading to potential degradation of the cement sheath protecting the casing.

The effect of CO_2 on cement in wells is presented in Section 4.4 and in Appendix 5 – Cementing.

4.1 CORROSION CONTROL IN CO_2 INJECTION WELLS

CO_2 corrosion depends on several factors (Zhang and Kermen/CATO2, 2013, Cailly et al, 2005):

- *Presence of water - an oil-wet system protects steel from corrosion*
- *CO_2 content – if the partial pressure exceeds 2 bar (29 psi), and significant corrosion occurs in a water wet environment (Partial pressure = total pressure x volume fraction of CO_2 gas component)*

- *H_2S content – even in low concentrations in combination with CO_2 , this mixture can cause severe corrosion, leading to sulfide stress cracking*
- *Oxygen content and content of other oxidizing agents*
- *Temperature – when above 150 °C (302 °F) a dramatic increase in corrosion rate occurs (Zhang and Kermen, CATO2, 2013)*
- *Pressure – generally the corrosion reaction accelerates with increasing pressure*
- *pH*
- *Chloride concentration – chloride enhances corrosion*
- *Condensing conditions – if water drops out of the gas stream, corrosion will occur*
- *Velocity conditions*

In general corrosion can be mitigated or controlled by either selecting materials that are resistant to the service environment or by the use of chemical inhibition. The primary factors associated with these two corrosion strategies as they apply to down-hole tubular are summarized below (Sorem et al, 2008):

Chemical Inhibition: In this approach, chemical inhibitors can be selected and qualified for either continuous or batch injection. Continuous injection can be carried out by installing a port at the bottom of the tubing and injecting inhibitor from a surface tank at the surface down the annulus, through the tubing injection port and into the injection stream inside the tubing. A downside of continuous injection is that significant corrosion can occur at the injection point as a result of the high shear generated at this point, and may not be the preferred option for CO_2 injection wells. With the batch method, the tubing volume is filled with inhibitor or squeezed into the formation for a period of time before it is flushed out. A downside of this method is the need to shut in the well to carry out the batch injection and the resulting downtime in injection operations.

Corrosion Resistant Materials: The second and more common approach for corrosion control is to specify materials that will resist the corrosive environment. Materials can generally be selected that will withstand the corrosive environment for the lifetime of the well, but in other cases, less resistant (and less expensive) materials are selected that will withstand the service environment for a limited period of time and subsequently require periodic replacement. With the latter method, the failure mechanism and the duration of service must be well known, and the inspection carried out at a sufficient frequency so that replacement can be carried out prior to losing the integrity of the down-hole tubular (See Sections 2.1.8, 4.3 and 4.4)

To mitigate corrosion, techniques typically used in addition to that listed above include:

1. *Correct cement placement. To minimize contact between carbonic acid and the steel casing, great care is used to assure that the cement, used to bond it to the formation, is adequately distributed along its entire axis. This requires: careful removal of residual drilling mud from the hole; use of centralizers to center the casing string in the borehole; and, full circulation of the cement returns to the surface.*

With a well formed cement sheath in place, the rate of permeation of corrosive material is reduced significantly.

- *Placement of acid resistant cements in zones susceptible to cement carbonation. As appropriate, operators will incorporate specialty cements or specialty slurry designs adjacent to and above the CO_2 injection zone. These cements are more resistant to CO_2 attack and hence dramatically reduce the rate of CO_2 degradation.*

- *Cathodic protection of the casing string. Operators employ both impressed and passive current techniques on the casing string to counteract naturally occurring galvanic action, which leads to corrosion. Both methods are used widely in many industrial applications.*

- *After completing the well, a biocide/corrosion inhibitor laden fluid is placed in the annular space between the casing and tubing string to further suppress any corrosive tendency.*

It is important to assess the lifetime cost and operational impact of the selected corrosion control techniques and to history match the field data (including well hydraulics performance) with the laboratory derived predictions as the project implementation proceeds. An integrated corrosion engineering approach should be utilized to optimize the life-cycle material and corrosion mitigation costs, with the potential to allow well designs that take advantage of carbon steel tubing in conjunction with CRA liners, with significant cost savings while overcoming injection capacity limitations.

The technological advancement made by the CO_2 EOR industry in the U.S. is summarized in Contek/API's 2008 report as follows:

- *Corrosion resistant materials, such as stainless and alloy steels (e.g., 316 SS, nickel, Monel, CRA), for piping and metal component trim. Use of corrosion protection of the casing string via impressed and passive currents and chemically inhibited (e.g., oxygen, biocide, corrosion inhibitor) fluid in the casing tubing annulus*

- *Use of special procedures for handling and installing production tubing to provide tight seals between adjacent tubing joints and eliminate coating or liner damage*

- *Use of tubing and casing leak detection methods and repair techniques, using both resin and cement squeeze techniques. Also the insertion of fiberglass and steel liners.*

- *Formulation and implementation of criteria unique to well sites in or near populated areas, incorporating fencing, monitoring and atmospheric dispersion monitoring elements to protect public safety.*

4.2 CORROSION MONITORING OF CO_2 INJECTION WELLS

Corrosion rates should be monitored throughout a CO_2 injection project. Corrosion rates are commonly reported in mils per year (mpy) or millimeters per year (mm/yr) of penetration or metal loss where 1 mil is equal to a thousandth of an inch (USEPA, 2013). Target corrosion rates of less one mpy (0.025 mm/y) or less are common in wells used in the oil industry, with NORSOK recommending a limit of 0.10 mm/y (CATO, 2013). These rates are difficult to achieve, unless the CO_2 is dry. From experiments with carbon steel, corrosion rates higher than 10 mm/y have been observed in a wet CO_2 environment. Laboratory tests from Valourec indicate that the target corrosion rate might not even be achievable with 13Cr casing, as rates higher than 1 mm/y have been reported under certain conditions (Nagelhout, et al, 2009).

At a moderate pressure of 1.00 MPa (145 psi), the corrosion rate of X65 pipeline steel is independent of temperature from 50^0 C to 130^0 C (120^0 F to 270^0 F) (Sim et al, 2014). Increasing water concentration, on the other hand, causes a significant increase in corrosion for steel. For example, at a pressure of 8 MPa (1,160 psi) and a temperature of 40^0 C (104^0 F), increasing the water concentration in supercritical CO_2 from 1,000 to 10,000 parts per million (ppm) causes the corrosion rate of steel to increase by 87% (Sim et al, 2014). Similarly, for carbon steel in aqueous CO_2 solutions at 25^0 C (77^0 F), increasing the CO_2 partial pressure from 0.1 MPa (14.5 psi) to 1 MPa (145 psi) produces a corrosion rate increase of about 450% (DeBerry et al, 1979). Other researchers (Cailly et al, 2005) have reported that corrosion rate on carbon steel increases from 25 mm/y (1000 mils/y) at 65^0 C (149^0 F) and 1 MPa (145 psi) CO_2 pressure to 250 mm/y (10,000 mils/y) at 82^0 C (179.6^0 F) and 16 MPa (2,320 psi) CO_2 pressure (Cailly et al, 2005).

The corrosion rate limit refers to general corrosion of the metal, which is the uniform thinning of the metal. A low corrosion rate may not be acceptable if localized corrosion (such as pitting) is occurring, whereas a higher rate with a general area metal loss may be, in some cases, a less serious problem. Corrosion monitoring tools currently used fall into three categories: corrosion coupons, corrosion loops and casing inspection logs.

Corrosion coupons

A coupon is a small, carefully manufactured piece of metal (such as a strip or a ring), made of the same material (or as close as possible) as the casing or tubing, and placed in an appropriate location in the injection well to measure corrosion.

It is weighed, placed in the well for a period of time, recovered and weighed again, and the difference gives the weight loss and corrosion rate. The coupon is placed and recovered by wireline (Jaske et al, 1995).

Corrosion loops

A corrosion loop is a section of tubing that is valved so that some of the injection stream is passed through a small pipe running parallel to the injection pipe at the surface of the well. Since the composition of the pipe is the same as the well's tubing, it acts as a small-scale version of the well, except that it has a smaller diameter and its temperature is lower due to its shallower depth (USEPA, 2013). Measurements of the corrosion rate may be higher or lower than actual downhole corrosion rates by this method. This method may not yield accurate data in cases where the injected CO_2 is in a dry supercritical state (CATO, 2013).

Casing inspection logs

Casing inspection logs are run to measure the casing thickness and integrity, cross-sectional wall loss, borehole/casing/tubing radius, pitting etc. to monitor corrosion effects on downhole tubulars. There are several different techniques and tools available today, and these are generally run on wireline.

Techniques include: electromagnetic thickness logs run on electromagnetic induction tools that measure both the internal diameter and the wall thickness and evaluate both internal and external pipe integrity; magnetic flux that utilize magnetic flux leakage technology to record the location, extent and severity of corrosion and metal loss in tubulars; ultrasonic corrosion logs that use a high transducer frequency to measure anomalies in the tubulars (also run in conjunction with ultrasonic cement bond logs); and electrochemical sensors (electrochemical noise measurements – (ENM) and linear polarization resistance – (LPR) have been used in downhole corrosion monitoring in oil wells – except gas wells in Saudi Aramco (system operates at high temperatures (> 150 °C (302 °F)) (CATO, 2013). The use of multi-finger (24-arm or 40-arm) caliper logs that measure the internal radius of the casing/tubing is less desirable as pitting corrosion is difficult to determine and there is a potential for damage to the casing/tubing from the logging tool. Downhole corrosion monitoring systems have also been widely used in different fields in the North Slope of Alaska.

4.3 MATERIALS OF CONSTRUCTION FOR CO_2 WELLS

Material selection for CO_2 injection wells depends on several factors like high strength requirements combined with high corrosion resistance of the material. A chemical analysis of the reservoir fluids is generally required for evaluation of the corrosive components such as H_2S, CO_2 and chlorides. Other components such as temperature and pressure profiles and stresses on the tubulars should also be considered. When assessing wells or selecting materials for CO_2 injection wells, one has to consider that the wells will be in contact with wet CO_2, especially in the deeper section of the well (CATO2, 2013).

4.3.1 Steel Types

Some steel types used for well construction are listed below, with increasing corrosion resistance (CATO2, 2013):

- ***Carbon steel:*** *Contains less than 2.1% carbon in their chemical composition. Most commonly used grades uses are J-55/K-55, L-80, N-80 and P-110. These grades are susceptible to CO_2 corrosion. J-55 and K-55 are generally used for surface casing.*

- ***Martensitic stainless/corrosion resistant steel:*** *Contains at least 11.5% chromium such as 13Cr and 17Cr. Adding chromium to the steel promotes the strength and adherence of the corrosion product to the steel surface. For low to moderate temperature environments (less than 300 °F (149 °C)) containing CO_2, little or no H_2S and low chlorides, 13Cr has become the standard tubing metallurgy and L80 13Cr is included as an API specification. Most wells in the Netherlands are completed with 13Cr tubing. At high temperatures (above 300 °F (149 °C)) the use of 13Cr tubing becomes border-line. Modified (2Mo-5Ni) 13Cr alloys and duplex steels provide higher temperature carbon dioxide corrosion resistance as well as increasing resistance to H_2S with 15Cr acceptable to 390 °F (199 °C). In some instances, as in the presence of strong acids, martensitic steels provide superior corrosion resistance than duplex steels. Martensitic steels are not very corrosion resistant and are susceptible to sulfide stress cracking (SSC), which makes them ineffective in H_2S environments. On the other hand, they are extremely resistant to chloride stress cracking (CSC).*

- ***Super martensitic stainless steel:*** *Contains less carbon and more nickel and molybdenum, and is more resistant to corrosion than normal martensitic 13Cr steel. Super 13Cr is reported to be 5 to 44 times more resistant to CO_2 injection depending on the pressure and temperature conditions (SINTEF, 2007 in Cato2, 2013).*

- ***Ferritic-austenitic steel alloy:*** *Also known as duplex steel, it contains chromium, manganese, nickel, vanadium and molybdenum. It is a mixture of ferritic and austenitic steel, much stronger than austenitic steel and more resistive to corrosion pitting and stress cracking than regular austenitic steel. Have low carbon content, high chromium (at least 20% and molybdenum (3-5%) content and low nickel content (< 5%) compared to austenitic steel). 22Cr is the most frequently used steel in the oil industry. Super duplex steel (25Cr) contains significantly more nickel and molybdenum.*

- ***Austenitic/super austenitic steel alloys:*** *These consist mostly of nickel and cobalt alloys. Austenitic steels contain at least 16% chromium and 10% nickel-manganese combination. Common austenitic steels such CrNi18-9 or CrNiMo17-12-2 provide average corrosion resistance and are susceptible to stress cracking caused by both sulfides and chlorides. On the other hand super-austenitic steel alloys are resistant to stress cracking and provide very high overall corrosion resistance. Super-austenitic steel alloys contain very high (+30%) amounts of nickel and high molybdenum content (+6%) to protect from chloride pitting and crevice corrosion. Super-austenitic steels include alloys such as Inconel 625, Hastelloy C-22 and Hastelloy C-276.*

Other factors to consider should include material capabilities for low temperatures (brittle materials may not be adequate protection for a CO_2 leak) and oxygen-related corrosion impacts.

4.3.2 Corrosion resistant alloys (CRA)

Corrosion resistant alloys are divided into groups 1,2,3,4 based on their technical specifications. It should be noted that there are no industry standards for Group 2-4 alloys and the standard for well construction material – API 5CT, only covers 13Cr steel, which is a grade in Group 1.

Group 1: Martensitic and Martensitic-Ferritic Stainless Steel

These are the simplest and most commonly used CRAs in the oil industry. Group 1 alloys are available in the yield strength range of 80-110 kpsi.

Group 2: Duplex Stainless Steel

Duplex stainless steel offers several advantages over martensitic alloys. Have higher resistance to CSC (chloride stress cracking) and also have good resistance to crevice and pitting corrosion. They are available in a wide range of yield strength between 65 kpsi to 140 kpsi, but as mentioned earlier, due to the absence of a standard that covers such materials, they have to be carefully evaluated for chemical composition, heat treatment, hardness, micro-structure and impact properties.

Group 3 and 4 Alloys

For these alloys, the amount of alloying increases up to eight times more Ni and up to three times more Mo while maintaining the same Cr content. These alloys provide improved corrosion resistance to H_2S, CO_2 and chlorides. In addition to chemical and metallurgical evaluations, corrosion testing (Slow Strain Rate Test – SSRT) is also recommended to verify that the materials will meet the expected performance.

Use of corrosion resistant alloy (CRA) casings/liners etc. in lieu of carbon steel casing provide enhanced corrosion protection for severe CO_2 service but may have the downside of increased costs and with decreased injection capability (Syed, 2010).

Table 4 gives a summary of the material characteristics for tubulars (CATO2, 2013)

Table 4 – Material characteristics for tubulars (CATO2, 2013)

Some Prospective Alloys for Hot Well Tubulars						
Alloy	Major Alloying Constituents, wt%			General Corrosion Resistance(1)	Cracking Resistance	
	Cr	Ni	Mo		SSC	CSC
CrNi18-9	18-20	8-10.5	-	F	S	S
CrNiMo17-12-2	16-18	10-14	2-3	F	S	S
Cr13	11.5-13.5	0.75	-	S	S	R
Cr17	16-18	0.75	-	F	S	R
Super Cr13	11.5-13.5	5	2	F	F	R
Duplex SS (Cr 22)	22	5	3	G	S	G
Superduplex (Cr	25	7	4	G	G	G
25)	21.5	42	3	G	R	R
Incoloy 825	21.5	min. 58	9	R	R	R
Inconel 625	22	26	5	G	R	R
Haynes 20 Mod	22	56	13	R	R	R
Hastelloy C-22	16	57	16	R	R	R
Hastelloy C-276	20	35	2.5	G	R	R
Carpenter 20 Cb						
SS = Stainless / Corrosion Resistant Steel				G = Good F = Fair S = Susceptible R = Resistant		

Installing corrosion-resistant tubing is expensive and Table 5 gives the approximate relative cost of different tubing options.

Table 5 - Relative Costs of Tubing Materials (Bellarby, 2009)

Tubing	**Approximate Cost Relative to Carbon Steel**
L80 Carbon Steel	1
L80 1% Cr	1.05
Coated (e.g. phenolic epoxy) carbon steel	2
Fiberglass lined carbon steel tubing	3.5
L80 13Cr	3
Modified 13Cr steel (2Mo-5Ni)	5
22Cr duplex	8
25Cr duplex	10
2550 or 2035	20+
Titanium	10-20

4.3.3 Material Selection Guidelines for CO_2 EOR Wells

An excellent example of the evolution in materials technology for CO_2 injection systems has been presented by Newton, 1984 for the SACROC Unit.

For the dry side of the CO_2 supply system, corrosion has been minimal, as expected, since it contains less than 50 ppm H_2O. (Dry side, here, refers to the CO_2 field gas distribution system upstream of any piping exposed to both CO_2 and water flows). On the wet side, however, that is for those parts exposed to both CO_2 and water, corrosion concerns have to be addressed:

- *Meter runs, initially constructed of plastic coated carbon steel piping and valves with plastic coated carbon steel bodies with 316 SS trim were subject to severe corrosion at any point of coating damage, particularly at flange faces. Where 316 SS was used, no corrosion was observed. Meter runs are now constructed entirely of 316 SS pipe and valving.*

- *Initially, injection wellheads were equipped with 410 SS wellheads and 410 SS valves. They were subject to severe pitting type corrosion that occurred primarily under deposits from settled suspended matter contained in the injection water. Plastic coating the 410 SS wellheads and valve bodies and changing the gates and seats to 316 SS prolonged the life of many of the wellheads. A replacement program using all 316 SS wellheads was eventually undertaken.*

- *Injection wells were initially equipped using primarily 2 7/8 inch and 2 3/8 inch J-55 plastic coated tubing set on plastic coated double set packers. Epoxy-modified phenolic coating was most successful except where applied too thick (> 0.17 mm thick) as that resulted in blistering; powder applied epoxy-phenolics (8-16 mil in thickness) was the most resistant to mechanical damage and not subject to blistering. Tubing with this coating is now in use. The average service life for coated tubing was 50 months.*

- *Chevron also tested 6 tubing strings with polyethylene liners, and they all failed. The mechanism was attributed to CO_2 permeation of the liner, subsequent deterioration of the adhesive and collapse of the liner by pressure build-up (Smith et al, 2011). Up to 25% of the injection wells had tubing pulled and inspected each year due to tubing leaks or for workover purposes. The primary cause of failure was identified as mechanical damage occurring during: hauling, running and pulling of the tubing. Handling and installation procedures were modified to circumvent these problems.*

- *Unocal used plastic coated injection tubing in their Dollarhide Unit (WAG) but damage during field installation led to tubing corrosion problems and leaks at connections. After trying several approaches, they finally established the use of a modified 8-round coupling with Ryton coating on the threads and a seal ring. They also applied low-speed make-up of connections and rigorous helium testing of each connection to solve the leak problem.*

- *Texaco in a continuous CO_2 injection program (no WAG used), ran bare carbon steel tubing in CO_2 injection wells since the tubing would not be exposed to water and so no corrosion was expected.*

It can be expected that based on experience with CO_2 EOR projects successfully maintaining wellbore integrity, a similar outcome can be expected for CO_2 storage wells (See SACROC experience in Sections 4.3.3 and 4.4.1)

<u>*Corrosion Control and Elastomers*</u>

As a result of using corrosion resistant materials in a WAG injection well and associated piping and invoking operational practices to isolate CO_2 sources during water injection cycles, no additional corrosion control measures, such as corrosion inhibitor injection, are used in current CO_2 EOR field operations.

Additionally, by choosing appropriate elastomeric materials for packers and seals, such as internally coated hardened rubber (80-90 durometer) for packers and Teflon or nylon for seals, swelling has been circumvented.

A survey of operator experience by the New Mexico Petroleum Recovery Research Center has shown that in CO_2 EOR floods, because of the suite of corrosion control measures used, corrosion and surface facility problems that were anticipated prior to project start-up were essentially absent (Grigg et al, 1997). Other field experience also supports this same conclusion (Contek/API, 2008).

The data in Table 6 summarize the major mechanical completion components of a CO_2 EOR injection well and the current preferred materials of construction (MOC).

Table 6 - Materials of Construction (MOC) for CO_2 EOR Injection Well Components (Contek/API, 2008)

Component	**MOC**
Upstream Metering & Piping Runs	316 SS, Fiberglass
Christmas Tree (Trim)	316 SS, Nickel, Monel
Valve Packing and Seals	Teflon, Nylon
Wellhead (Trim)	316 SS, Nickel, Monel
Tubing Hanger	316 SS, Incoloy
Tubing	GRE lined carbon steel, IPC carbon steel, CRA
Tubing Joint Seals	Seal ring (GRE), Coated threads and collars (IPC)
ON/OFF Tool, Profile Nipple	Nickel plated wetted parts, 316 SS
Packers	Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts
Cements and Cement Additives	API cements and/or acid resistant specialty cements and additives in Appendix 5

The key points of the information in Table 6 are as follows:

- *In any wetted region, 316 SS is the metal of choice for valve trim, metal piping, etc. The corrosion resistant properties of stainless steels have been known for decades and their adaptation to oilfield use for CO_2 injection wells has largely been a matter of implementing existing technology. In selected cases, operators use fiberglass piping in upstream metering/piping runs.*

- *The same is true with elastomer and seal materials. Buna-N and Nitrile rubbers with an 80-90 durometer reading are widely used for packers, with Teflon and Nylon used for seals.*

- *Considerable effort has been devoted to the development of lined and coated tubing strings. Currently, both are used. Glass reinforced epoxy (GRE) lined tubing is composed of an internal fiberglass liner, or sleeve, bonded to the inside of a steel pipe. Internally plastic coated (IPC) tubing consists of a sprayed coating (phenolics, epoxies, urethanes or novolacs) to the inside of a steel pipe. Cement lined tubing has been tried but experienced collar (joint) leaks and was replaced with GRE lined tubing. The choice of tubing type appears to be dictated by operator experience and success in a given area.*

- *Tubing collar leaks have been one of the most common problems associated with WAG injection. Seal rings are commonly used for making up GRE lined tubing joints and the vendor is typically on-site during installation to assure quality. For IPC tubing, the coating typically extends over the threaded end of the joint and internally coated collars are used. For very large re-completion situations such as in the Salt Creek Field, Wyoming, field personnel have been trained to properly makeup tubing joints (Contek/API, 2008).*

- *Special procedures have been developed for handling, running, pressure- testing and installing the tubing to protect the internal coatings and connections. Helium test methods have proved quite successful for leak detection.*

- *In the tubing string metal parts such as the profile nipple and ON/OFF tool are nickel plated.*

- *For packers, nickel plating is used on all wetted parts and internally coated hardened rubber elastomers of 80-90 durometer strength (Buna-N) are used to circumvent CO_2 permeation.*

Because of the corrosive effects of carbonic acid H_2CO3, on metal components, induced by the alternating water and gas (WAG) injection cycles during CO_2 EOR operation, a significant fraction of scientific and technical work has been devoted to developing robust solutions to corrosion problems. Supplemental work has also been done on identifying and developing elastomeric materials for packers and seals that can withstand the solvent effects of supercritical CO_2 that induce swelling and degradation. Throughout this process, the underlying strategy of the industry has been to select materials based on their durability and corrosion resistance. Today, the material improvements presented in Table 6 above, as well as the use of special tubing handling and installation techniques, enables operators to routinely expect a tubular service life on the order of 20 to 25 years (Contek/API, 2008).

4.3.4 Material Selection Guidelines for CO_2 Storage Wells

For carbon sequestration wells, material selection depends on several factors like high strength requirements combined with high corrosion resistance of the selected material. A chemical analysis of the reservoir fluids will be required to evaluate the corrosive components such as H_2S, CO_2 and chlorides. Other components such as temperature and pressure profiles and stresses on the tubulars and cement design have also to be considered and that wells will be in contact with wet CO_2, especially in the deeper section of the wellbore. It is also important not to mix low grade metal seals with high grade tubing/casing material to avoid galvanic corrosion due to the difference in electric potential between the metals.

For injecting more than 95% pure CO_2 in wells the following guidelines may be used:

- *High pressure dry CO_2 does not corrode carbon steel even with the presence of small amounts of methane, nitrogen or other contaminants.*

- *13Cr and Super 13Cr show good performance in CO_2 environment. However, they are not applicable to temperatures higher than 150^0 C (302^0 F) and in combination with low amounts of H_2S (partial pressure > 1 bar (14.5 psi). 13Cr is also sensitive to O_2 corrosion. There is evidence that 13Cr alloy may be susceptible to pitting corrosion by salt water containing combinations of H_2s, CO_2 and O_2 at temperatures as low as 43^0 C (110^0 F). Severe corrosion in 13Cr tubing is also documented in K12-B pilot CCS site, even though conditions were within specifications (Zhang and Kermen/CATO2, 2013).*

- *Austenitic chrome-nickel alloys are susceptible to stress cracking due to both chlorides and sulfides. Their use is not recommended downhole.*

- *Duplex or super duplex steel (22Cr and 25Cr) is better suited at high temperatures and H_2S content, but can suffer severe corrosion during acid stimulation. It is therefore very important that when using this type not to acid wash the well. Duplex and super duplex steel is used in the Sleipner CO_2 storage project as casing and tubing respectively.*

- *Super austenitic alloys can also be considered if duplex steel cannot be used but are significantly more expensive.*

- *Another option is to use a lower grade steel with an internal coating. However, the coating may not be reliable and any breach may lead to rapid corrosion and deterioration of the steel and fragments of the coating may plug the perforations.*

- *Distinction should also be made between tubing and casing. Under the condition that the casing-tubing annulus will be continuously monitored for pressure buildup and potential CO_2 leakage, the casing can be carbon steel. Inaccessibility and remoteness to the site may require a more robust design, and if intervention will be difficult (offshore or populated areas) then CRA material will have to be used.*

- *The section of the casing below the packer will likely be subject to corrosion during the injection phase, and metals will be subject to corrosion after the injection phase (abandoned wells) due to contact of CO_2 with connate water.*

<u>International Experience</u>

Since 1996 Statoil (now Equinor) has been using amine solvents to remove the 9% CO_2 from the natural gas extracted from its offshore oil and gas sector. This is injected at about 1 million tonnes per year into a saline aquifer about 800 m below the seabed at Sleipner. A slightly smaller scale operation, 0.7 m tonnes/year, started up in 2006 at its Snøhvit field in the Barents Sea, injecting at 2,500 m depth.

For Sleipner, the tubing and exposed parts of the casing material selection was 25Cr duplex stainless steel. The injected gas is wet, essentially sweet but may contain up to 150 ppm H_2S and potentially 0.5 to 2% of organics (mostly CH4). Based on the saline aquifer depth, the conditions are expected to be within the safe operating envelope of 25Cr duplex, bearing in mind that there are no oxidizing acid species. Assessment of the fluid corrosivity concluded that the water in place would produce an acidic water film by wetting the metal surfaces (Baklid et al, 1996).

For Snøhvit the tubing was AISI 4140 with all completion components in 25Cr duplex stainless steel. The choice of 4140 is unusual and possibly driven by low temperature fracture considerations, but this is not certain. Like Sleipner, there would be no oxidizing acid components from this offshore source.

Key conclusions from the above CO_2 injection well experience are:

- *There is mixed performance of various polymeric linings at high pressure conditions. For deeper wells with > 350 bar (> 5,076 psi) at bottom hole conditions, linings would not be recommended due to blistering concerns (Smith et al, 2011).*

- *Whilst the WAG service typical of many USA wells results in particularly aggressive intermittent wet and dry service at the bottom of the well, the experience in several cases of corroded liners and casings is an indication that the conditions would be aggressive in CCS service if the aquifer flowed back to the wellbore over time (e.g. during prolonged shut-in, or at abandonment). Thus, selection of Corrosion Resistant Alloys (CRA) for the bottom of the well would be advised, following the approach taken by Statoil(now Equinor).*

- *High performance tubing connections are necessary to minimize the risk of the CO_2 leaks to the annulus.*

- *Materials selection used in existing CO_2 projects has often been 25Cr duplex stainless steel, but that may not be applicable where the components in the injected fluid stream are more acidic or oxidizing. 25Cr stainless steel will de-passivate at around a pH value of 2.0.*

4.4 CO_2 USE WITH CEMENTS AND CEMENTING PRACTICES

4.4.1 Background

Another potential area of concern for CO_2 injection well operators is the effect of CO_2 on cement in wells (Rutqvist, 2012). Carbon dioxide saturated with water deteriorates the cement used in wells. This deterioration can occur in cement that is adjacent to the well casing either in the annulus between the casing and rock or at the interface between the casing and cement. Therefore, the cement used in CO_2 injection wells must be able to resist the damaging effects of CO_2 because operational periods can last from 25 to 100 years and mandated safety periods that last much longer. For wells to reach these time objectives intact, using additives that make the cement more resistant to harm from CO_2 may be advantageous. Reaction of CO_2 with wellbore cement is slow in a well in which good construction practices and appropriate materials were used; in these cases CO_2 should not be a problem. Many old, abandoned wells – completed and shut-in using practices and cement acceptable at the time – are not suitable to use in long-term CO_2 storage systems. Leakage from abandoned wells has been identified as a significant risk in geologic storage of CO_2 (Oilfield Review, 2015)

Cementing is critical to the mechanical performance and integrity of a wellbore both in terms of its method of placement and cement formulation used. When CO_2 reacts with cement, the cement's strength is reduced and its permeability is increased. Primary cementing is done during regular drilling operations to support the casing and prevent fluid movement outside the casing (zonal isolation). Cement also protects the casing from corrosion and loads in deeper zones, prevents blowouts and seals off thief and lost circulation zones. The cement sheath is the first barrier around a wellbore that the CO_2 will encounter, and if the primary cement job is not successful it may lead to CO_2 leakage into shallower formations and a costly remedial cementing operation.

During the drilling phase, the cement sheath must withstand the continuous impact of the drill string, particularly with directional wells. During well completion when the drilling fluid is replaced by the relatively light weight completion fluid to minimize reservoir sand-face damage, the negative pressure differential can lead to de-bonding at the casing/cement and/or cement/formation interfaces. Also the cement sheath must withstand the stresses caused during perforating and stimulation/hydraulic fracturing operations.

Chemically, the degradation of Portland cements by carbonic acid is well known. CO_2 will react with Portland cement and convert the cement into a calcium carbonate material. The basic cement reactions of cement with CO_2 are outlined below. In cement chemistry notation, C is used to represent Calcium Oxide (CaO), S for Silica dioxide and H for water (H_2O). The abbreviations used in the formulas are:

C_3S - Tricalcium Silicate – Ca_3SiO_5, also called Alite

C_2S - Dicalcium Silicate – Ca_2SiO_4, also called Belite

CSH - Calcium Silicate Hydrate - A reaction product in a set cement matrix. The exact structure of C-S-H in cement is variable and the state of chemically and physically bound water in its structure is not precisely known, which is why "-" is used between C, S, and H.

H_2O - Water

CO_2 - Carbon Dioxide

$Ca(OH)_2$ - Calcium Hydroxide

$Ca(HCO_3)_2$ - Calcium Bicarbonate

CO_3^{-2} - Carbonate ion

H^+ - Hydrogen Ion

Cement Hydration

$Ca_3SiO_5 + H_2O \rightarrow 3CaO\ .\ 2SiO_2\ .\ 4\ H_2O + 3\ Ca\ (OH)_2$

$CaSiO_4 + H_2O \rightarrow C\text{-}S\text{-}H + Ca\ (OH)_2$

As above, the C-S-H in the second reaction is an abbreviation for $3CaO\ .\ 2SiO_2\ .\ 4H_2O$ although the exact ratio of $CaOSiO_2$ and H_2O is not precisely known.

Carbon Dioxide Reactions

$CO_2 + H_2O \rightarrow H_2CO_3 \rightarrow H^+ + HCO_3^-$

$HCO_3^- \rightarrow CO_3^{-2} + H^+$

$Ca(OH)_2 + H^+ + CO_3^{-2} \rightarrow CaCO_3 + H_2O$

$CO_2 + H_2O + CaCO_3 \rightarrow Ca(HCO_3)_2 + H_2O$

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

These reactions and systems have been researched for many years both in the laboratory and through comparison with field results of cores taken from CO_2 injection wells, or wells that were exposed to CO_2 floods. In evaluation of the results of much of the testing, while CO_2 will react with Portland cement, the long-term effects, and potential for loss of well seal do not appear to be at issue for properly designed and placed cements.

Kutchko, Strazisar et al (2007, 2008) performed extensive testing to evaluate the reactions of Portland cement with CO_2, and from the testing ultimately determined the reactions are sufficiently low as to not be a concern over the timeframe of several decades. These results mirror field results reported by Carey, et al (2006) on SACROC cores that had been exposed to a CO_2 flood for over 30 years. The results are also consistent with those reported by several authors investigating the integrity of wellbores and the sequestration of CO_2.

This work indicates a properly designed and placed Portland cement system can readily provide the requisite wellbore seal for the lifetime of the project. This is of course provided the cement slurry is properly designed and placed in the wellbore.

Cement – SACROC Experience

For CO_2 storage, a central concern has been wellbore integrity measured not in terms of decades but in terms of millennia. Active research programs such as those summarized in the recent wellbore integrity workshops highlight the body of scientific work currently being undertaken by academic, government and industrial institutions to address the issue.

Recently, cement core samples have been recovered from well 49-6 of the SACROC Field after 30 years of CO_2 injection. The specifics are as follows:

Table 7 - SACROC Cement Samples (Carey et al, 2006)

Parameter	**Value**
Drilled and Completed	1950
Service	10 years as producer 7 years as injector
Start of CO_2 Exposure	1972
Years of CO_2 Exposure	30
Cement above Formation	Portland (Neat)
Sample #1 Depth	6,550 feet
Sample #2 Depth	5,160 feet
Reservoir Temperature	120^0 F
Reservoir Pressure	2,610 psig

The following observations were made regarding the samples:

- *Both cement samples retained their ability to prevent significant CO_2 flow having air permeabilities in the tenth of a milliDarcy range.*

- *For sample #1, located 10-12 feet above the formation, some CO_2 migration had occurred along the casing-cement and casing-shale interfaces. No evidence of CO_2 migration was found through the matrix permeability of the cement itself. No similar evidence of migration was observed for sample #2, located 1400 feet above the formation.*

In light of foregoing results and current well completion practices, the following conclusions can be drawn:

- *In spite of not being formulated for acid resistivity, the 50 year old neat Portland cement has held up remarkably well under its service conditions and 30 years exposure to CO_2. Such performance bodes well for all CO_2 EOR wells.*

- *Nothing can be said definitively about the rate of CO_2 migration further up the wellbore other than, after 30 years of CO_2 exposure, it migrated at least 12 feet. However, the ~0.1 md measured permeability, structural integrity, etc. of the CO_2 altered (including the degraded layer) cement "indicates the cement retained its capacity to prevent significant transport of fluid (CO_2) through the cement matrix."*

- *The cement degradation deposits adjacent to the well bore were at most 0.125 inch thick, while those adjacent to the shale were 0.25 inch thick. It has been suggested that the cement degradation found at the cement- shale interface may have resulted from the presence of shale fragments (filter cake) which provided a fluid pathway.*

- *Specially formulated acid resistant cements, some containing latex additives, are used for CO_2 injection well completions today in severe CO_2 environments. More information on acid resistant and specialty cements is provided in Appendix 5.*

The best appraisal of the performance of well 49-6 can be found in the SACROC cement report itself, namely that: "The most basic observation of the SACROC core is that at well 49-6 Portland cement survived and retained its structural integrity after 30 years in a CO_2 environment. While the cement permeability determined by air permeability is greater than pristine Portland cement, it would still provide protection against significant movement of CO_2 through the cement matrix. The location of a sample at only 10-12 feet above the reservoir contact suggests that the majority of the cement forming the wellbore seal has survived and would provide a barrier to fluid migration." Since most of the CO_2 storage projects have a relatively short operational history (two decades or less), this is the most definitive data available on integrity of cements exposed to CO_2 over at least a 30 year time frame,

4.4.2 Cement Slurry Design

The lifetime storage of CO_2 will require permanent seal integrity, and making modifications to the standard Portland systems may further improve the reliability of the long-term seal and further reduce any perceived risks of using a standard Portland cement system.

Modifying Portland Based Cement Systems

A Portland cement system can be readily modified in many ways to further slow or prevent reactions with CO_2. Modifications include reducing the permeability of the cement matrix, reducing the amount of reactive species through use of specialty non-reactive materials, or protecting the reactive species through some sort of coating. All these methods have been applied in field operations.

Reducing the permeability of the cement matrix is one of the most cost-effective means of reducing the reactivity of the cement with CO_2, and one of the easiest to obtain. While there are several methods known to reduce the permeability of set cement, the most common is to simply change the water to cement ratio, increasing the proportion of cement. The increase in slurry viscosity is controlled using dispersants. Reducing the amount of water in the system will increase the slurry density, and can be a disadvantage in wellbores which cannot withstand the higher hydrostatic pressures brought on by the increased cement slurry density.

Many successful projects have also used diluents to reduce the density of the cement slurry and still achieve acceptable properties. One of the more common methods is through the use of pozzolans and flyash. These are cementitious materials that have been successfully used for decades and have a long history of application. Flyash additions allow slurry density reduction, reduce the amount of reactive material available, and serve to reduce permeability over systems extended with other materials like bentonite or silicates.

Substituting flyash by adding specialty materials that fill the pore spaces in the cement can also act to reduce system permeability and reduce the concentration of reactive species in the final system. A considerable body of work outlines the use of specific particle sized materials added to cement. The "tri modal" or three particle approach has led to the development of a number of high performance cement systems. These systems can cover an entire range of slurry densities, making them applicable to a wide range of wellbore conditions.

The addition of the specifically sized particles will not only reduce the permeability of the set cement, but also dilute the concentration of reactive species. As with the use of pozzolans and flyash, this technique offers some potential benefits beyond simple permeability reduction. The use of the specialty materials also can provide improved mechanical performance and higher strengths than those achieved with flyash systems.

An additional method for modifying Portland cement base systems is to protect the reactive species through addition of other additives. Advances are reported by Barlet-Gouedard et al. (2007) in their development of a Portland based system that appears to be resistant to CO_2.

These developments are significant in they utilize standard Portland cement. These cements are readily available and have a long history of providing an effective seal in a variety of environments. Their effectiveness has been demonstrated in field work, specifically the SACROC studies previously noted.

Laboratory testing of Portland based systems, however, has not consistently shown all Portland based systems to be acceptable in CO_2 environments. It is not clear if this is due to an artefact in laboratory testing as many of the testing apparatuses use similar exposure techniques.

As noted, the density of the slurry is often higher than cements mixed at "normal" density. In cases where the well cannot withstand the hydrostatic pressure of the higher density slurry, reducing the density may be the only method to properly place the slurry. In those cases, care should be exercised in the selection of extender, with preference being given to materials that can reduce slurry density while maintaining low permeability. This essentially limits the use of silicate type extenders or bentonite as the only extender in the system.

Most applications use an extended lead cement followed by a higher density tail system. This allows the majority of the well to be filled with a lighter cement system that reduces wellbore hydraulics, and then places a higher performance cement system across the areas of CO_2 injection. Again this higher performance system can be a reduced water Portland cement or one containing specialty materials and other additives.

Non-Portland Cements

Another approach to address long term seal quality in CO_2 injection wells is to replace Portland cement with a non-Portland system. Limestone, the principal material in Portland cement clinker, forms the basis for binder in Portland cement. The raw materials used to make non-Portland cements are less available than limestone, thus becoming more difficult to obtain. Examples of non-Portland cements include calcium sulfoaluminate-based cements, geopolymeric cements (alkali aluminosilicates), magnesium oxide cements, and hydrocarbon-based systems.

While less abundant, these systems are commercially available, and selected systems have been applied in wells for decades. One of the most resistant systems is a calcium aluminate cement that does not react with CO_2. This specialty cement has been used in many applications in oil and gas wells, and specifically in one of the highest-rate acid gas injection wells in the US.

Use of specialty cements is not a trivial decision and requires additional steps in the planning and execution phases. These materials are generally not compatible with Portland cement, and field operations must be planned to eliminate the potential for cross contamination. Since conventional cementing additives do not react in the same manner, additional laboratory testing is required. The effective density range for these slurries is narrower than with Portland cement blends, potentially limiting their application in some fields.

Work by Argonne National Labs has also identified ceramic based cements that show promise in wellbore applications. Originally part of an effort to identify materials to safely bind and encapsulate nuclear waste, the resulting systems may find application in lower temperature wells. The system is difficult to place at higher temperatures, but considering most CO_2 injection wells are planned for shallow, low pressure oil reservoirs, its potential use may have application on specialty projects.

4.4.3 Recommendations

Based on the available information, the design of the cement slurry may use Portland cement as its base, provided efforts are taken to reduce the permeability of the set cement, reduce the concentration of available reactive species and/or protect those reactive species through use of carefully selected additives. Lower density systems should use extenders that will allow permeability reduction which include flyash systems, additives such as found in the tri-modal systems and specialty additives that protect the reactive species in Portland cement. The use of silicate extenders or only bentonite is not recommended.

Non-Portland based systems that are resistant to CO_2 are commercially available though do require additional planning to assure proper design and prevention of contamination during the operations. These systems are not as readily available as conventional Portland systems, and thus may not be available in all areas. As noted the decision to use these systems is not trivial and requires considerable planning for logistics and operations.

5.0 KEY RISKS FOR CO_2 INJECTION WELLS VERSUS OIL AND GAS WELLS AND INJECTION REGULARITY

Key risk areas to be considered to assure life-cycle well integrity of CO_2 injection wells can be grouped under: (1) high pressure, (2) carbon dioxide corrosion, (3) well design, (4) well construction (drilling and workover), (5) material specifications and selection (casing/tubulars, cementing design, practices and cement job execution), and (6) plugging. Each of these key risk areas have been discussed in greater detail in the previous sections of this Report and a brief summary of the key risks and uncertainties for well integrity for both CO_2 EOR and CO_2 storage wells are presented in Table 8 below. In addition regularity/injectivity issues for both CO_2 EOR and CO_2 storage wells are presented at the end of this chapter.

Table 8 – Comparative Summary of Conventional Oil and Gas Injection Wells and CO_2 EOR and CO_2 Storage injection Wells

	Conventional Oil and Gas Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
High Injection/ Operating/ Reservoir Pressure Management	• Generally, not high for water injectors and oil/gas producers. • Important consideration in High Pressure High Temperature (HPHT), deep water and over- pressured reservoirs.	• A principal source of danger in a CO_2 facility is the high pressure (generally above 1,100 psi – 7.58 MPa) at which CO_2 is transported and injected (applicable for both CO_2 EOR and CO_2 storage facilities). • High pressure is particularly dangerous with CO_2 because of CO_2's high coefficient of thermal expansion – a small change in temperature can cause a large change in pressure. • Injection pressures are generally higher [~ (800 – 1,500 psi/5.52 – 10.34 MPa)] in CO_2 EOR wells than O&G production/injection wells. • Increased well pressures make workovers more difficult (See Appendix A7.4.11 and applicable to both CO_2 EOR and CO_2 storage injection wells).	• High injection pressures combined with low injection fluid temperatures can induce hydraulic fracturing. • Regulations may require maximum injection pressure not to exceed 90% of the injection zone fracture pressure (US) or 90% of the fracture pressure of the caprock (Norway). • Geomechanical models are required to determine the maximum injection pressure that will not induce fractures and to determine the in-situ stresses and faults, and fault re-activation hazard. Injection wells should be located as far as possible from faults.
CO_2 Corrosion	• CO_2 corrosion is generally not a factor in conventional O&G production/injection wells. Significant factor in acid/sour gas injection streams with CO_2 and H_2S present. • In a study of the K-12B gas field in the Dutch sector of the North Sea where CO_2 is injected, 5% of tubulars were degraded due to pitting corrosion (Mulders, 2006).	• CO_2 reactivity in water may corrode injection well materials (well tubular and cement) and can also change the reservoir properties in near wellbore region. • In WAG operations wetted surfaces often use specialty metallurgy (316 SS) and coatings to guard against corrosion (Contek/API, 2008). • Long-term stability of wellbore materials in CO_2-rich environment is a complex function of material properties and reservoir properties which need to be incorporated into well design and completion programs.	• In CO_2 storage projects, if dry CO_2 (with CO_2 purity above 95%) is injected in the supercritical state the corrosion risk is low and therefore, corrosion problems are not expected to be any more severe as compared to CO_2-EOR operations (Nygaard, 2010). • The corrosion rate will increase if the injected stream comes into contact with water. Possible water sources may include: connate water in the injection zone, free water in the cement or free water resulting from capillary condensation (Kolenberg et al., 2012). • See Sections 4.1 and 4.2

	Conventional Oil and Gas Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
Well Design & Construction (Drilling/ Workovers)	• All wells have two basic elements: the wellbore, (which includes the packer) and the tubing and wellhead valves assembly. • Multiple casing strings are used for a variety of reasons, including the protection of groundwater resources and maintaining wellbore integrity. • Drilling in environments such as HPHT, deep/ultra-deep water, steam assisted gravity drainage (SAGD), extended reach drilling (ERD and ultra-ERD), arctic, shale oil and gas, hydraulic fracturing, salt zone drilling and CO_2 injection results in complex loading conditions on the casing/ tubular/cement etc. (most commonly used casing design software is WELLCAT™) See Section 2.1.2. •	• Design and well construction of a CO_2-EOR injection well is similar to a typical oil and gas-related water injection well with most downhole equipment being virtually the same, except the wellhead. See Section 2.1.3 and Figure 4. • CO_2 EOR wells are either drilled as new wells or, as is quite common in existing fields, re-completed by converting producer or injector to a CO_2 EOR injector. • There are several major differences in wellbore remedial work between a water flood and a CO_2 flood (See Section 2.1.6). • Most operators with large CO_2 EOR operations (See Case Study # 4), maintain a workover rig on location for routine workover and maintenance. Ability to deploy a rig at short notice is also valuable in case a well control incident were to occur.	• A CO_2 storage well is in most cases similar to CO_2 EOR injection well, however, in some instances the design requirements for a CO_2 storage well may be more stringent, depending upon a case-by-case basis (See Section 2.1.4 and figures 5 and 6). • CO_2 will be stored for a long time period (decades). This imposes a number of requirements on the well design and specific procedures for its monitoring and abandonment as part of wider MMV (monitoring measurement and verification) requirements for the entire storage site depending on jurisdiction.
Well Integrity	• Conventional oil and gas wells have generally lower well integrity failure incidents than wells drilled in deep water, ERD, shale oil/gas and HPHT environments.	• Well integrity in CO_2 EOR wells needs to take account of exposure to corrosive CO_2, life of field and permanent entrapment of CO_2 within the reservoir. This is readily addressed by strict adherence to material selection requirements.	• Injection rates may be higher in CO_2 storage wells as compared to CO_2 EOR wells and can have impact on wells and near wellbore structures. • Some experimental observations like the abnormal pressure drop response obtained under a high injection rate suggest that

	Conventional Oil and Gas Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
(Well Integrity Cont.)	• Wells drilled in Gulf of Mexico indicate significant problems with SCP (sustained casing pressure), believed to be caused by gas flow through cement matrix (Crow, 2006). • In the Norwegian sector of the North Sea, ~13-15% of production wells experienced leakage, while 37-41% of the injectors experienced leakage (Randhol and Carlsen, 2008; and NPA, 2008). • Of ~ 316,000 deep wells analyzed in Alberta, 4.6% had leaks with gas migration occurring in 0.6% of the wells and surface casing vent flow (SCVF) in 3.9% of the wells (Watson and Bachu, 2007). • Main observation from these studies is that cased wells are more prone to leakage than drilled and abandoned wells, and injection wells are more prone to leakage than production wells (Nygaard, 2010).	• Typical problems encountered in CO_2 operations are discussed in Section 2.1.6 and Table 1. • Largescale CO_2 EOR operations like SACROC and Wasson Field (See Case Study # 4, Sections 2.1.6 and 5.1) suggest no major issues with life cycle well integrity management. • Problems from CO_2 corrosion and impacts on cement degradation have been handled with appropriate selection of materials of construction (well tubulars and cements) in CO_2 EOR operations (See Sections 4.3, 4.3.3 and 4.4) • Appropriate casing/tubing design to handle complex loads/stresses from CO_2 injection and CO_2 EOR operations have been successfully handled with appropriate casing/tubular design software (e.g. WELLCAT™ in Section 2.1.2). • Proper maintenance of CO_2 injection wells (both CO_2 EOR and CO_2 storage) is necessary to avoid loss of well integrity. Procedures to reduce loss of well control (LWC) incidents including blowouts and to mitigate the adverse effects if one should occur include: periodic well integrity surveys, improved BOP equipment maintenance, improved crew awareness, contingency planning and emergency response training (See Section 2.1.7).	solid particle displacement can occur leading to severe permeability impairment (Cailly et al, 2005). Evidence from Sleipner field does not support this observation. Laboratory work should be performed on the injection formation to assure no adverse impacts from high rate injection. • After CO_2 injection, the CO_2 plume may move upwards or sideways due to pressure difference and buoyancy, with wells providing an obvious pathway for CO_2 to escape from the injection zone (See Section 5.1 for leakage pathways and well integrity issues for CO_2 storage wells). • Intermittent supply of CO_2 (supply disruptions during unloading from a ship or during well interventions/repairs) can affect well integrity and injectivity. On-off injection leads to cyclical heating and cooling and can cause radial and hoop stresses in cement and lead to debonding (between cement and casing and/or rock) or disc or regular fractures. This can also have an impact on nucleation conditions (e.g.salt) and borehole deformation. The research-based advice is to avoid extensive pressure testing of annular barriers, ensure robust well construction, and minimize thermal cycling. The average time for well integrity problems to occur is ~ 2 years if wells are operated outside their initial design envelope and there is a strong dependence on quality of cementation (Torsaeter, M. –IEAGHG Modelling and Risk Management Combined Network Meeting, 2018).

	Conventional Oil and Gas Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
Material Selection & Specifications	• For wells 10,000 feet (3,048 m) or less in depth, carbon steel casing is typically used with J-55 and K-55 grades being more common. • In deep water (drilling through salt), HPHT, shale oil/gas hydraulic fracturing, acid gas (CO_2 and H_2S), and CO_2 EOR and CO_2 storage, higher strength grades and/or corrosion resistant alloys (CRA) are used. (See Section 4.3). • Most conventional oil and gas wells use API Class G and H Cements for typical applications. Other types are also used for specific applications - thermal, HPHT, deep water, Arctic, shale oil/gas, geothermal etc. (See Appendix 5 and Tables A5-1 and A5-2). • Cementing is critical to the mechanical performance and integrity of a wellbore both in terms of its method of placement and cement formulation used.	• CO_2 may be corrosive or non-corrosive depending upon the materials employed, temperature at the contact surface, water vapour concentration, CO_2 partial pressure and velocity effects (See Section 4.0). • Material selection guidelines for CO_2 EOR wells are given in Section 4.3.3 and Table 6. • Reaction of CO_2 with wellbore cement is slow in a well in which good construction practices and appropriate materials were used; in these cases CO_2 should not be a problem (See Section 4.4 and Table 7). • SACROC core evidence indicates Portland cement system can provide the requisite wellbore seal for the lifetime of the project. Making modifications to the standard Portland system may further improve the long-term reliability of the seal. • Non-Portland specialty cements that are resistant to CO_2 are commercially available. Use of these systems requires planning and logistics (See Sections 4.4 and 4.4.3 and Appendix 5 and Tables A5-1 and A5-2).	• Material selection for CO_2 injection wells depends on high strength requirements combined with high corrosion resistance of the material. • A chemical analysis of the reservoir fluids is required for evaluation of the corrosive components such as temperature and pressure profiles and stresses on the tubulars should also be considered. • Material selection has to consider that wells will be in contact with wet CO_2 especially in the deeper section of the well. • Other factors to consider should include material capabilities for low temperatures (brittle materials may not be adequate protection for a CO_2 leak) and oxygen-related corrosion impacts (See Sections 4.3 and 4.3.2 for corrosion resistant alloys (CRAs - Tables 4 and 5). • Material selection guidelines for CO_2 storage wells are given in Sections 4.3 and 4.3.4. • CO_2 resistant cement properties have been tested and evaluated at CO_2 EOR sites (see opposite) and Section 4.4.

	Conventional Oil and Gas Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
Injectivity and Regularity (ability to actually inject CO_2 at the desired rates necessary to store the delivered quantity)	• There are well established industry practices to address injectivity and permeability impairment or stimulation for conventional water injectors in oil and gas production. • Evidence shows loss of integrity much higher in injection wells compare to production wells – possible causes thermal cycling of fluids. • Changing use of well originally designed for a different purpose may compromise its re-use for a different function.	• Potential loss of injectivity and corresponding loss of reservoir pressure can have a major impact on the economics of a CO_2-EOR project (Rogers et al, 2001). Both injectivity increases and reduction have been observed in CO_2 floods including in several West Texas floods and the North Sea (after hydrocarbon injection). • Factors that affect injectivity include: low mobility in the tertiary oil bank; wettability; trapping and bypassing of gas; increased scaling; paraffin problems; asphaltene precipitation. Asphaltenes can plug up plungers, clog wellheads, tubulars, chokes, and surface/ production lines (See Section 5.2). •For EOR operations such as at Weyburn and Oxy's Denver Unit (See Case Study #4), the number and location of injection wells is part of the optimization program for oil recovery. Commercial CO_2 EOR operations need to take account of oil recovery and CO_2 recycling.	•CO_2 injection can alter mechanical properties of the reservoir rock by inducing chemical reactions. Precipitation of salts, mainly consisting of halite (NaCl), due to water vaporization can result in injectivity impairment around injection wells (Bacci et al, 2011, Hansen et al, 2013 and Sminchak et al. 2014). Some studies suggest that a high CO_2 injection rate should permit the injection process to continue with limited impact on injectivity even if significant halite precipitation takes place (See Section 5.3). •Fines migration can be remediated in theory by ensuring that injection proceeds at specific velocities large enough so that particle deposition occurs far enough from the wellbore. Borehole deformation in weaker/unconsolidated formations can be remediated by adding brine in the injector to re-stabilize the formation (Papamichos et al., 2010). •Geological heterogeneities resulting from faults intersection, reservoir compartmentalization or facies variation may be remediated by use of acid injection to open high permeable pathways from the injection well, or surfactants to alter the wettability of the lower permeability units and counteract the CO_2 trapping tendencies (Torsaeter et al., 2018). •Shale swelling can be addressed through concomitant injection of specific brine to restore salt balance (as is done when drilling through shaley intervals) such as inflatable packers or blank pipe connections. •Where the size of the aquifer is large and the

	Conventional Oil and Gas Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
			receiving formation has a high permeability (e.g. Utsira in Sleipner) CO_2 can be injected at a high rate without significant injectivity problems or a significant pressure increase. In less favourable locations, injectivity and injection regularity may become a crucial technical and economic challenge. Large scale storage of CO_2 requires reservoirs with sufficient capacity and good petrophysical properties to dissipate pressure build-up and avoid interference with adjacent oil and gas operations, if present.
Plugging **(P&A)**	• There are well established industry practices to properly plug and abandon conventional oil and gas wells. P&A of deep water offshore wells are more challenging and technological advances are being made to safely plug and abandon/decommission these wells and platforms. • Plugging and abandonment regulations for Texas are given in Texas Administrative Code (TAC) Title 16, Part I, Chapters 1 through 20 (See Section 7.1). Rule § 3.14 covers plugging requirements in Texas (RRC). • P&A regulations for Alberta	• Texas RRC Rule §3.14 covers plugging requirements for CO_2 EOR wells (See Section 7.1) and AER Directive 020 - Well Abandonment in Alberta, Canada (See Section 7.2). See Appendix 6 - Plugging and Abandonment of Wells for plugging procedure for CO_2 EOR wells. Please also see Table A6-1 - Description of Abandonment Methods.	• Many old, abandoned wells (completed and shut-in using practices and cement acceptable at the time) may not be suitable to use in long-term CO_2 storage systems. Leakage from abandoned wells has been identified as a potential "significant" risk in geologic storage of CO_2 (Oilfield Review, 2015). Evidence from the Cranfield, Mississippi site (See Section A2.8) does not support this view, where a specific investigation of legacy wells showed no detected evidence of CO_2 leakage. This does not mean legacy wells could leak but it is a matter of degree, risk assessment and remediation. Also, legacy wells were not designed for handling CO_2 (See Section 2.1.6). • Operational conditions affect well integrity which might be relevant if legacy wells are then used for CO_2 injection or even if new dedicated wells are used for CO_2 injection. Well design has to consider handling large

	Conventional Oil and Gas Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells
(P&A cont.)	are given in Alberta Energy Regulator (AER) Directive 020 -Well Abandonment in Alberta, Canada (See Section 7.2). • API Bulletin E3 "Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations", 1993 gives additional guidelines on P&A requirements (See Appendix 6).		volumes of CO_2 over several years with probably intermittent injection operations. • Storage in deep saline aquifers may also pose a lower risk (due to lower number of wellbores encountered) than those encountered in oil and gas fields. • Depleted oil and gas reservoirs are likely to incorporate a greater number of wells penetrating the reservoir caprock due to the historical exploitation of these fields. Seepage, migration, and leakage can occur from improperly plugged and abandoned existing old oil and gas wells. Since the operational history of CO_2 storage wells is relatively short as compared to CO_2 EOR wells, we do not have actual examples of plugged and abandoned CO_2 storage wells to compare key differences in plugging practices between these two types of wells. See Appendix 6 - A6.1 for Recommended Best Practice for Well Abandonment from a CCS Perspective and Appendix 3 (A3.6.5.2) for recommended practices for abandonment/ decommissioning of CO_2 wells. • A good understanding of well abandonment and remedial measures and current abandonment practices and regulatory requirements are necessary to assure safe and secure long-term storage of CO_2 in the subsurface reservoirs. A variety of techniques are employed around the world to facilitate well abandonment and state and federal regulatory agencies may specify the exact requirements for doing so.

	Conventional Oil and Gas Injection Wells	CO_2 EOR Injection Wells	CO_2 Storage Injection Wells

5.1 WELL INTEGRITY ISSUES FOR CO_2 STORAGE WELLS

When a CO_2 injection well is considered, the following issues need to be addressed (Cailly, 2005):

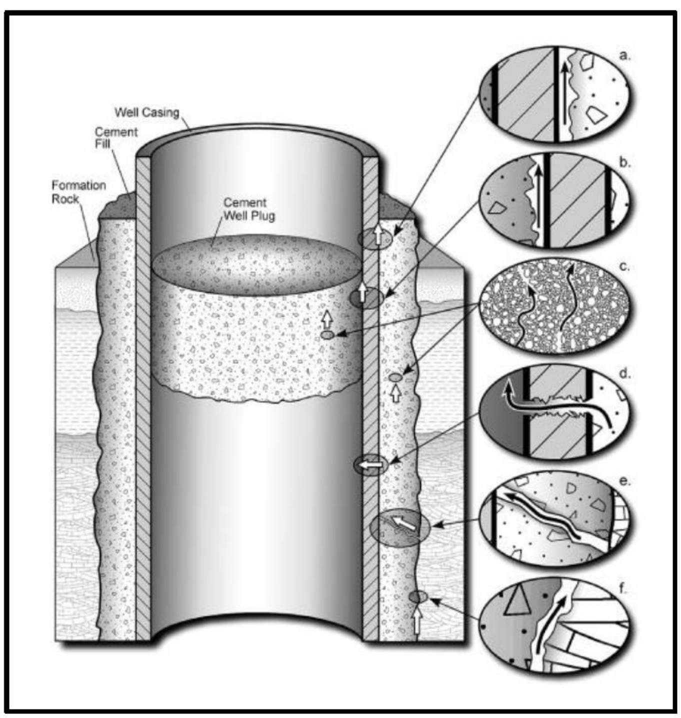
- *CO_2 is a reactive component, when dissolved in water it may cause some corrosion to the injection well materials (well tubulars and cement) and can also change the reservoir properties in the near wellbore region.*

- *Injection rates may be very high, which can also have a mechanical impact on wells and on near wellbore structures.*

- *CO_2 will be stored for a long time period. This imposes a number of requirements for the well design and specific procedures for its monitoring and abandonment.*

After CO_2 is injected into the subsurface, the CO_2 plume may move upwards or sideways due to pressure difference and buoyancy, with wells being an obvious pathway for CO_2 to escape from the reservoir formation. There are several possible pathways for the CO_2 leakage to occur as shown in Figure 12 (Celia et al, 2004) including: along the interfaces between the different materials, such as the steel casing cement interface (Fig 12a), cement plug steel casing (Fig 12b), or rock cement interface (Fig 12f); leakage through cement (Fig 12c) or fractures in the cement (Figs 12d and 12e). In addition, leakage can also occur when wells are only cemented over a short interval or the cement sheath is not uniformly covering the entire circumference of a well (particularly challenging in deviated/horizontal wells). Casing corrosion can also lead to casing failure with resulting leakage pathways and loss of well integrity.

Figure 12 - Example of possible leakage paths for CO_2 in a cased wellbore (Celia et al, 2004)



Several studies have investigated the integrity of the wells around the world. Of the 316,000 deep wells analyzed in Alberta, 4.6% had leaks with gas migration occurring in 0.6% of the wells and surface casing vent flow (SCVF) in 3.9% (Watson and Bachu, 2007). In a subset of 20,500 wells, 15% leaked with drilled and abandoned wells making up 0.5% and cased wells 14.5%. The reported leakage occurred mainly from formations shallower than those suitable for CO_2 injection and related to thermal operations such as steam injection for steam assisted gravity drainage (SAGD) or cyclic steam operations. In the Norwegian sector of the North Sea, between 13 and 19% of the production wells experienced leakage, while 37 to 41% of the injectors experienced leakage (Randhol and Carlsen, 2008; NPA, 2008). Further, estimates from the Gulf of Mexico indicate that a significant portion of wells have sustained casing pressure, believed to be caused by gas flow through cement matrix (Crow, 2006). In a study of the K-12B gas field in the Dutch sector of the North Sea where CO_2 is injected, 5% of tubulars were degraded because of pitting corrosion (Mulders, 2006). It should be noted that all the above investigations covered all types of deep wells and were not restricted to just CO_2 injection wells.

The main observation from these studies is that cased wells are more prone to leakage than drilled and abandoned wells, and injection wells are more prone to leakage than production wells (Nygaard, 2010).

Wellbore integrity issues can be divided into two types: improper completion and abandonment of the wells (this is particularly true for depleted oil and gas reservoirs which may have thousands of inactive or abandoned wells, with each well representing a potential pathway for the CO_2 to reach overlying aquifers or to the atmosphere); and the long-term stability of wellbore materials in a CO_2-rich environment. The long-term stability of wellbore materials in a CO_2-rich environment is a complex function of material properties and reservoir properties such as aquifer water(brine), rock/formation compositions, CO_2 and formation pressures, temperature gradients, and the rate of reaction of the materials with CO_2. Therefore, well design and completion of CO_2 injection wells differs from typical injection wells drilled in conventional oil and gas fields or natural gas storage projects.

In a study conducted of the 1000 wells in the Wabamun Lake, Alberta area (Nygaard et al, 2014), 95 wells penetrated the immediate caprock above the proposed Nisku injection formation and were identified as potential leakage pathways. Only four wells, for the subset of 27 wells studied, were identified as requiring a workover, a much lower number than was anticipated. Multistage simulations for casing/cement and cement/formation interactions with temperature enabled elements were conducted using a 3D-fiinite element model (built by use of poro-elastoplastic materials for cement and formation). The cement results indicated that thermal cooling might reduce near-wellbore stresses, thereby increasing the risk of integrity loss at the casing/cement and cement/formation interfaces. The parametric study revealed that the risk of de-bonding and tensile failure would increase with increasing Young's Modulus and Poisson's ratio of the cement under dynamic loading conditions. In addition, low mechanical cement strength would increase the risk of shear failure in the cement.

5.1.1 Other Wellbore Integrity Challenges for CO_2 Storage Wells

Two main types of reservoirs are considered for geological storage of CO_2: deep saline aquifers and depleted oil and gas reservoirs. The former offers a very large potential capacity and a more uniform distribution but with limited characterization of the geologic and engineering properties (including the caprock seal). The latter offers smaller overall capacity, but with a reduced risk due to a better knowledge of the geologic and engineering properties. However, in the latter case there is an increased risk from the large number of old active/inactive or plugged and abandoned wells that may provide a conduit for leakage of injected fluids.

Utilizing depleted oil and gas reservoirs can present challenges that have to be considered prior to initiation of long-term storage of CO_2. Some of the factors to be considered for the two storage options are (Loizzo et al, 2010, Cailly et al, 2005):

- *During injection, the pore pressure increase induces reservoir expansion. This phenomenon can result in shear stresses at the reservoir and cap-rock boundary. For anticline reservoirs, large horizontal compressive stresses can develop at the apex of the structure. In order to avoid this deformation, a preliminary geomechanical study is required to identify the maximum allowable pressure increase in the dome and related injection parameters.*

- *Depletion can cause pore collapse in the reservoir, with an associated loss of capacity and injectivity and can weaken cap-rock and bounding seals/faults and even well completions, resulting in potential loss of wellbore integrity.*

- *Oil and gas reservoirs are also intersected by many wells, and stricter regulatory requirements may require operators to re-confirm the quality of zonal isolation, by recompleting or working over wells that will be exposed to CO_2.*

- *Low reservoir pressure may also mean that injection of CO_2 in a dense phase may lead to reservoir fracturing and strong thermal effects resulting in injectivity and containment problems (Loizzo et al, 2010).*

- *Uncertainty on capacity and injectivity is clearly lower for depleted reservoirs, giving them a net potential economic advantage, whereas uncertainty on well containment favors saline formations, which are intersected by fewer wells.*

- *Injectivity in depleted reservoirs may be more difficult to ensure than in saline aquifers or in oil and gas reservoirs where pressure has been maintained (Loizzo et al, 2010).*

- *High injection pressures combined with low injection fluid temperatures can induce hydraulic fracturing which can affect the bounding seals (cap-rock and overburden). The Class VI Rule in the U.S. requires that the injection pressure not exceed 90% of the injection zone fracture pressure except during stimulation [40 CFR 146.88(a)]. This requirement also diminishes the likelihood of fracturing the confining zone/caprock. In some cases, stimulation including hydraulic fracturing may be required to achieve the desired injectivity of the CO_2 injection well and is usually performed during the initial completion or later when injectivity has declined over the course of the injection project. The operator must also demonstrate that the injection and/or stimulation will not fracture the confining zone or otherwise allow injection or formation fluids to endanger underground sources of drinking water - USDWs [(40 CFR 146.88(a)]. In other areas such as in the North Sea, regulatory agencies may require the maximum injection pressure not to exceed 90% of the fracture pressure of the caprock (e.g. in Snøhvit).*

- *Geomechanical models are required to determine the maximum injection pressure that will not induce fractures and to determine the in-situ stresses and faults, and fault reactivation hazard. The fault reactivation induced by in-situ stress changes is affected by factors such as the thickness, lateral extent and shape of the reservoir, the mechanical properties of the reservoir and the surrounding formations, and the presence, orientation and strength of existing faults within or around the reservoir. Injection wells should be located as far as possible from faults.*

- *Fault zones are widely recognized as being important to the secure long-term storage of CO_2 as they could provide a leakage pathway out of the target reservoir. CO_2 operations involve the injection and pressurization of reservoirs usually resulting in changes to the state of in-situ stresses which may modify fault properties. Instability could lead to slippage along pre-existing faults or fracture systems, which may be associated with seismicity. In addition, the movement of faults, and the generation of fractures within the damage zone adjacent to the core, may create conduits that allow escape of fluids to the overburden or to the surface. There is widespread experience of working with faults and fractures and provided there is sufficient characterization of their properties they should not restrict storage development. Mitigation measures to prevent potential leakage include: hydraulic barriers, biofilms and reactive cement grout and changing the subsurface pressure (Permeability 2016-13, IEAGHG 2016)*

- *Injection wells should intersect the highest permeability zones of the reservoir with the use of horizontal wells to be considered as an option for increased injection capacity.*

- *Depleted oil and gas reservoirs have a lower risk from potential fracturing of the formation, since re-pressurization can be done up to a pressure that is lower than or equal to the original reservoir pressure.*

5.2 INJECTIVITY ISSUES WITH CO_2 EOR INJECTION WELLS

CO_2 may undergo several reactions of interest in the oilfield. As discussed earlier, there are two basic CO_2 EOR techniques – continuous CO_2 injection and the WAG process. Initial industry concerns about CO_2 injection, especially during the WAG process in terms of controlling the higher-mobility gas: water blocking, corrosion, production concerns, oil recovery, and loss of injectivity have been addressed with careful planning and design along with good management practices, except for loss of injectivity. Injectivity is a key variable for determining the viability of a CO_2 project. Potential loss of injectivity and corresponding loss of reservoir pressure (and possibly loss of miscibility resulting in lower oil recovery) have potentially major impacts on the economics of a CO_2 EOR project (Rogers et al, 2001).

It is important to note that the dissolution potential of the system with two phases, i.e. a water phase and a CO_2 phase flowing simultaneously is very different from the situation where a water phase, saturated in CO_2, is the only mobile phase. In the former case, the dissolution potential is unlimited, whereas in the latter case, the acidity is removed progressively as the dissolution proceeds. On WAG projects, wetted surfaces in lines, valves often use specialty metallurgy (316 SS) and coatings to guard against corrosion (Contek/API, 2008).

Injectivity Increases/Injectivity Reduction

A number of CO_2 floods have seen higher gas injection relative to pre-water flood injection (e.g. North Ward Estes, Mabee and Cedar Creek Anticline) with some other projects with higher CO_2 injectivity after successive WAG floods (Rogers et al, 2001). However, Cailly et al 2005 reported that in a study done by IFP and Total, in the best case, the increase in injectivity was only 3 times the injectivity during water flooding.

Injectivity reduction after CO_2 injection has occurred frequently in West Texas, as well as in the Brent formations after hydrocarbon gas injection in the North Sea. The Levelland, Slaughter and Wasson fields producing from the San Andres formation have all reported injectivity loss during WAG process (Rogers et al, 2001).

Summary of Factors affecting Injectivity of CO_2 EOR Injection Wells (Rogers et al, 2001, Jarrell et al, 2002)

- *Low mobility in the tertiary oil bank significantly affects injectivity, especially for stimulated injection wells with non-stimulated production wells.*

- *Wettability is a complex critical parameter in injectivity reductions. Gravity forces dominate in water-wet conditions while viscous fingering is dominant in oil-wet conditions. Mixed wettability is suggested as a cause of low fluid mobility. Low injectivity in the carbonate reservoirs of West Texas is probably caused by the oil-wet or mixed-wet behavior of these rocks. In the Brent formation of the North Sea, larger pores tend to be oil-wet with residing oil, and small pores tend to be water-wet. Injected gas preferentially enters the high-permeability layers, resulting in a reduced water injection rate caused by the three-phase and compressibility effects.*

- *Trapping and bypassing of gas, like wettability, is a complex parameter in determining injectivity, possibly because of its link to wettability. Trapped gas creates significant hysterisis effects and reduced relative permeability to water, especially in mixed-wet and oil-wet reservoirs.*

- *Oil and gas saturations present in a miscible flood act to lower the maximum attainable water saturation, resulting in reduced water mobility.*

- *A lot of problems of injectivity losses are attributed to interaction between CO_2 and oil – miscibility problems, swelling, viscosity effects, precipitation of organic deposits – mainly asphaltene.*

- *Increased scaling problems in West Texas CO_2 floods have been reported by several authors. Lower bottom hole temperature and the presence of sulfate containing water increases gypsum scaling tendencies and decreases calcite scaling tendencies. The presence of gypsum may indicate a sulfur source presumably from H_2S. Gypsum scaling predominates in the wellbore, while calcite scale is more likely found in low-pressure surface equipment. While both polymer and phosphonate treatments are used to combat scale, phosphonate inhibitors are preferred by most operators (Jarrell et al, 2002)*

- *Paraffin problems have been reported in various fields. These deposits form when the temperature of the crude oil drops below its cloud point, which generally ranges between 60 and 65^0 F (15.5^0 to 18.3^0 C). Conditions favorable to paraffin deposition possibly are created when CO_2 expands as the reservoir fluids flow through into the wellbore and up the tubing and annulus. Methods used to handle paraffin deposition include: use of hot oiling or hot water combined with a paraffin solvent; pumping heavy aromatic solvents downhole; and mechanical cleanouts. Methods to prevent paraffin deposition include: increase back-pressure on the wells to keep both CO_2 and light-end hydrocarbons in solution; use of down-hole heaters; and use of crystal modifiers which raise the cloud point (can be effective but very costly). Because of varied crude compositions and operating conditions, an industry consensus has not formed on how best to handle the problem (Jarrell et al, 2002).*

- *Increased asphaltene precipitation has occurred in many CO_2 floods, usually not during primary or waterflood operation but after CO_2 breakthrough. Asphaltenes can plug up plungers, clog wellheads, and cause plugging in tubulars, chokes, surface and production lines. Major factors related to asphaltene deposition included: most severe during cold weather and concentration of CO_2 in the oil (Hansen, 1987 and Srivastava et al, 1995). Production declines from asphaltene problems generally were confined to production equipment and not as a result of deposition in the reservoir. To prevent asphaltene deposition, back-pressure has been successful in keeping light hydrocarbons in solution, which helps prevent asphaltene deposition.*

5.3 INJECTIVITY ISSUES WITH CO_2 STORAGE WELLS

- *CO_2 injection can alter mechanical properties of the reservoir rock by inducing chemical reactions (dissolution and precipitation of minerals), in particular CO_2 precipitation in calcite. Precipitation of salts, mainly consisting of halite (NaCl), due to water vaporization can result in injectivity impairment around injection wells (Bacci et al, 2011, Hansen et al, 2013 and Sminchak et al, 2014). Calcite precipitation can threaten the injection by cementing the reservoir around the rock. The related dissolution of the matrix provokes a risk of subsidence and fracture. Numerical models are used to simulate geomechanical effects triggered by chemical interactions between CO_2 and reservoir rocks.*

- *Carbonates are the first minerals to be dissolved and these dissolutions occur very fast, as soon as the injection starts. The precipitation of these minerals following these dissolutions is called CO_2 mineralogic trapping. It represents a mineralogic way of CO_2 storage that lasts for centuries, however this process can threaten the formation injectivity by cementing the matrix thus lowering the overall permeability (Brosse et al, 2002 in Cailly et al, 2005). This phenomenon may not be a significant concern, since in most clastic reservoirs it forms a minor portion of trapped CO_2 which either gets trapped by solution or within pore spaces.*

- *It is interesting to note that high rates tend to limit the permeability reduction due to precipitation due to a shorter residence time of the fluids. From a practical point of view, it suggests that severe permeability impairment in the near wellbore can be avoided in spite of unfavorable geochemical conditions if the injection rate is high enough to displace the equilibrium area of precipitation far from the well (Cailly et al, 2005).*

- *Permeability impairment due to CO_2 that dissolves water with subsequent salting out of NaCl has been reported around several gas producing wells, especially in high pressure high temperature (HPHT) wells which are characterized by very high salinity brines with a similar problem reported for the injection of dry natural gas in saline aquifers during gas storage operations. Precipitation of salts, mainly consisting of halite (NaCl), due to water vaporization can be a serious source of injectivity impairment around injection wells where dry CO_2 is injected in saline aquifers. This can lead to reductions in porosity and permeability of the reservoir in the vicinity of the wellbore, which can significantly affect injectivity (Bacci et al, 2011).*

- *With regard to CO_2 storage, numerical modeling has recently highlighted the potential for significant well injectivity losses due to halite precipitation in saline formations (Bacci et al, 2011). Depending mainly on the initial liquid saturation, salt precipitation around injection wellbores has different impacts: when the brine has a low mobility, the evaporation front moves with limited halite scaling and affects well injectivity only slightly. On the other hand, when the brine has sufficient mobility, the precipitation front is continuously recharged by the brine flowing to the well due to the capillary pressure gradient driven by the evaporation, and can significantly decrease the formation permeability (Bacci et al, 2011). Some of these studies suggest that a high CO_2 injection rate should permit the injection process to continue with limited impact on injectivity even if significant halite precipitation takes place (Carpita et al, 2006). Core flood experiments conducted using a St. Bees core sample saturated with NaCl brine showed that a small reduction in porosity can lead to significant permeability reduction, with a porosity decrease from 22.59% to 16.02% resulting in a permeability reduction from 7.78 mD to 1.07 mD. Petrophysical data was used to calibrate a Verma-Pruess "tube-in-series" model for use in numerical simulations and the calibrated model can be used to obtain more accurate results from numerical simulations.*

- *Reactive transport phenomena during CO_2 injection have been studied both for sandstones and carbonates. The experimental results showed that the permeability can either be enhanced or impaired and that injectivity is case dependent because it is related to the rock fabric, the fluid compositions, the thermodynamic conditions, and the flow regime. The coupling between transport and reaction is prone to generate specific porosity/permeability relationships according to the flow regime. These relations are very important to introduce in the numerical model to properly reproduce the pressure field around the well and the stress variations that can be detrimental for wellbore integrity (Cailly, 2005).*

- *Some experimental observations like the abnormal pressure drop response obtained under a high injection rate suggest that solid particle displacement can occur leading to severe permeability impairment.*

- *The simultaneous flow of CO_2 and brine is also important to consider since it limits the access of the reactive brine to a limited portion of the pore space due to the non-wettability of the CO_2 phase.*

- *Several coupled physical and chemical processes may occur during the injection depending on time and location within the reservoir. Far field regions are facing long-term reaction in a situation where flow of gas and water at a reduced rate may induce near fluid-rock equilibrium. In contrast, near* *wellbore regions are subjected mainly to gas at a high flow rate where dissolution/precipitation phenomena may drastically increase/decrease injectivity.*

- *CO_2 is not an inert gas like natural gas leading to its interaction with rock minerals of the rock matrix.*

- *Lower injectivity is not necessarily a near-wellbore effect*

- *Additional major factors that influence CO_2 well injectivity (Torsaeter et al, 2018) include: fines migration, geomechanical factors (like borehole deformation), chemical/thermal factors, geological factors and, rock heterogeneity.*

  - *<u>Fines migration</u> An injectivity issue commonly observed in waterflooding but not often considered in CO_2 storage is physical pore obstruction by fines migration and rock compaction. Fines migration can be remediated in theory by ensuring that injection proceeds at specific velocities large enough so that particle deposition occurs far enough from the wellbore.*

  - *<u>Borehole deformation</u> field data indicates that water injection into soft sands typically causes sand production, wellbore fill and near well-bore plugging accompanied by severe injectivity loss over time (Khodaverdian et al, 2010). In the case of CCS, this is a concern directly transferable to injection into depleted oil and gas reservoirs, unless water injection has already occurred and injectivity problems have been solved. Injection into soft sands is highly relevant for CO_2 storage projects on the Norwegian Continental Shelf and the Troll field (which is adjacent to and in the same reservoir formations as the planned CO_2 injection site at Smeaheia) is very unconsolidated and weak (Torsaeter et al, 2018). One option to remediate borehole deformation in weaker/unconsolidated formations is to add brine in the injector to re-stabilize the formation (Papamichos et al, 2010).*

  - *<u>Shale swelling</u> When the clay minerals interact with water, their volume increases (they swell). The same happens when CO_2 is present, at least in brine solution or in contact with resident brine (Busch et al, 2010). Concern with CO_2 is whether clay minerals present in the reservoir can swell to the point of reducing injectivty. Shale swelling can be addressed by concomitant injection of specific brine to restore salt balance (as is done when drilling through shaley intervals) or use of inflatable packers or blank pipe connections.*

  - *<u>Geological heterogeneities</u> can be divided into two categories: (a) the presence of alternating layers of contrasting mechanical properties, pore pressure and/or lithology (e.g. Sleipner and the Illinois Basin Decatur Project (IBDP)); and (b) the presence of faults and compartmentalization of the intended storage reservoir (e.g. Snøhvit where the sealing and compartmentalization was confirmed with continuous pressure increase with injection time). Geological heterogeneities resulting from faults intersection, reservoir compartmentalization or facies variation may be remediated by use of acid injection to open high permeable pathways from the injection well, or surfactants to alter the wettability of the lower permeability units and counteract the CO_2 trapping tendencies (Torsaeter et al, 2018).*

To predict the real injectivity of a well more research needs to be done. There are still many knowledge gaps related to CO_2 injectivity issues. Dedicated laboratory experiments in realistic field conditions should be performed, to better understand the different impairment mechanisms, while also testing remediation strategies. Improved simulation tools for predicting and handling CO_2 injectivity issues – salt precipitation, thermal, chemical, geological and geomechanical impacts including geological heterogeneities, fines migration, clay swelling, borehole deformation etc. Coupling of some of the injectivity loss mechanisms may also be required in the simulation tools (Torsaeter et al, 2018).

For a typical coal-fired power plant up to several million tons of CO_2 will have to be injected for storage over a period of 30-40 years. Operations in Sleipner and Weyburn are in this order of magnitude. For EOR operations using CO_2 injection like Weyburn, the number and location of injection wells is part of the optimization program for oil recovery. In the case of CO_2 storage in a deep saline aquifer, a major economic objective is to minimize the number of injection wells. Due to the size of the Utsira aquifer at Sleipner and the high permeability of the receiving formation, CO_2 can be injected at a high rate without significant injectivity problems or a significant pressure increase. In less favorable locations, injectivity and injection regularity may become a crucial technical and economic challenge. Commercial CO_2 EOR operations need to take account of oil recovery and CO_2 recycling. Large scale storage of CO_2 requires reservoirs with sufficient capacity and good petrophysical properties to dissipate pressure buildup and avoid interference with adjacent oil and gas operations if present.

5.4 RESERVOIR MODELLING FOR CO_2 INJECTION (IEAGHG, 2010)

Injection of fluids into the subsurface has a long and well established history in the petroleum and groundwater industries. In the last couple of decades, analytical solutions and numerical modeling codes have been amended to model the subsurface migration of injected CO_2.

Despite the progress that has been made in deriving analytical solutions that also account for gravity effects, a full two-phase solution involving gravity and relative permeability, has not been obtained. Therefore, numerical simulation remains the usual approach in estimating injectivity for CO_2 storage sites (IEAGHG, 2010). See also Sections 8.4, 8.5 and Appendix A2.8 for modelling studies done at Oxy's Denver Unit, Wasson Field; Uthmaniyah, Saudi Arabia; and at the Cranfield, Mississippi CO_2 storage site.

5.4.1 Simulation Software

Simulation software used for modelling CO_2 injection can be divided into two categories: (1) commercial software developed in the petroleum industry and adapted for CO_2 (most common are ECLIPSE – Schlumberger and GEM – Computer Modeling Group), and (2) in-house or developed by research institutions (example is TOUGH2 – Lawrence Berkeley National Laboratory). A listing of codes that have been used in simulations of CO_2 injection, with a reference to typical applications, have been presented in Table 2 of IEAGHG's 2010 Report "Injection Strategies for CO_2 Storage Sites".

Streamline Simulation

Streamline-based simulation techniques have been developed in the oil industry as an alternative to the traditional grid-based finite-difference methods (Thiele et al, 2010). The principal advantages of streamline simulation are computational speed and memory efficiency, allowing the simulation of much finer grids, and the immediate visualization of flow paths. The difficulties with streamline simulation occur when there is physics that is transverse to the main direction of flow, such as diffusion, compressibility or buoyancy (IEAGHG, 2010). Qi et al (2009) have extended an existing streamline simulator to four-component transport (water, oil, CO_2, and salt) and applied it to design CO_2 injection strategies in a highly-heterogeneous million-grid block model of a North Sea reservoir where CO_2 and brine are injected together (IEAGHG, 2010).

Percolation Theory

Conventional reservoir simulation is based on Darcy's law for flow of a viscous fluid. However, when viscous forces are negligible, very slow two-phases are dominated by capillary and gravity forces. There is evidence that these slow flows are best modelled by pore-scale network models, with the simplest of these models being based on percolation theory (Larson et al, 1981). Percolation models have two main variants: ordinary percolation and invasion percolation.

An important application of invasion percolation with buoyancy has been to the secondary migration of oil. Secondary migration is the slow process occurring over geological timescales where oil migrates from source rocks where it is formed into structural or stratigraphic traps. Permedia Research Group has developed a code (MPath), based on invasion percolation for secondary migration (Carruthers, 2003). This code has been applied to CO_2 migration at Sleipner (Cavanagh and Haszeldine, 2009) and In Salah (Cavanagh and Ringrose, 2009).

In a separate application, Zhang et al. (2009) have applied percolation theory to calculate the connectivity of stochastic fracture networks for estimating the probability of CO_2 leakage into shallow aquifers. This applies percolation theory to the solid rather than the fluids. If the fracture density is below the percolation threshold the fractures are disconnected and do not create a migration path (IEAGHG, 2010).

6.0 CO_2 BLOWOUTS – OVERVIEW OF RISKS FROM POTENTIAL LOSS OF WELL CONTROL

6.1 MAIN CAUSES OF LOSS OF WELL CONTROL IN CO_2 WELLS

When the drill bit penetrates a permeable formation that has a fluid pressure in excess of the hydrostatic pressure exerted by the drilling fluid, formation fluids will begin displacing the drilling fluid from the well. The flow of formation fluids into the well in the presence of drilling fluid is called a *kick.*

A kick is physically caused by the pressure in the wellbore being less than that of the formation fluids, thus causing sudden flow. This condition of lower wellbore pressure than the formation is caused in two ways. First, if the mud weight is too low, then the hydrostatic pressure exerted on the formation by the fluid column may be insufficient to hold the formation fluid in the formation. This can happen if the mud density is suddenly lightened or is not to specification to begin with, or if a drilled formation has a higher pressure than anticipated. This type of kick is called an underbalanced kick. The second way a kick can occur is if dynamic and transient fluid pressure effects, usually due to motion of the drill string or casing, effectively lower the pressure in the wellbore below that of the formation. This second kick type is called an induced kick.

A blowout may consist of water, oil, gas or a mixture of these. Blowouts may occur during all types of well activities and are not limited to drilling operations. In some circumstances, the well will bridge over, or seal itself with rock fragments from collapsing formations downhole. Uncontrolled flows cannot be contained using previously installed barriers and require specialized intervention services.

Blowouts in gas producers containing high concentrations of CO_2 have occurred in the past during drilling/production operations including well control problems on CO_2 source production wells in New Mexico, Colorado and Wyoming. There has also been an increasing frequency of well control problems in CO_2 injection wells, and whether this increased frequency represents a trend is unknown (Skinner, 2003).

CO_2 adds to well control risk since reservoir pressure is usually increased in a CO_2 EOR flood to improve oil-CO_2 miscibility and CO_2 is a buoyant and low viscosity fluid. Continued injection results in higher reservoir pressures in most projects with CO_2 now at or above its critical point. The extreme expansion of this fluid when surface pressure control is lost and the resulting intensity of the CO_2 blowout may be much larger than conventional oil and gas blowouts. CO_2 blowouts may have complications that other blowouts may not exhibit, due to the characteristics of CO_2. Within the regulatory community, loss of well control has also been referred to as surface/subsurface releases, mechanical failure, downhole problem, and illegal releases. Some of these names describe symptoms that can identify the occurrence of a blowout (e.g., leakage) rather than the actual event itself. For example, the CO_2 injected fluid can migrate laterally to an offset well (or an inactive/abandoned well) that has not been cemented opposite the injection interval or has not been plugged properly and then migrate to the surface or an overlying aquifer/formation.

Pressure vs phase changes

The tremendous expansion of supercritical CO_2 when pressure containment is lost is of great significance from a well control perspective. Figure 1 in Section 2.1.1 presented the CO_2 phase diagram showing its critical point at 7.37 MPa and 31.1^0 C (1,071 psi and 88.0^0 F). Above this pressure and temperature, there is no distinction between liquid and vapor phases, and even small pressure drops can produce large volume increases, and vice versa. Minimum miscibility pressure (MMP) for most CO_2/crude oil systems exceeds critical pressure; and reservoir temperatures are greater than the critical temperature for most, if not all, injection projects. Thus, most floods in which injection has been underway for several years contain CO_2 at conditions above the critical point.

When pressure containment is lost, two processes occur simultaneously. First, the CO_2 (and a fraction of miscible products) converts from a supercritical "fluid" to a vapor, with significant expansion. This vapor continues to expand with decreasing confining pressure as it moves up the wellbore. Flow velocities increase accordingly. Any mud or other fluid in the well is expelled quickly, leaving little hydrostatic pressure to resist reservoir fluid influx. The result is that more supercritical CO_2 flows into the wellbore, expanding as it does.

The flowrate eventually stabilizes, as equilibrium is established between backpressure caused by fluid friction from the blowout and the pressure drop across the formation face. Often, the flowrate is controlled by the opening through which the plume escapes at the surface. Flow through small openings (holes in casing, leaks around pipe rams or in the wellhead, etc.) can reach sonic velocity, limiting flow rate and consequently, CO_2 influx from reservoir to wellbore.

This flow behavior is almost explosive in its violence, and usually not expected by field/rig workers. Often, only a small volume of supercritical "liquid" CO_2 in the wellbore is enough to trigger the process, causing the well to blowout in a matter of seconds. Reaction time is minimal and some equipment, particularly manual BOPs and stab-in safety valves, cannot be installed and closed fast enough to avoid complete liquid expansion from the well and total loss of pressure control.

The second effect is rapid cooling of wellbore and fluid streams due to expansion. Once the CO_2 stream falls below the triple point temperature and pressure of – 56.6^0 C and 0.519 MPa (- 63^0 F and 76 psi), solid dry ice particles can form very quickly. Several special problems can result from this unique phase behavior: (1) high flow rates complicates surface intervention work and expose workers to gas moving at high velocities; (2) CO_2 and produced fluids form hydrates that can collect in BOPs, the wellhead and other surface equipment; (3) the cold CO_2 condenses water in the atmosphere, resulting in reduced visibility in the white "cloud" around the wellbore; and (4) free oil and condensed miscible fluids swept out of the near wellbore area can collect on the surface, creating a ground-fire hazard. Further, dry ice formation results in pea- to marble-size projectiles expelled at very high velocities (Skinner, 2003).

Corrosion effects on well control

Failures from CO_2-related corrosion can cause the loss of well control. Producing wells with even moderate CO_2 concentrations have suffered corrosion-related problems. This so-called "sweet corrosion" is well documented in the literature and results from formation of mild corrosives in CO_2-water reactions. While not as rapid as "sour" corrosion caused by H_2S or strong acid solutions it, over time, is just as insidious.

6.2 PREVENTION

Loss of well control occurs any time when fluids migrate slowly or rapidly through or along an engineered well system in a manner other than the designed operation into an unintended geologic formation or to the surface. Both human factors and unforeseen reservoir conditions can contribute to their occurrence, and safety procedures, in-depth personnel training and specialized equipment is used to minimize their likelihood.

The well control system prevents the uncontrolled flow of formation fluids from the wellbore or into lower pressured subsurface zones (underground blowout) – API RP 54, API STD 53. The well control system permits (1) detecting the kick, (2) closing the well at the surface, (3) circulating the well under pressure to remove the formation fluids and increase the mud density, (4) moving the drill string under pressure, and (5) diverting flow away from rig personnel and equipment. Several types of events/conditions are grouped under the category of "loss of well control" with well blowout being the most extreme event.

Kick detection during drilling operations usually is achieved by use of a pit-volume indicator or a mud flow indicator. Both devices can detect an increase in the flow of mud returning from the well over that which is being circulated by the pump.

The flow of fluid from the well caused by a kick is stopped by use of special pack-off devices called blowout preventers (BOPs). Multiple BOPs used in a series are referred to collectively as a BOP stack. The BOP must be capable of terminating flow from the well under all drilling conditions. When the drill-string is in the hole, movement of the pipe should be allowed to occur. In addition, the BOP stack should allow fluid circulation through the well annulus under pressure. These objectives usually are accomplished by using several ram preventers and one annular preventer. Both the ram and annular preventers are closed hydraulically. In addition, the ram preventers have a screw-type locking device that can be used to close the preventer if the hydraulic system fails.

Modern hydraulic systems used for closing BOPs are high-pressure fluid accumulators similar to those developed for aircraft fluid control systems. The accumulator is equipped with a pressure-regulating system and is capable of supplying sufficient high pressure fluid to close all of the units in the BOP stack at least once and still have a reserve. The accumulator is maintained by a small pump at all times, so the operator has the ability to close the well immediately, independent of normal rig power. For safety, stand-by accumulator pumps are maintained that use a secondary power source. The accumulator fluid is generally a non-corrosive hydraulic oil with low freezing point, good lubricating characteristics and must be compatible with synthetic rubber parts of the well-control system.

The control panel for operating the BOP stack is usually placed on the derrick floor for easy access by the driller. The arrangement of the BOP stack varies considerably and depends on the magnitude of the formation pressures in the area and the type of well control procedures used by the operator.

Examples of blowouts that have occurred onshore related to CO_2 injection wells are presented in this Report. For offshore incidents of Loss of Well Control (LWC) incidents, a good discussion is presented in API Standard 65 – Cementing Shallow Water Flow Zones in Deep Water Wells and API Standard 65-2 – Isolating Potential Flow Zones during Well Construction.

6.3 BLOWOUTS IN CO_2 EOR WELLS AND CO_2 PRODUCTION WELLS – CASE STUDIES

The following are brief case studies of CO_2 blowouts requiring well-control intervention services. Blowout Numbers 1 to 3 are reported to have occurred during the period 2000-2003 (Skinner, 2003):

Blowout No. 1: This well in a miscible, West Texas CO_2 displacement project, was an injector being serviced to replace corroded tubing joints and packer. The tapered 2.875 inch (73mm) x 2.375 inch (60mm) tubing was being pulled, and only a few joints of 2.375 inch (60 mm) tubing and the packer were left in the hole. Air slips were chained to the top of the dual manual BOP.

The well began to flow unexpectedly, and the crew closed the manual BOPs, dressed with 2.875 inch (73 mm) ram blocks. An early report indicated at least one tubing joint was ejected and hung in the derrick. The well blew out within 30 seconds and the crew evacuated.

The air slips had apparently opened at some point allowing the tubing to drop into the BOP. The tubing was hanging on the partially closed pipe rams and the air slips had cocked sideways, spreading the plume horizontally around the wellhead with poor visibility. The pipe rams were opened to drop the tubing and packer. An attempt was made to close the blind rams, but they were frozen in place. It was not possible to confirm whether the tubing had fallen downhole, due to ice buildup in the BOP. Fluid could not be pumped into the frozen wellhead. A hot-oil truck thawed the wellhead and BOP, and 242 barrels (38.5 m^3) of water were pumped.

The next morning the hot oiler again thawed pump lines, tubing head and BOP. The pump began injecting water down the annulus at about 0.5 bpd (0.08 m^3/d). Control specialists confirmed the tubing had dropped and the BOP stack was clear. Pump rate was increased to help load the well. Then blind rams were worked to break them free, and they were closed.

High-rate CO_2 flow from the well had apparently damaged the ram packers and the BOP leaked badly, indicating it could fail at any time. The pump rate was increased to 20 bpd and the well was killed. The BOP was stripped off and a new stack was nippled up. The dropped tubing and packer were fished, and workover operations proceeded without further problems.

Blowout No. 2: This well was an active CO_2 injector that was being converted to reservoir pressure monitoring. Plans were to squeeze the top of a 4½ inch (11.43 cm) liner and run new tubing with sensors and a packer. The well was killed, injection tubing was pulled and the old packer was removed.

A cement retainer was started in the hole on the old tubing. With the retainer at 6,300 feet (1,921 m), a pickup joint was made up on the injection tubing and run. Pipe rams were closed on the tubing, air slips were set and a stab-in safety valve was installed. Blind rams were left open.

The next morning crew found CO_2 blowing from the BOP. Swept-out-oil had collected on location in pools and puddles. It was unlikely that the gas plume would ignite due to its high CO_2 concentration, but oil on the ground was a serious fire hazard, so a foam blanket was applied. Then, the specialists approached the blowing well and confirmed that all flow was coming out the top of the BOP – it appeared that the pipe rams had failed. A line was laid and 177 barrels of brine were pumped down the annulus without affecting flow. The rig could not be started because of the fire hazard, so a winch truck was backed in to raise the blocks.

The tubing was raised, and a saddle was installed to hot tap the tubing with a 0.5 inch (12.7 mm) bit. About 300 barrels of brine was pumped down at 4 ½ bpm to kill the blowout, but the well continued flowing. Pipe rams were closed on the tubing; flow stopped; and the well finally killed by bull heading fluid down the annulus.

The pickup joint was backed off and laid down and was found to be flattened slightly on one side – an area only about ¾ inch (19 mm) wide and about 1/16th inch (1.6 mm) deep, the length of the joint. It appeared that the joint had been pulled through a partially closed blind ram and the entire CO_2 flow had exited the well between the flat spot and the closed pipe ram. When the rams were closed on the undamaged joint, the flow stopped.

Blowout No. 3: This well was also an injector in a miscible CO_2 flood that required a workover to clean out fill. The well was killed, the packer released and injection tubing pulled and stood back.

A small-diameter "stinger" made from 1½ inch (38 mm) tubing was screwed onto the bottom of a joint of tubing, as had been used to clean out other wells. The crew elected not to install an annular preventer or change pipe rams before running the stinger.

Blind rams were opened and the crew lowered the stinger. Suddenly, the well began to flow. Pipe rams were closed, but they would not seal around the small-diameter stinger. An attempt was made to lower the stinger and tubing joint, but flow uplift would not let the tubing down. The crew apparently attempted to drop the tubing but, instead of falling, the stinger bent and the joint fell over. Oil reached the surface a few seconds later and the crew evacuated. Oil collected on the location, and dirt beam was pushed around the site to contain it.

A single jet abrasive cutter was rigged up on a boom and a line was run up to a pump truck. Gelled fluid and an abrasive were mixed and pumped through the jet and the boom was telescoped to the correct position to cut the stinger off just above the BOP. The cut was made and the stinger fell into the hole, and blind rams were closed stopping the flow. The well was killed by bull-heading brine down the casing, and the stinger was fished after the annular preventer was rigged up.

Blowout No. 4: In March 1982 a CO_2 production well in the Sheep Mountain Unit, Colorado blew out. Following four unsuccessful attempts to kill the well with conventional weighted-mud techniques, the well was brought under control in early April 1982 by the dynamic injection of drag-reduced brine followed by mud. The dynamic kill technique uses frictional pressure losses to supplement the hydrostatic pressure of a light-weight kill fluid injected at high rate at or near the bottom of the well.

Two factors were the primary causes of the failure of the conventional kill technique. First, while injection of kill fluid down the drill pipe was possible, hydraulic constraints and pressure limitations significantly limited the rate of kill-fluid injection. Second, the kill operation was further complicated by the high flow capacity of CO_2 from the reservoir, later calculated to be at least 200×10^6 scf/day(5.6×10^6 m^3 /day), which efficiently gas-lifted the kill fluid up the annulus.

The Sheep Mountain Unit is located in Huerfano County, in south central Colorado. The unit is topographically dominated by Sheep Mountain [(elevation 10,635 feet (3,242 m)] and Little Sheep Mountain [(elevation 9,616 feet (2,931m)]. Slopes vary from nearly level, in bottoms and on terraces, to 40% in the foothills and to 60% on the talus slopes of the two mountains. As a result of this topography, all development wells are directionally drilled from centrally located drill site pads to develop the underlying Dakota and Entrada CO_2 reservoirs properly.

Well 4-15-H was the fourth development well to be drilled from Drill site 2. The well was planned to penetrate the Dakota sand in a highly productive area of the CO_2 reservoir. On February 27, 1982, a conventional rotary rig was skidded over the well. After the BOP equipment was pressure tested and the preset surface casing shoe was drilled at 277 feet (84 m), open hole operations began. The $9^{5/8}$ inch (245mm) directionally drilled hole proceeded as planned. Mud seepage and losses were encountered in intervals between 1,093 to 3,202 feet (333 to 976 m) measured depth. Mud weights were increased to a maximum of 10.3 lbm/gal (1,230 kg/m^3) from 8.4 lbm/gal (1,000 kg/m^3). Three cores were cut between 3,603 and 3,703 feet (1,098 to 1,129 m). The mud pits indicated that the proper amount of mud had been used for drill string displacement on the trip, and no flow was detected. A drilling assembly was tripped back in the hole and the hole circulated with no gain in pit level in preparing to ream the cored hole. A 42 barrel (6.7 m^3) gain in pit level was detected at 6:30 pm, March 17, 1982, with gas to surface after circulating for 20 minutes. The annular preventer was closed on the Kelly with 350 psi (2.41 MPa) shut-in annular pressure. Kill-weight mud mixing operations were initiated, the crew moved off the rig, and mud-mixing operations were also initiated at rigs at the other two drill sites and at the central mud plant.

Approximately 3 hours later, gas started flowing from the bradenhead valve on Well 2-10-0, an offset well approximately 200 feet (60 m) away, as well as from surrounding surface fissures. This showed that there was a communication between Well 4-15-H, offset wells, and surface fissures.

Between March 17 and 23, 1982, four attempts were made to kill the well by use of conventional weighted-mud techniques. On March 24, 1982, three large diameter (approximately 2-3 feet [0.6 – 0.9 m] fissures opened 750 feet (229 m) northeast of the well on the slope of Little Sheep Mountain. At this time, the choke lines and casing valves had frozen solid. The flow from around the surface casings and offset wells and nearby surface fissures was very slight to none. It was evident that an underground blowout was occurring at the base of the surface casing in Well 4-15-H with a continuous flow conduit through the talus of near-surface formations to the atmosphere. The well was flowing 100% CO_2 gas through the blow holes, with occasional softball-sized (about 1/3rd soccer-ball-sized) chunks of solid CO_2 spewing hundreds of feet into the air.

As stated at the start of this section, this well was brought under control in early April 1982 by the dynamic injection of drag-reduced brine followed by mud (after four unsuccessful attempts to kill the well with conventional weighted-mud techniques – see Section 6.3.1). A summary of the lessons learned from this blowout control incident are:

- *Although originally proposed as a technique to allow a blowout to be contained without breaking down subsurface formations, the dynamic kill method proved effective in this case where hydraulic constraints severely limited weighted-mud injection rates.*
- *The analytical techniques and assumptions (documented in the paper by Lynch et al, 1985) were, in general, valid. There were no observed phenomena that seemed to be unexplained and no apparent contradictions among analyses that were not resolved.*
- *Several types of data proved very valuable as inputs to the analyses and in calibrating their results. These included:*
    - *Caliper log data - If these had not been available, data from nearby wells would at least have indicated where washed-out zones might have occurred*
    - *Temperature logs - These were particularly important as they were used to determine flow regimes. These in turn were used in calibrating pressure-drop calculations*
    - *Reservoir data - Data such as reservoir temperature, pressure, porosity, and permeability were required to link the reservoir performance with the wellbore performance*
- *A high level of drag reduction was achieved in 10.5 lbm/gal (1260 kg/m^3) CaCl2 brine.*

Blowout No.5: Penn West Petroleum's 14-20 well (located about 6 km southwest of the town of Swan Hills, Alberta, Canada experienced a loss of well control (blowout).

Description of Incident

The blowout occurred on August 17, 2010 while repairing a surface casing vent flow on a dual string water and CO_2 injection well. A total of 850 cubic meters (m^3) of produced water, 2 m^3 of diesel fuel, and 103,000 m^3 of CO_2 was released from the well as a fine mist spray, impacting a total land area of approximately 105,000 square meters. Wellbore fluids sprayed both on and off lease and entered a watercourse located about 110 m north of the well. CO_2 readings ranged between 0 and 8,800 parts per million, depending on proximity to the well site and meteorological conditions. The incident occurred in a rural wooded area with no residences and received no media attention.

Well History

The 14-20 well was licensed as an oil well to Amoco Canada Petroleum. Penn West purchased the well from Amoco's successor in November 2002, and applied on May 5, 2008 to the Energy Resources Conservation Board (ERCB) for an injection well permit, which was granted in May 16, 2008.

Both water and liquid CO_2 were injected into the well through two tubing strings into one zone. CO_2 was injected into the lower part of the zone to stimulate production, and water was injected into the upper part of the zone to prevent vertical migration of the CO_2. The wellbore contains two packers: one near the bottom of the water injection string and one near the bottom of the CO_2 injection string. The tubing and production casing annulus was filled with diesel for corrosion and freeze protection purposes.

Pertinent Operator Activities at the Well

A packer isolation test conducted by the Operator on August 19, 2009 failed, indicating that either a packer or the production casing had been compromised. The Operator did not repair the failure or report it to the ERCB. On July 14, 2010, the surface water injection line had failed due to internal corrosion. The Operator continued injecting CO_2 until the well was shut-in on August 16, 2010.

Cause of the Loss of Well Control

The ERCB concluded that the following sequence of events led to the release:

(1) *Top packer failure in 2009 allowed CO_2 into the wellbore.*

(2) *Production casing failure at approximately 60 m from surface. Although a metallurgical analysis could not definitely identify the cause of failure, it is surmised that a combination of factors contributed to the production casing collapse including the heating/cooling cycles involved with*

injecting water and CO_2 and associated tensile stresses and indication of some external corrosion at the failure point.

(3) *On August 16, subsequent to the production casing failing, wellbore fluids were released to surface from the surface casing vent and resulted in a surface casing vent discharge. A service rig was then placed on the well.*

(4) *The initial release of wellbore fluids left the annulus partially empty. Once on site, the service rig filled the annulus with a mix of methanol and fresh water. Calcium chloride was then pumped down both tubing strings. During this time, no discharge was seen from the surface casing vent.*

(5) *After removing the wellhead and installing a blowout preventer (BOP), the short tubing string was unlatched from the failed top packer. There was an immediate discharge of fluid from the surface casing vent. This resulted in a further loss of hydrostatic pressure in the annulus allowing the CO_2 to enter the annulus through the packer with the tubing string removed causing a substantial increase of flow into the wellbore.*

(6) *The Operator closed the pipe rams on the BOP, but the breach in the production casing allowed wellbore fluids from the annulus to escape through the surface casing vent to surface and control of the well was lost.*

Enforcement action was taken by ERCB against the Operator for failing to perform timely repairs and failure for timely reporting upon detection. The Operator successfully addressed the enforcement actions on February 17, 2011.

Here are some additional well control/blowout incidents related to CO_2 EOR wells that have been reported in the press:

- *Tabula Rasa Energy's Essau 56-W oil well had an uncontrolled release of CO_2 and H_2S to the atmosphere on December 8, 2015. The well is located in Gaines County, Texas and about 4 miles (6.44 km) east of Seminole and led to the evacuation about 400 people. A pulling unit was on site in preparation for a workover when the incident happened. ("Witnesses familiar with oilfield equipment told NewsWest 9 that the well had a "surface casing rupture" and "flowback issues"). Carbon dioxide reportedly "froze the flowback equipment" and led to a buildup of pressure with high CO_2 and H_2S concentrations) – http://www.newswest9.com/story/30695088/oil-well-blowout-reported-in-gaines-county). The East Seminole (San Andres) Field was undergoing EOR operations injecting CO_2 to recover incremental oil. A relief well was drilled and the well brought under control a week later (Seminole Sentinel, 2015).*

- *Denbury's CO_2 EOR operations in Mississippi resulted in an uncontrolled release at an offset abandoned well in Yazoo County in 2011(Associated Press, 2013). The old abandoned well had its casing removed and the 2,000 foot (610 m) deep hole vented CO_2, oil and drilling mud for 37 days starting August 9, 2011. The released CO_2 settled in some hollows, suffocating deer and some other animals. The operator ultimately drilled a relief well and stopped the release. The operator paid a fine of $ 662,500 to the Mississippi Department of Environmental Quality.*

6.3.1 Dynamic Kill Technology

A dynamic kill is a technique for controlling a blowout without the use of highly overbalanced kill fluids. The technique uses both the flowing frictional pressure drop and the hydrostatic pressure drop of a kill fluid that is injected near the bottom of the blowing well, thus allowing a lighter kill fluid to be used. This factor becomes increasingly important if flow restrictions – such as small-diameter tubulars in the case of Well 4-15-H – limit fluid injection. The injected fluid rate must be large enough so that the sum of the frictional and hydrostatic pressures exceeds the static formation pressure. This rate must then be sustained until a heavier static-kill mud displaces the lighter dynamic-kill fluid.

In the design of a dynamic kill operation, the following factors are of primary importance:

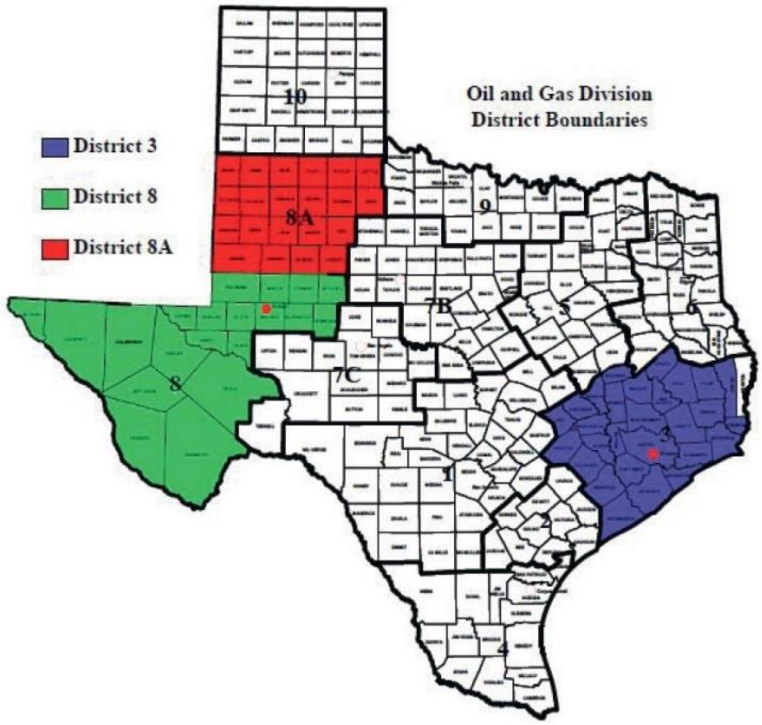
1. *An accurate value for the static bottom hole pressure for the reservoir.*
2. *A good understanding of the pressure and hydraulic constraints. The operating pressure was limited to 5,900 psi (40.7 MPa) by the 4 ½ inch (11.4 cm] 16.6 lbm/ft (24.7 kg/m) Grade E drill pipe. Because of the small IDs through both the bottom hole assembly (BHA) and approximately 1,200 feet (370m) of the 4½ inch (11.4 cm) heavyweight drill pipe (2$^{3/8}$ inch (6 cm)ID), frictional pressure losses would be extremely high. The BHA was shot and severed at 3,517 feet (1072 m) MD to eliminate the frictional pressure losses that would have resulted from pumping through the rock bit jet nozzles.*
3. *Deliverability of the well. The deliverability of the well depends on the characteristics of the reservoir and the hole. Data such as reservoir temperature, pressure, porosity, and permeability are required to link the reservoir performance with the wellbore performance (wellbore geometry).*
4. *Kill fluid density and injection rate. For a given injection piping geometry and drill pipe pressure limit, the selection of kill-fluid density is a trade-off between the advantages (higher hydrostatic and friction pressure drops in the annulus) and disadvantages (higher friction losses in the injection piping, which tend to reduce the injection rate) of high density. Further, the use of friction reducers must be approached with care; if the friction in the annulus were also decreased, there might be no significant benefit.*

Depending on circumstances, new wells can also be killed using conventional weighted mud techniques by bull heading it down drill pipe, reservoir and fluid mechanical conditions permitting. For completed wells, weighted mud or brine can be bull headed down the tubing string to kill a well.

6.4 WELL BLOWOUTS AND IMPLICATIONS FOR CO_2 STORAGE WELLS

Porse et al (2014) studied the blowout frequency for three regions in Texas. Texas was chosen because it is the world's largest producer of CO_2 EOR oil, and is the most prolific conventional oil and gas producer in the United States. The study uses data from three geographic areas, Texas Railroad Commission (RRC) Districts 3, 8 and 8A (Figure 13).

Figure 13 - Texas Railroad Commission Oil and Gas Division Districts Map (Porse et al, 2014)



Districts 3, 8 and 8A were chosen because they represent operational and geographical dichotomies. Districts 8 and 8A are located primarily in the Permian Basin in West Texas while District 3 is located in southeast Texas along the Texas Gulf Coast. District 8 had the highest overall oil and gas activity during the period 1998-2011 and Districts 8 and 8A have the highest number of active CO_2 EOR injection wells in Texas with 978 and 1,016 wells respectively. In contrast, District 3 has only 35 currently active CO_2 EOR injection wells. While Districts 8 and 8A produced more oil, operators in District 3 produced more natural gas during the period 1998-2011 than Districts 8 and 8A combined.

<u>Data Analysis Results</u>

As of March 2014, there were 616 recorded blowouts in the selected Districts from 1942 to 2013 in the RRC database. Table 9 gives the breakdown of blowouts by operational activity for the period 1998-2011. The largest category for Districts 3, 8 and 8A were 29 (drilling), 28 (drilling) and 11 (production operations).

Table 9 - Texas RRC Blowouts, 1998-2011 (Porse et al, 2014)

Development Stage	District 3	District 8	District 8A
Drilling	29	28	7
Completion	9	5	6
Workover	7	7	9
Production/Operations	19	3	11
Injection	0	1	0
Shut-in	0	0	1
Plugging	6	1	0
Abandoned	1	0	0
Other	3	2	1
Uncategorized	1	2	0
District Total	**75**	**49**	**35**

The highest frequency of blowouts for any given District barely exceeded 0.5% of the overall population totals for wells at a given stage. For District 3, drilling was the riskiest stage while in Districts 8 and 8A, workovers had the highest risk. It should be noted that shut-in data could not be quantified since RRC shut-in records could not be organized by date of shut-in.

Jordan et al (2009) also studied blowout incidents in oil field undergoing thermal (steam-flood) EOR in California District 4 during the period 1991-2005. Data from 102 blowouts was analyzed for the period 1991 – 2005. District 4 produces 75% of California's oil production, principally through thermal (steam-flood) enhanced oil recovery techniques.

Also, Loss of Control (LOC) incidents including blowouts in the Gulf of Mexico are discussed in API Standard 65-2 – Section 15.1 Annex 1.

<u>*Summary of conclusions by Porse et al (2014), Jordan et al (2009), Skinner (2003) and API Standard 65-2:*</u>

- *Although the study indicated the frequency of blowouts is very low, the public may have a negative perception of the risks from blowouts leading to a "Catch 22" situation. While industry goes to great lengths to avoid well blowouts, it is reluctant to share information about prevention measures and incident details in the rare instances when they occur.*

- *Need to implement improved data reporting for well control/blowout incidents to regulatory agencies. The following data should be reported and managed in the database related to blowout* *incidents: date, time and duration of incident; location (latitude/longitude, township, range, lease area); description of any leak(s) by fluid type; estimated fluid volume(s); and description of any known human, property or environmental impacts.*

- *Frequency of blowouts in California's District 4 decreased dramatically during the period 1991-2005 and is believed to be a result of increased experience, improved technology and/or changes in the safety culture in the oil and gas industry. This suggests that blowout risks can also be lowered in CO_2 storage fields.*

- *Additional studies in fields including natural gas storage fields with higher pressures, flow rates and CO_2 injection are needed to verify these conclusions.*

- *The API study that looked at 14 of the 19 LWC incidents (annular flows) that occurred during or after cementing operations in the U.S. Outer Continental Shelf (OCS) showed that:*

    - Most of the LWC incidents took place during or after cementing surface casing.
    - In more recent years (2003-2004), these events involved deep casing strings with no occurrence of LWC incidents in surface casing cementing operations.
    - Most wells used a mudline hanger/suspension system.
    - Frequently the annulus between the surface casing and conductor casings was washed out to a point 30 feet to 50 feet below mudline after cementing. Washing out this annulus resulted in a small but possibly very significant reduction in the hydrostatic pressure while also impairing the operation of the BOP and diverter (wash pipes in the annulus prevents sealing).
    - Often, cement slurries were not designed to prevent flows.
    - Effective drilling fluid removal and zonal isolation practices were not followed

- *Findings from the Case Studies of the Blowouts presented in this Report (Section 6.3) show the following:*

    - Blowouts in gas producers containing high concentrations of CO_2 have occurred during drilling/production operations including well control problems in CO_2 source production wells in New Mexico, Colorado and Wyoming.
    - CO_2 blowouts may have complications that other blowouts may not exhibit, due to the characteristics of CO_2. The tremendous expansion of supercritical CO_2 when pressure containment is lost is of great significance from a well control perspective.
    - Flow through small openings (holes in casing, leaks around pipe rams or in the wellhead etc.) can reach sonic velocity, limiting flow rate and consequently, CO_2 influx from the reservoir into the wellbore. This flow behavior is almost explosive in its violence, and usually not expected by field/rig workers. Often, only a small volume of supercritical CO_2 in the wellbore is enough to trigger the process, causing the well to blowout in a matter of seconds. Reaction time is minimal and some equipment, particularly manual BOP's and stab-in safety valves, cannot be installed

and closed fast enough to avoid complete liquid expansion from the well and total loss of well control.

- The second process that occurs simultaneously when pressure containment is lost is the rapid cooling of wellbore and fluid streams due to expansion, and the formation of dry ice once the CO_2 stream falls below the triple point. Problems that arise from this unique CO_2 phase behavior include: (1) high flow rates complicates surface intervention work and exposes workers to gas moving at high velocities; (2) CO_2 and produced fluids form hydrates that collect in BOP's, wellhead and other surface equipment; (3) the cold CO_2 condenses water in the atmosphere, resulting in reduced visibility in the white "cloud" around the wellbore; and (4) free oil and condensed miscible fluids swept out of the near wellbore area can collect on the surface, creating a ground-fire hazard. Further, dry ice formation results in pea-to marble-size projectiles expelled at very high velocities.

- Unlike oil and gas blowouts, where fire is the major concern, in CO_2 blowouts asphyxiation is the major concern, since CO_2 is heavier than air, with a specific gravity of 1.55 (Air = 1.0). It can collect in high concentrations in low areas such as depressions, pits and cellars. Depending upon the level of potential risk, it may be appropriate to have self-contained breathing apparatus (SCBA) on-site and available during CO_2 injection well drilling or intervention procedures (Contek/API, 2008).

- Failures from CO_2-related corrosion can cause the loss of well control. In some wells in CO_2 floods that were drilled in the 1940s and 1950s, cumulative corrosion impacts are a problem. It is important to make older wells equipped with corrosion-resistant tubulars and also wells that have been converted to CO_2 service.

- The dynamic kill technique can be used to control a CO_2 blowout without the use of highly overbalanced kill fluids. This factor becomes important if flow restrictions, such as small diameter tubulars, limit fluid injection and rate.

7.0 REGULATORY FRAMEWORK FOR CO_2 EOR AND CO_2 STORAGE WELLS

7.1 REGULATORY FRAMEWORK FOR CO_2 INJECTION WELLS IN THE U.S.

The U.S. Environmental Protection Agency (EPA) is mandated under the Underground Injection Control (UIC) Program of the Safe Drinking Water Act (SDWA 1974) to protect Underground Sources of Drinking Water (USDW) and the health of persons from underground injection. A USDW is any aquifer or portion of an aquifer that contains water that is less than 10,000 parts per million (ppm) total dissolved solids, or contains a volume of water that is either presently a source or in the future a viable source for a Public Water System. EPA directly implements the UIC program in 9 states, 34 states have primary enforcement authority and EPA and States share UIC program implementation in 6 states.

EPA has classified all injection wells into six (6) Classes I through VI. Class I wells are generally deep and stringently regulated with detailed well construction, siting, monitoring and closure requirements and include wells that inject hazardous fluids, industrial fluids and municipal wastewater. Class II wells are used by the exploration and production (E&P) sector of the oil and gas industry for produced brine and waste fluid disposal (drill cuttings, muds etc.), enhanced oil recovery (EOR), and hydrocarbon storage. Class III wells are associated with solution mining (uranium, copper, sulfur, salts), Class IV wells are used to inject hazardous or radioactive wastes into or above a USDW (and are prohibited), while Class V wells include all other wells that do not fall under Classes I through IV. The Class VI category was established by EPA in December 2010 and applies for storage of CO_2 in deep rock formations.

Class II CO_2 EOR Wells

Wells that will be used for CO_2 EOR will continue to be regulated under the Class II category. The Class II category includes: disposal wells, enhanced recovery wells, and hydrocarbon storage wells. The number of active Class II wells varies from year to year based on fluctuations in oil and gas demand and production. Approximately 184,000 Class II wells are in operation in the US (see Table 11), with more than 730 billion gallons (2.76 billion m^3) of fluid injected each year (https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells). Class II disposal wells that inject produced oil field brines brought to the surface in conjunction with oil and gas production represent about 20% of the total number of Class II wells while Class II EOR wells represent about 80% of the total Class II well universe of about 150,000 active wells with about 13,000 CO_2 EOR wells operating in the U.S. The number of CO_2 EOR wells is sparse in the rest of the world.

Definition of Class II Enhanced Recovery Wells: "Class II EOR wells inject fluids consisting of brines, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and in limited applications, natural gas". The Underground Injection Control (UIC) program does not regulate oil and gas production wells (which are regulated by state oil and gas regulatory agencies) that are solely used for production.

It should be noted that natural gas storage injections are statutorily excluded from the definition of 'underground injection' under the SDWA (pursuant to a 1980 amendment). Thus, the SDWA does not govern the subsurface injection and storage of natural gas, but does apply to the injection and storage of CO_2.

EPA regulates the injector wells in CO_2 EOR projects except when State regulators claim "primacy" over the EPA's authority. In order to qualify for primacy, the State rules must be equal to or greater than the EPA's rules. See more on this subject at: https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells

Class II Well Requirements: States (including federally recognized tribes and U.S. territories) have the option of requesting primacy for Class II wells under either Section 1422 or 1425 of the Safe Drinking Water Act (SDWA), which was passed by Congress in 1974.

Under Section 1422 states must meet EPA's minimum requirements for UIC programs and Class II EOR Wells may either be issued permits or be authorized by rule, with disposal wells requiring approved permits prior to initiation of injection. The owners/operators of the wells must meet all applicable requirements, including strict construction and conversion standards and regular inspection and testing. Programs authorized under Section 1422 must include well owner and operator requirements for:

- *Construction*
- *Operating*
- *Monitoring and testing*
- *Reporting*
- *Closure requirements*

Under Section 1425 states must demonstrate that their existing standards are effective in preventing endangerment to underground sources of drinking water (USDWs – zones/aquifers that have equal to or less than 10,000 mg/l of total dissolved solids and are capable of being a public water supply source). These programs must include requirements for:

- *Permitting*
- *Inspections*
- *Monitoring*
- *Recordkeeping and Reporting*

A good example of the early CO_2 injection well construction practices can be found in the EPA document titled "Injection Well Construction and Technology" published by the EPA in October, 1982. See more on the subject at: https://www.epa.gov/uic/underground-injection-control-regulations-and-safe-drinking-water-act-provisions

The official rules of the Railroad Commission of Texas (RRC) are found in the Texas Administrative Code (TAC), Title 16, Part 1, Chapters 1through 20 (http://www.rrc.state.tx.us/general-counsel/rules/current-rules/

Relevant regulations for Class II EOR wells (that includes Class II CO_2 EOR wells) for the state of Texas which has primacy for the implementation of the UIC program by the Texas Railroad Commission (RRC) are given in Chapter 3 – Oil and Gas Division and Chapter 4 – Environmental Protection and include:

RULE §3.13 Casing, Cementing, Drilling, Well Control and Completion Requirements

RULE §3.46 Fluid Injection into Productive Reservoirs (includes mechanical integrity testing requirements)

RULE §3.14 Plugging

Table 10 below gives the Year 2016 inventory by state of Class II wells in the U.S. and includes both disposal and injection wells.

Table 10 - USA Underground Injection Control Class II Inventory - Year 2016 Summary

State in USA	Class II Disposal Wells	Class II EOR Wells
NY	*6*	*322*
PA	*15*	*1764*
VA	*13*	*3*
WV	*67*	*606*
AL	*94*	*164*
FL	*20*	*48*
KY	*109*	*2885*
MS	*578*	*740*
TN	*2*	*24*
IL	*1100*	*6964*
IN	*215*	*999*
MI	*812*	*701*
OH	*2233*	*128*
AR	*836*	*256*
LA	*3195*	*557*
NM	*951*	*3420*
OK	*4400*	*6827*
TX	*13418*	*40421*
IA	*7*	-
KS	*5039*	*11724*
MO	*10*	*442*
NE	*154*	*498*
CO	*373*	*569*
FP	*26*	*4*
MT	*261*	*977*
ND	*591*	*762*
SD	*41*	*41*
UT	*87*	*709*
WY	*479*	*4519*
CA	*1794*	*54102*
Navajo	*18*	*344*
NV	*12*	*5*
AK	*49*	*1449*
WA	*1*	-
Tribes	*1163*	*2733*
Grand Total	**38169**	**145707**

Class VI CO_2 Geologic Storage Wells

Definition of Class VI Wells: "Class VI wells are used to inject carbon dioxide (CO_2) into deep rock formations. This long-term underground storage is called geologic sequestration (GS). Geologic sequestration refers to technologies to reduce CO_2 emissions to the atmosphere and mitigate climate change".

Geologic sequestration is the process of injecting CO_2, captured from an industrial (e.g., steel and cement production) or energy-related source (e.g., a power plant or natural gas processing facility), into deep subsurface rock formations for long-term storage. This is part of a process frequently referred to as "carbon capture and storage" or CCS. Underground injection of CO_2 for enhanced oil recovery (EOR) and enhanced gas recovery (EGR) is a long standing and well established practice in the U.S. CO_2 injection specifically for GS involves different technical issues and potentially much larger volumes of CO_2 and larger scale projects than in the past.

The regulations address some of the unique challenges presented by injection of CO_2 for long term geologic storage purposes. These include: relative buoyancy of CO_2, its corrosiveness particularly when present with water, potential impurities that may be entrained in the captured CO_2, mobility of CO_2 in underground formations, and very large injection volumes that are anticipated once carbon capture and storage (CCS) technology is fully deployed.

<u>Class VI Wells Requirements address:</u>

- *Siting*
- *Construction*
- *Operation*
- *Testing*
- *Monitoring*
- *Closure*

EPA developed specific criteria for Class VI wells:

- *Extensive site characterization requirements*
- *Injection well construction requirements for materials that are compatible with and can withstand contact with CO_2 over the life of a GS project*
- *Injection well operation requirements*
- *Comprehensive monitoring requirements that address all aspects of well integrity, CO_2 injection and storage, and ground water quality during the injection operation and post-injection site care period*
- *Financial responsibility requirements assuring the availability of funds for the life of a GS project (including post-injection site care and emergency response)*
- *Reporting and recordkeeping requirements that provide project-specific information to continually evaluate Class VI operations and confirm USDW protection*

One of the key characteristics of CO_2 EOR operations is that the governing rules effectively prohibit the geologic storage of more CO_2 than is used and incidentally stored in the EOR operations, since the authorization of a Class II permit only extends to oil and gas operations. Hence, under the Class II UIC rules CO_2 injection and storage operations must come to a close with the termination of the EOR operation. The EPA's new Class VI rule of 2010 provides owners or operators injection depth flexibility in different geologic settings across the U.S. and the flexibility includes deep formations and oil and gas fields to transition to incremental storage in the same formation.

The Texas Railroad Commission (RRC) has been authorized to run the Class VI CO_2 injection well UIC program for geologic storage and associated injection of anthropogenic CO_2 in the state of Texas. Relevant regulations are given in Chapter 5 – Carbon Dioxide (CO_2) and Chapter 4 – Environmental Protection and include:

RULE §5.102 General Provisions (Definitions)(Subchapter A)

RULE §5.203 Application Requirements (Subchapter B)

RULE §5.206 Permit Standards (Subchapter B)

RULE §5.302 Definitions (Subchapter C)

RULE §5.305 Monitoring, Sampling, and Testing Plan (Subchapter C)

RULE §5.308 Requirements for Certification (Subchapter C)

References:

https://epa.gov/uic/class-VI-wells-used-geologic-sequestration-CO_2

EPA Geologic Sequestration of Carbon Dioxide – UIC Program Class VI Well Testing and Monitoring Guidance, March 2013

http://www.rrc.state.tx.us/general-counsel/rules/current-rules/

Greenhouse Gas Reporting Program in the U.S.A.

In December 2010, the EPA finalized a rule under the authority of the Clean Air Act requiring all facilities that conduct geologic sequestration of CO_2 and all other facilities that inject CO_2 underground to report greenhouse gas data to the EPA on an annual basis. Information obtained under the Greenhouse Gas Reporting program will enable EPA to track the amount of CO_2 received by these facilities. The Reporting

Rule is complementary to and builds on EPA's UIC program, allowing any well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations to report. Facilities that conduct enhanced oil and gas recovery are not required to report geologic sequestration under Subpart RR unless:

- *The owner or operator chooses to opt-in to subpart RR; or*
- *The facility holds an EPA's UIC Class VI permit for the well or group of wells used to enhance oil and gas recovery and reports under Subpart UU.*
- *Furthermore, CO_2 EOR facilities may be required to report under Subpart RR if they are seeking to gain federal tax credits for the use of anthropogenic CO_2 for EOR.*

The Global Carbon Capture and Storage Institute (GCCSI) notes that only 17 CCS facilities are operating today with just five new facilities under construction. The U.S. budget recently approved by Congress (H.R. 1892 effective February 9, 2018) expands a tax credit granted in 2009 under Section 45Q that could potentially accelerate implementation of CCS and CO_2 EOR projects. The key provisions are that for stored CO_2, the tax credit rises to $ 50 per metric ton in 2027, while for EOR and other uses the tax credit is $ 35 per metric ton. This tax-credit expansion is expected to give a boost to both increase U.S. oil production from enhanced oil recovery while also giving an economic impetus for the underground long-term geological storage of CO_2, and a positive impact on reduction of greenhouse gas emissions.

7.2 REGULATORY FRAMEWORK FOR CO_2 INJECTION WELLS IN CANADA

CO_2 EOR is a primary policy, regulatory and legal driver for carbon capture, utilization and storage (CCUS) in Canada. Regulating resource development is the responsibility of the provinces, while the federal government is responsible for the regulation of cross-border issues such as climate change.

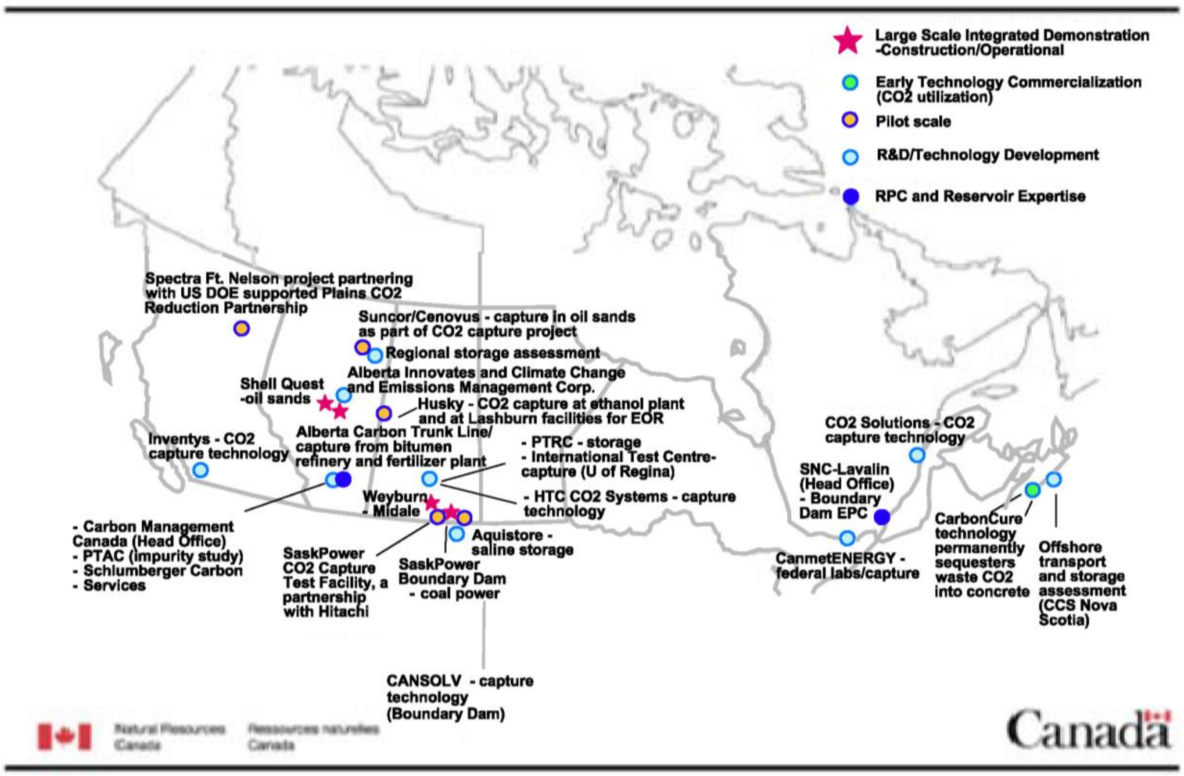
Therefore, the physical injection of CO_2 in a single province is under the purview of that particular province, while setting standards for what can or cannot be counted under provincial and federal CO_2 reduction targets will be a shared responsibility.

The Government of Canada and the provinces have been engaged in updating their existing oil and gas regulatory and CCS – specific frameworks. Figure 14 provides an overview of the current provincial CCS policy and regulatory development activity in Canada.

Figure 14 - CCS Policy and Regulatory Development in Canada (CCP4 Report)

Building on the technical and regulatory experience developed CO_2 EOR in the oil and gas sector over three decades, a number of related large CCS demonstration projects and pilot-scale research projects have been commissioned across the country. Specific to CO_2 EOR, it is understood that at least 195 CO_2 injection wells are reported to be active, the majority of which are associated with the Weyburn project in Saskatchewan. Figure 15 provides an overview of CCS development projects in Canada at the moment.

Figure 15 - CCS Development Projects in Canada (CCP4 Report)



Alberta presents a comprehensive regulatory framework for the oil and gas sector, administered by the Alberta Energy Regulator (AER) (which succeeded the Energy Resources Conservation Board - ERCB) on June 17, 2013), under the Oil and Gas Conservation Act. In addition, Alberta has a history of injecting substantial quantities of CO_2 into deep geological formations as part of acid gas disposal (AGD) in order to reduce atmospheric emissions of hydrogen sulfide (H_2S). The acid gas can contain up to 95% CO_2.

A CO_2 injection well in Alberta is classified as a Class III well. Class III wells are used for the injection of hydrocarbons, inert gases, CO_2 and acid gases for the purpose of storage or enhancing oil recovery from a reservoir matrix (AER directive 051). A Class III well is required to have cement across usable ground water, but there is no requirement to have surface casing below base of protected ground water. Some applicable Directives to the scope of this Study include: Directive 008 – Surface Casing Depth Requirements; Directive 009 – Casing Cementing Minimum Requirements; Directive 010 – Minimum Casing Design Requirements; Directive 013 – Suspension Requirements for Wells; Directive 020 – Well Abandonment; Directive 033 – Well Servicing and Completions Operations – Interim Requirements Regarding the Potential for Explosive Mixtures and Ignition in Wells; Directive 036 – Drilling Blowout

Prevention Requirements and Procedures; Directive 51 – Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements; Directive 059 – Well Drilling and Completion Data Filing Requirements; Directive 071 – Emergency Preparedness and Response Requirements for the Petroleum Industry; Directive 079 – Surface Development in Proximity to Abandoned Wells; Directive 080 – Well Logging; Directive 083 – Hydraulic Fracturing – Subsurface Integrity (https://www.aer.ca/rules-and-regulations/directives)

CCS – specific legislation has been developed in the form of the Carbon Capture and Storage Statutes Amendment Act 2010. Although this amends legislation that applies to certain types of oil and gas activities, CO_2 EOR is not explicitly addressed.

Although recent developments have focused on the regulatory framework as it applies to CCS projects, there is widespread recognition of opportunities stemming from the use of industrial CO_2 in EOR in Alberta, and the importance of encouraging their development. Opportunities stem from the dual benefits of CO_2 EOR projects: increased oil production, and the potential benefit of geological sequestration of anthropogenic CO_2. In Alberta, CO_2 EOR projects can gain recognition for CO_2 sequestration activities in the form of CO_2 offset credits under the Alberta Specified Gas Emitters Regulation (SGER). Projects wishing to gain credit for sequestered CO_2 must meet specific Measurement, Monitoring and Verification (MMV) requirements set out in the CO_2 EOR protocol for eligibility for CO_2 credits to ensure the viability of the long-term storage of CO_2.

As is the case in the Province of Alberta, Saskatchewan has over three decades of experience in the injection of CO_2 into the subsurface. There are reported to be in excess of 6,000 wells injecting various substances into subsurface reservoirs, all regulated under existing legislation: Saskatchewan Oil and Gas Conservation Act RSS 1978 (O&G Act). Current CO_2 storage operations in Saskatchewan were developed under the pre-existing oil and gas framework, amended in 2011, including the Weyburn project.

Complementing its neighboring provinces, British Columbia has a comprehensive oil and gas regulatory regime: the Petroleum and Natural Gas Act (P&NG Act) and the Oil and Gas Activities Act (OGAA). The more common activities occurring in this jurisdiction is the temporary storage of marketable natural gas and disposal of acid gas. Importantly, there are currently no explicit authorization provisions for CO_2 EOR projects, although it is not to say that the current regime is not sufficient to enable such an activity. Furthermore, the Ministry of Natural Gas Development is developing a regulatory policy framework for CCS. In summary, the regulatory framework is in place for EOR and CCS in Alberta and Saskatchewan and is being developed in British Columbia.

7.3 REGULATORY FRAMEWORK FOR CO_2 INJECTION WELLS IN E.U.

CCS activities in Europe are regulated under the 2009 EU Directive on the geological storage of carbon dioxide ('CCS Directive'), an instrument that is commonly understood to be one of the most comprehensive examples of CCS- specific legislation in the world. In support of the implementation process, delayed by lagged transposition by a number of Member States, the European Commission published four Guidance Documents in 2011:

- *Guidance Document 1: CO_2 Storage Life Cycle Risk Management Framework;*
- *Guidance Document 2: Characterization of the Storage Complex, CO_2 Stream Composition, Monitoring and Corrective Measures;*
- *Guidance Document 3: Criteria for Transfer of Responsibility to the Competent Authority;*
- *Guidance Document 4: Financial Security (Art. 19) and Financial Mechanism (Art. 20).*
- <u>*CCS Directive 2009/31/EC Review*</u>

In May 2014, the European Commission launched a consultative review process in order to assess the CCS Directive's effectiveness, relevance, efficiency, coherence and EU-added value.

With respect to the Directive itself, the following specific issues were highlighted:

- *The feasibility of retrofitting power plants for CO_2 capture;*
- *Emissions Performance Standards (EPS) for the role played by integrated transport and storage infrastructure in Europe ahead of establishing capture projects to maximize social benefits; and*
- *The definition of 'permanent' in the case of storage, transfer of responsibility for a storage site, financial security, financial mechanisms and the criteria for establishing and updating the monitoring plan.*

More recently, Member States were required to submit an Implementation Report to the European Parliament (EP) and European Council by 31 March 2015.

<u>*Application to CO_2 EOR and the EU ETS Directive*</u>

The EU Emissions Trading System (EU ETS Directive 2003/87/EC) has been amended by the European Commission to include the capture of GHGs from installations covered by this Directive 2009/31/EC (CCS Directive). This effectively means that installations undertaking a pure CO_2 storage activity must acquire an EU ETS permit and comply with the monitoring and reporting requirements, in accordance with the Directive;

There are not substantive provisions in relation to CO_2 EOR (Enhanced Hydrocarbon Recovery or 'EHR') in the CCS Directive. However, Recital 20 in the Preamble states the following:

"EHR is not in itself included in the scope of this Directive. However, where EHR is combined with geological storage of CO_2, the provisions of this Directive for the environmentally safe storage of CO_2 should apply. In that case, the provisions of this Directive concerning leakage are not intended to apply to quantities of CO_2 released from surface installations which do not exceed what is necessary in the normal process of extraction of hydrocarbons, and which do not compromise the security of the geological storage or adversely affect the surrounding environment.

There appears to be a consensus amongst commentators that the CCS Directive will apply to a CO_2 EOR project, provided that the CO_2 for the purposes of 'permanent storage' (i.e. incidental CO_2 storage during a conventional EOR operation) would be considered to be beyond the remit of the CCS Directive, and therefore, the EU ETS Directive. An existing EOR project wishing to obtain credit for the CO_2 stored would therefore have to retrospectively undertake the geotechnical assessments required for site evaluation and other activities in order to comply with the CCS Directive.

7.4 REGULATORY FRAMEWORK FOR CO_2 INJECTION WELLS IN U.K

The CCS Directive has been transposed under the Energy Act 2008, providing clear implementation guidance through the following supporting regulations:

- *The Storage of Carbon Dioxide (Amendment of the Energy Act 2008 etc.) Regulations 2011;*
- *The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010;*
- *2012 Regulations (amending the 2010 Regulations), which implement Article 15 of the CCS Directive on the inspection of carbon dioxide storage complexes*
- *Storage of Carbon Dioxide (Access to Infrastructure) Regulations 2011, which implement Articles 21 and 22 of the CCS Directive, on third party access to carbon dioxide storage sites and transport networks; and*
- *The Storage of Carbon Dioxide (Termination of Licenses) Regulations 2011, which implement Articles 18 and 20 on the transfer of responsibility for a closed storage site and the associated financial mechanism.*

In terms of Section 17 of the Act, a license is required for the use of a controlled place for the storage of carbon dioxide (with a view to its permanent disposal, or as an interim measure prior to its permanent disposal); or the conversion of any natural feature in a controlled place for the purpose of storing carbon dioxide (with a view to its permanent disposal, or as an interim measure prior to its permanent disposal).

Importantly, the wording of this section appears to be consistent with the CCS Directive, only including a CO_2 EOR project for the purpose of permanent storage, following the depletion of the oil-bearing reservoir.

Furthermore, in relation to the UK context, the UCL CCS Program Report referenced here, offers the following remark:

"In practice, at present at least, it seems likely that any proposed sites for EHR operations will in fact be already selected as CCS storage sites in accordance with the Directive, and these transitional issues or the need to secure exemption from the Directive are not an immediate issue"..

Finally, Section 33 of the Energy Act makes provision for the following discretionary authority:

The use of carbon dioxide, in a controlled place, for a purpose ancillary to getting petroleum is to be regarded as—

- *an activity within section 17(2); or*
- *the storage of gas for the purposes of section 1(3)(b), only in the circumstances specified by the Secretary ofState by order;*

Orders made under this section are without prejudice to Part 1 of the Petroleum Act 1998;

An order under this subsection may provide that the use of carbon dioxide, in a designated place, for a purpose ancillary to getting petroleum is to be regarded, for the purposes of this Chapter, as the use of carbon dioxide in a controlled place for such a purpose.

On the basis of the Explanatory Notes that accompany the Act and respective Regulations, it is understood that the intention is to use this power, for example, to ensure that the requirements extend to operators undertaking an EOR activity if those operators wish to claim credits under the EU ETS. This being said, the pursuit of emission credits is not the sole reason on which the CCS Directive may be considered to apply to a particular project.

7.5 REGULATORY FRAMEWORK FOR CO_2 INJECTION WELLS IN AUSTRALIA

In Australia, states and territories have jurisdiction over CCS activities onshore and up to three nautical miles offshore, beyond which jurisdiction is with the federal government. At the federal level, offshore storage of CO_2 is regulated through the 2006 Offshore Petroleum and Greenhouse Gas Storage Act (OPGGS Act), as amended by the Offshore Petroleum and Greenhouse Gas Storage Legislation

Amendment Act 2010. In 2011, the development of a set of Regulations under the OPGGS Act was finalized with the publication of the Resource Management and Administration Regulations 2011, and the Gas Injection and Storage Regulations 2011.

These regulations consolidate and streamline the various resources, administration, injection and storage-related requirements set out under the OPGGS Act.

Furthermore, dedicated CCS legislation exists onshore in the States of Victoria, Queensland, and South Australia. New South Wales and Western Australia are in the process of developing CCS legislation that is likely to be based on existing oil and gas regulations, as well as federal offshore CCS legislation.

The regulatory framework is in place for CCS but given the lack of EOR activities in Australia no explicit provisions for EOR or transition to CCS have been identified.

7.6 REGULATORY FRAMEWORK FOR CO_2 INJECTION WELLS IN BRAZIL

The state-owned oil company, Petrobras, has been conducting EOR activities for over two decades in accordance with Brazil's general environmental and oil and gas regulations. This has enabled the development of technological and geo-physical experience in CO_2 injection into offshore oil-bearing reservoirs. The commercial Lula Oilfield operation in the Santos Basin is such an example, and is further described in Section 8.1 (Case Study # 1) of this Report. Oil and gas related activities are generally required to comply with specific resolutions issued by competent governmental agencies, including, the Agência Nacional de Petroleo, Gas e Biocombustiveis (oil sector regulating agency). Resolution provisions include local content requirements or conditions and gas flaring reduction targets. It is understood that there are currently no Ministerial Resolutions providing specific guidance for a CO_2 EOR project to transition to permanent storage.

Furthermore, there is currently no legal or regulatory framework specific to CCS operations. However, the following developments are worth noting:

- *Brazil is a member of the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter and the 1996 London Protocol, as well as, Basel Convention on the Control of Transboundary Movements of Hazardous Waste and their Disposal;*
- *CCS is mentioned as a potential technology being developed by the oil and gas industry in the 2008 National Climate Change Plan (Plano Nacional de Mudança do Clima);*

- *The 2009 National Climate Change Policy (Política Nacional sobre Mudança do Clima) does not refer to specific technologies, but aims to incentivize the strengthening of emission reduction technologies and the promotion of carbon sinks;*

- *CCS is mentioned in the research and development plans under the Ministry of Science, Technology and Innovation (Petrobras research informs these plans);*

- *CCS is not explicitly mentioned in the 2015 Intended Nationally Determined Contribution to the UNFCCC and Brazil has opposed the adoption of CCS technology as a CDM modality. The country has, however, previously advocated for another framework using specific financial/funding mechanisms under the UNFCCC.*

In advancing the agenda for potential CO_2 sequestration in Brazil, the Center of Excellence in Research and Innovation in Petroleum, Mineral Resources and Carbon Storage (CEPAC) produced the 'Brazilian Atlas of CO_2 Capture and Geological Storage'. With the assistance of Petrobras and the Global CCS Institute, the Atlas Report represents the consolidation of nearly a decade of research and data gathering undertaken by specialist professionals/organizations since 2007. The research areas that have informed the content include the following:

- *Geological and mineralogical evaluation of storage reservoirs and reservoir interaction with CO_2;*

- *Investigation of the integrity and reliability of different materials and procedures applied to the injection of CO_2 through injection wells, in order to maximize the safety and feasibility of geological carbon storage;*

- *Studies of the geochemical interactions and flow mechanisms in the CO_2- water-rock system with focus on Brazil's pre-salt reservoirs; and*

- *Development of a Geographic Information System (GIS) containing data on CO_2 emissions resulting from stationary sources, transport infrastructure, and potential geological reservoirs.*

Overall, Brazil has a favorable situation regarding the potential for CO_2 geological storage. The country has a large area covered with sedimentary basins, both onshore and offshore. Most of the stationary emitting sources, especially in the Southeast region, are located in proximity to these basins;

The continental margin basins stand out as the main producers of hydrocarbons with the Campos Basin being one of the major producing areas. The Santos Basin will possibly continue to be a major area of hydrocarbon production in Brazil from 2025 when exploitation of pre-salt reservoirs will increase substantially. Further case reference is made to the Lula Oilfield Project located in the ultra-deep waters off Brazil's south-eastern coast.

CO_2 EOR is currently undertaken within existing petroleum legislation in Brazil. There is currently no CCS regulatory framework and therefore no structure in place for a transition from EOR to CCS in Brazil.

8.0 CASE STUDIES

8.1 CASE STUDY # 1: CO_2 INJECTION OFFSHORE – PETROBRAS'S LULA FIELD, SANTOS BASIN, OFFSHORE BRAZIL

Background

Brazil's Pre-Salt area is currently the international leader in pursuing deep water offshore CO_2 EOR. Lula was discovered in 2006 by Petrobras (Operator 65% with partners – BG E&P Brazil 25% and Petrogal Brazil 10%) in ultra-deep waters between 1,650 and 2,200 meters (5,400 to 7,200 feet), approximately 300 kilometers (180 miles) south-east of Rio De Janeiro. The Lula field encompasses the Tupi and Iracema areas in the Santos Basin Pre-Salt Cluster (SBPSC). Lula's carbonate reservoir (with an estimated 6.5 billion barrels of recoverable oil) is overlain by a thick 1,800 meters (6,000 feet) salt column and holds a moderately light, 28-30 degree API oil with a high solution gas-oil ratio. The associated gas in the reservoir contains 8% to 15% of CO_2.

This is an offshore (Santos Basin – Brazil) simultaneous CO_2 EOR and storage project in which CO_2 is captured in a pre-combustion stage at floating production, storage, and offloading (FPSO) vessels anchored in the Santos Basin. The captured CO_2 is injected at a rate of approximately 1 million tonnes (193 bcf) per year into the pre-salt carbonate reservoir at the Lula and Sapinhoa oil fields at a depth of between 5,000 and 7,000 m (16,400 – 23,000 feet) below sea level (Global CCS Institute 2016h). This project was designed as a CO_2 EOR project from its inception to avoid venting CO_2 to the atmosphere.

Brazil's Pre-salt trend differs significantly from the sub-salt trend found in the Gulf of Mexico. Pre-salt wells are drilled into formations that were deposited prior to the emplacement of a layer of autochthonous salt – salt that remains at its original stratigraphic level. By contrast, Sub-salt wells are drilled into formations lying beneath mobile canopies of allochthonous salt – masses of salt, fed by the original autochthonous layer, that rise through overlying layers then rise spread laterally. With the discovery of pre-salt reservoirs (e.g. Tupi), those targets in the strata above the salt are designated as Post-salt or Supra-salt prospects.

Drilling and wellbore construction challenges in the Pre-salt include:

- *The varying composition of the thick overlying evaporates (up to 7,000 feet – 2,134 m) can be difficult to drill. Each layer is characterized by different creep rates, which can vary as much as two orders of magnitude between the various types of salt. Salt creep can lead to wellbore restrictions, stuck pipe, torsional resistance and casing failure.*

- *The Pre-salt reservoirs consist of heterogeneous layered carbonates, which can adversely affect drilling progress.*

- *Geomechanical studies aid in anticipating potential for rock failure or salt deformation around the wellbore, in selection of drill bits and drilling fluids, and in devising mud, casing and cementing programs to extend wellbore integrity.*

- *Additionally, the corrosive environment presents a challenge due to the presence of significant amounts of CO_2 and H_2S, requiring special cements and metallurgies throughout the drilling and completion processes. Therefore, a broad scope of solutions are required including best practices along with lessons learned from previous Pre-salt drilling offshore Brazil, to reduce NPT (non-productive time) and avoid failures caused by the challenging salt formations.*

The complexity of implementing an offshore EOR project increases significantly with the move to ultra-deep waters. Since investments are normally huge, more appraisal and data acquisition is needed to reduce uncertainties and mitigate associated risks before sanctioning the project. Generally EOR methods require additional installation capabilities that can be a major constraint in an offshore facility (see Section 2.1.10 and Appendix A2.6). The uncertainty in reservoir property characterization is even more critical in carbonate reservoirs, which have a higher degree of heterogeneity than sandstones. The project is part of floating production, storage, and offloading (FPSO) units that incorporate CO_2 separation and injection facilities. It should be noted that CO_2 EOR was planned from the inception of this project so that the project design and implementation were rationalized from inception.

Lula CO_2 EOR Pilot Project Highlights

- Early Implementation of CO_2 EOR

Petrobras implemented a series of short-term EOR pilots at Lula with the intention of developing the entire field using CO_2 EOR, if the CO_2 pilot was successful. According to Petrobras, advantages of early implementation of CO_2 EOR as part of planned production were: improved capital efficiency since it freed the operator from subsequent retrofit of production systems and platform space for CO_2 recycling; and avoiding need to halt and/or shut-in production operations when implementing CO_2 EOR later in the field's life.

- Deepwater CO_2 EOR Technology

The technology deployed by Petrobras mirrors the methodology and design used in ARI's deep water resource assessment modeling and utilizes a hub and spoke model to service multiple fields with subsea completions. Also, the CO_2 EOR design utilizes intelligent well completions, dynamic downhole monitoring, tracer injections and extensive CO_2-recycling.

- Reservoir Characterization and Phased Development

Petrobras is executing a phased development of the Lula Field, allowing field development and EOR strategy to evolve as reservoir characterization and performance data is improved. The company uses Extended Well Tests (EWTs) to evaluate the wells' long-term production behavior, define reservoir connectivity and other key reservoir properties; production pilots to test recovery method performance and a phased development program to formulate their EOR strategy without waiting for results from the operation of a water flood.

The evaluation of flow in the reservoir can be made with either short-term (< 72 hours) drill stem tests (DST) or with extended well tests (~ 6 months) EWTs. EWTs are an excellent source of information on the dynamic performance of a well and surrounding reservoir. The "dynamic appraisal" method (Dake, 1994) can provide valuable information on the drainage plan and sweep strategy in the pre-salt.

- Selecting a Recovery Method at an early stage

Petrobras decided early in its field development cycle not to vent the CO_2 produced at Lula, but to use this gas for miscible CO_2 EOR. To achieve this, processing plants were equipped with a complex separation system, which removed the CO_2, compressed the CO_2 stream to a high pressure and re-injected the CO_2 into the producing reservoir. The CO_2 rich stream can also be mixed with a portion of the treated hydrocarbon gas for re-injection during EOR. In addition, the high CO_2 content present in the associated gas dictated that corrosion resistant alloys be used in all production wells enabling a CO_2 EOR flood to use existing wells and infrastructure without any refurbishment. A significant investment has been made in technology development, not only for the gas processing plant, but also for the subsea system, and well materials and equipment (Jorge Oscar Pizarro et al, World Oil, 2012).

Preliminary reservoir simulation studies showed that the oil recovery factor could be significantly improved with secondary and tertiary recovery, with water-oil relative permeability measurements showing reasonably high residual oil saturation. WAG injection was determined to be the best option given the two relatively abundant resources available: sea water and produced or imported gas. Some of the problems with WAG injection were also identified during the screening process: early breakthrough in production wells, reduced injectivity, corrosion, scale deposition, asphaltene precipitation and hydrate formation.

Injectivity tends to reduce after each cycle, due to the phenomenon of relative permeability hysteresis. In carbonate rocks, however, some field cases have shown injectivity increases, due to carbonate dissolution, because of the mixing between water and gas containing CO_2. Corrosion problems are not expected, since extensive use of CRAs has been adopted in the Lula wells, due to the presence of CO_2 in the original fluid. Studies are being done to handle asphaltene and hydrate formation.

- First Development Phase

The first Lula pilot consisted of one injection and one production well. In April 2011, Petrobras began injecting produced reservoir gas at a rate of 35 Mcfd (1Mm^3/d). After 6 months of gas re-injection, the hydrocarbon gas was separated from the CO_2 in the FPSO's membrane processing system and transported onshore for sale. The separated CO_2 was then re-injected into the reservoir at a rate of 12.3 Mcfd (0.35 Mm^3/d). A horizontal well was drilled in Q1 2012 and WAG injection, utilizing water and the high CO_2 concentration gas, commenced in the second half of 2012. The Lula EOR pilot included one gas injector, two WAG injectors, and multiple producers.

- *Reservoir Characterization*

Carbonate reservoirs are, in many aspects, much different than silica-clastics. Carbonates usually undergo more intense chemical diagenesis, which creates a heterogeneous reservoir system. Oil recovery is strongly controlled by horizontal and vertical connectivity with large permeability contrasts (high permeability layers) and the likely presence of fractures and faults (carbonates being less ductile). In the microscopic scale, heterogeneities in carbonates manifest in the form of flow barriers caused by cementation and presence of stylolites. The large permeability contrast also makes the capillary behavior of the porous system more important. Also, there is large vertical-to-horizontal anisotropy.

- *Simulation Modeling*

Numerical modeling and laboratory tests were done with water flooding as the base case, and CO_2 EOR and WAG cases. Compositional modeling showed potential for additional oil recovery above the water flooding base case with the low reservoir temperatures (60^0 – 70^0 C/140^0 - 158^0 F) and high original reservoir pressure enabling efficient miscible displacement of the oil by the injected hydrocarbon gas and CO_2 rich stream.

- *Operational Concerns*

Operational concerns included the possibility of hydrocarbon gas/CO_2 injection resulting in asphaltene and wax and hydrate formation. Depressurization in the risers causes gas to come out of solution, reducing flow temperature and increasing the possibility of wax deposition. Calcium carbonate scale is also an issue with CO_2 injection in carbonate rock. These potential flow assurance and integrity concerns including from corrosion are being addressed with the use of special alloys, plastic-covered pipes, and continuous downhole chemical injection, and special design of flexible flowlines and risers (Almeida et al, 2010). Controlling CO_2 is crucial not only to limit climate impact but also to reduce corrosion of equipment and deep sea pipelines caused by the mixture of CO_2 and water.

- Intelligent Completions

To improve reservoir management, intelligent completions are being deployed whenever considered beneficial. To be effective, it is desirable to have vertical isolation between zones in the reservoir. Being able to monitor bottom hole pressures and the use of chemical tracers in the injection fluid may provide important information to history match the production history and to calibrate the simulation models. This type of completion can mitigate the risk of preferential flow and early breakthrough, along with the option of being able to inject either water or gas, and lead to increased oil recovery.

8.1.1 Summary and Conclusions

Brazil's Pre-Salt is currently the international leader in pursuing deep water offshore CO_2 EOR.

- *Lula field discovered in 2006 with Petrobras as operator in ultra-deep waters between 1,650 to 2,200 m (5,400 to 7,200 feet). The Lula field encompasses the Tupi and Iracema areas in the Santos Basin Pre-Salt Cluster (SBPSC).*

- *Lula's carbonate reservoir (with an estimated 6.5 billion barrels of recoverable oil) is overlain by a thick 1,800 m (6,000 feet) salt column and holds a moderately light 28-30^0 API oil with a high solution-gas-oil ratio. The associated gas in the reservoir contains 8% to 15% CO_2.*

- *Brazil's Pre-salt trend differs significantly from the sub-salt trend found in the Gulf of Mexico.*

- *Drilling and construction challenges in the Pre-salt include:*

  - Varying composition of the thick overlying evaporates (up to 7,000 feet/2,134 m) can be difficult to drill. Creep rates can vary as much as two layers of magnitude between the various types of salt. Salt creep can lead to wellbore restrictions, stuck pipe, torsional resistance and casing failure.

  - Geomechanical studies aid in anticipating potential for rock failure or salt deformation around the wellbore, in selection of drill bits and drilling fluids, and in devising mud, casing and cementing programs.

  - Corrosive environment presents a challenge due to the presence of significant amounts of CO_2 and H_2S, requiring special cements and metallurgies throughout the drilling and completion processes.

- *Complexity of implementing an offshore EOR project increases significantly in ultra-deep waters*

- *Uncertainty in reservoir property characterization is even more critical in carbonate reservoirs which have a higher degree of heterogeneity than sandstone reservoirs.*

- *The project is part of floating production, storage, and offloading (FPSO) units that incorporate CO_2 separation and injection facilities*

- *Advantages of early implementation of CO_2 EOR as part of planned production included: improved capital efficiency since it freed the operator from subsequent retrofit of infrastructure and platform space, avoiding need to suspend or shut-in production.*

- *The CO_2 EOR design utilizes intelligent well completions, dynamic downhole monitoring, tracer injections and extensive CO_2 recycling.*

- *Numerical modeling and laboratory tests were done with water flooding as the base case, and CO_2 EOR and WAG cases. Low reservoir temperatures (60^0 – 70^0 C) with high original reservoir pressure shows efficient miscible displacement of the oil based on compositional modeling*

- *Petrobras has adopted a phased approach and decided early on not to vent the CO_2.*

- *Operational concerns include the possibility of wax/asphaltene deposition and hydrate formation. Calcium carbonate scale is also an issue. These potential flow assurance and corrosion concerns are being addressed with the use of special alloys, plastic-covered pipes, and continuous downhole chemical injection and special design of flexible flowlines and risers*

- *To improve reservoir management, intelligent completions are being deployed whenever considered beneficial. This approach can mitigate risks from preferential flow and early breakthrough and also allow injection of either water or gas.*

- *With the success of the pilot CO_2 EOR project (first stage from 2011-2017) in the Lula field, Petrobras has demonstrated that CCS and CO_2 EOR technology can be successfully combined for large-scale, sustained oil production, in extreme deep water applications.*

8.2 CASE STUDY # 2: NATURAL CO_2 RESERVOIR, BEĈEJ FIELD, SERBIA

Background and Introduction

The Beĉej field is located in the southeastern part of Pannonian basin, in the northern part of Serbia, partly below the city of Beĉej (Figure 16). The field is one of the largest natural CO_2 fields in Europe and was discovered in 1951 by the Petroleum Industry of Serbia (NIS).

Figure 16 - Location of Beĉej CO_2 Field, Serbia

A blowout occurred on November 10, 1968 during drilling of well Bc-5. Uncontrolled leakage lasted 209 days, till June 6, 1969, when the borehole collapse and killed the well. Vertical gas migration from the main CO_2 pool into the overlying aquifers in the overburden however continued, and because of the populated areas in the vicinity, the overlying confined aquifers and the uppermost unconfined aquifer for water supply, were closely monitored for gas migration. The monitoring network comprised: (i) more than 30 wells with depths in the range of 10 to 300 m, within a radius of 1,000 m around well Bc-5, and (ii) 2 deep wells (Bc-X-1 and Bc-X-2) for formation pressure measurements at depths from 740 to 850 m.

During the period 1968 to 1997 (39 years since the blowout occurred), reservoir pressure steadily declined at a rate of about 1 bar/year, despite there being no CO_2 production until after 1986 and the produced CO_2 volumes since 1986 being very small (~ $35x10^6$ m^3/year). Analyses of the production and monitoring data clearly indicated that the drop in formation pressure could largely be attributed to the vertical migration of CO_2 in the collapsed well. The estimated amount of gas that migrated from the main CO_2 pool into the shallow aquifers in the overburden was possibly ten times higher than the volume of CO_2 produced from the main reservoir. This led to the conclusion that the problem of unwanted gas migration could not be solved by conventional well treatment or workover techniques. In order to control and stop the CO_2 migration, a series of activities were undertaken by NIS that finally led to remediation operations in 2007.

Experiences and lessons learned from the Beĉej field case are currently studies within the MiReCOL project (Mitigation and Remediation of CO_2 Leakage). The project aims at developing a handbook of corrective measures, which can be considered in the event of significant irregularities and leakage from a CO_2 storage site. The Beĉej field case is particularly interesting and relevant because it represents the first known field application of remediation measures deployed to remediate leakage from a natural CO_2 reservoir – a natural analogue for a large-scale engineered geological CO_2 storage site.

The objective of the work performed by Karas et al (2016) was to perform a comprehensive geological characterization of the Beĉej field and construct an accurate static Petrel model of the reservoir and the overburden. The static model serves as a starting point for further research on CO_2 mitigation and remediation actions applied to the Beĉej field. The paper also describes remediation of the well leak and the most recently collected monitoring data, confirming that the remedial actions taken in 2007 were successful.

Geological Overview of the Beĉej Field

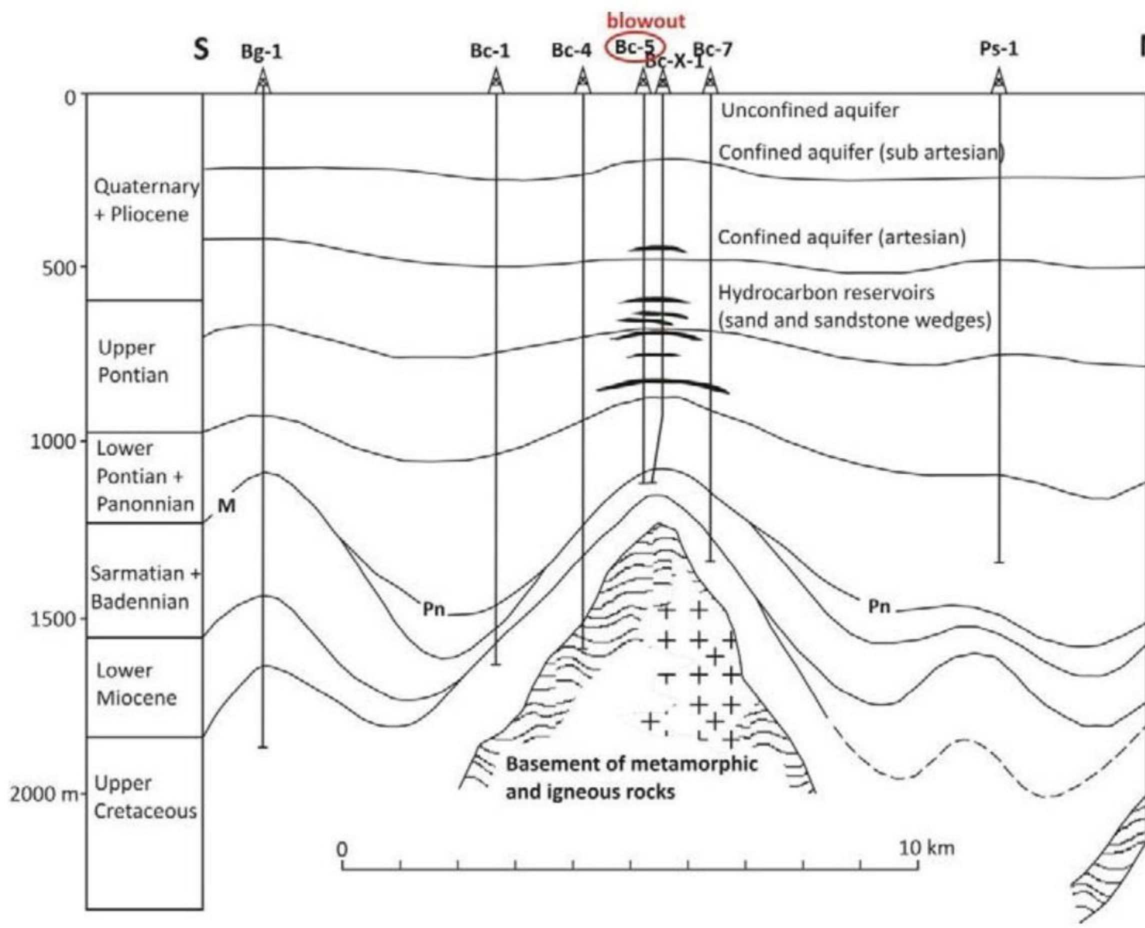
Geological setting and stratigraphy

The geological structure of the Beĉej field is complex. The main CO_2 pool is formed in the massive heterogeneous reservoir of Upper Cretaceous flysch and Badennian sand and limestone deposits. The reservoir is situated along a regional fault zone, and its structure was formed by a felsic igneous rock intrusion. This intrusion, according to the current hypothesis, has become a source of carbon-dioxide through the processes of metamorphism.

The following stratigraphic units are determined (in order from youngest to oldest; Figure 17):

- *Quaternary and Pliocene (Q + Pl)*
- *Pontian (M32) Upper Miocene*
- *Badennian (M21) Middle Miocene*
- *Upper Cretaceous (K2)*
- *Felsic igneous rock of undefined Paleozoic age.*

Figure 17 - South-north regional cross-section of the Beĉej field



Reservoir

The top of the main Badennian CO_2 reservoir is at a depth of about 1,100 m TVD. The initial reservoir pressure was 151 bar (2,190 psi) and the reservoir temperature is 87^0 C (188.6^0 F)

Overburden

The overburden comprises multiple shale and sandy layers acting as seals, semi-permeable layers and saline and fresh water aquifers. Sediments above the reservoir are of Lower Pontian age and unconformably cover Badennian sediments.

The Upper Pontian and Pliocene sandstones and sands have great significance as very porous and permeable rocks saturated with hydrocarbon gasses and geothermal groundwater. On the basis of seismic interpretation, a total of eight small hydrocarbon reservoirs have been identified at depths ranging between 450 to 900 m.

Besides hydrocarbon reservoirs, an important mineral resource is geothermal ground water since the history of using thermal waters in Beĉej is long. All the geothermal wells are artesian flowing wells because they are tapping confined aquifers saturated with water and gas, dominantly methane. Water from aquifers at a depth of 400 m has a temperature of 35°C and has been used for drinking and bathing in Beĉej spa for more than 100 years. The deep wells provide waters of 60 to 65°C for space heating of the hotel and sport center in Beĉej.

Structural Setting

The Beĉej field is confined within a four-way dip closure on top of a regional fault zone. The structure was formed by a felsic rock intrusion, which generated hydrocarbons and CO_2 in the processes of metamorphism. The basement and the overlying sediments are intersected by a few generations of faults and fractures extending near to, or up to, ground surface level. The position of faults, characteristics and areal distribution were determined on the basis of seismic interpretation. The presence of faults and fractures, and several accumulations of methane and possibly CO_2 in the shallow overburden, suggest that the Beĉej CO_2 field is a naturally leaking CO_2 system.

Static Model

Available data from different sources was used to construct a static model of the Beĉej field. The static model contains a reservoir model of the main CO_2 pool within the Badennian and the most important aquifers in the overburden of the Pontian and Pliocene. Input data available for modelling included: 27 interpreted 2D seismic profiles, well logging data from 18 wells, petrophysical interpretation of well logging data, data from cores and cuttings, and well test results.

The petrophysical interpretation of the well logging was performed to derive the rock properties for the main Badennian reservoir and the aquifers in the overburden. The key properties derived are the net thickness, shaliness, porosity, permeability and water saturation. The range of porosity values is from 12 to 26% and permeability values from 2 to 50 md. The gas-water contact within the Badennian and partially in the Cretaceous is assumed at a depth of 1,225 m TVD.

Remediation Measures

Remediation measures were deployed by NIS in 2007 to slow down or stop the leakage of CO_2 from the Beĉej natural CO_2 field. The evidence of continuous leak of CO_2 from the main pool since the 1968 well accident was a continuous drop in formation pressure in the main CO_2 reservoir, and the elevated pressures and concentrations of CO_2 in the aquifers above the main pool. Increased concentrations of CO_2

measured in wells Bcj-1 and Bcj-2 are attributed to the uncontrolled migration of CO_2 into the overburden after the well blowout (Table 11). The presence of methane is however unrelated to the well incident as accumulations of methane are commonly found above the main CO_2 reservoir before the well incident.

Table 11 - Measured concentrations of CH_4 and CO_2 in the overburden before remediation in 2007

Well	**Year of measurement**	**Sampling depth (m)**	**CH_4 (mol %)**	**CO_2 (mol %)**
Bcj-1	1996	893-911	15.1	79.8
Bcj-2	2002	658-672	44.4	51.3

To remediate the CO_2 leak, a new well Bc-9 was directionally drilled in 2006 (and completed with minor kicks and fluid loss) to reach the bottom of the collapsed well Bc-5 and a gel-forming material was injected to plug the leakage pathway in-situ (Figure 18). Well Bc-9 penetrates the upper section of the main CO_2 reservoir, and its liner casing is completely cemented and perforated in the interval of 1,131 to 1,133 m. The bottom of Bc-9 is believed to be 11m away from the bottom of the collapsed well Bc-5 (Figure 19).

Figure 18 - Position of remediation and monitoring wells of the collapsed well Bc-5

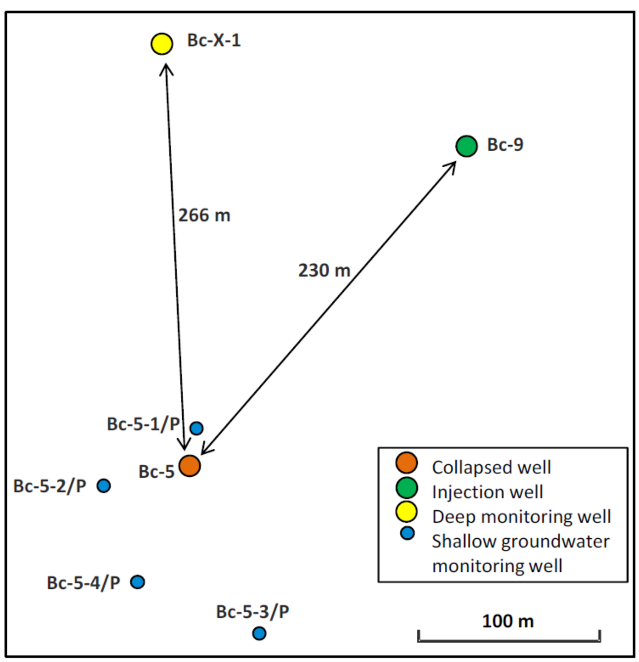
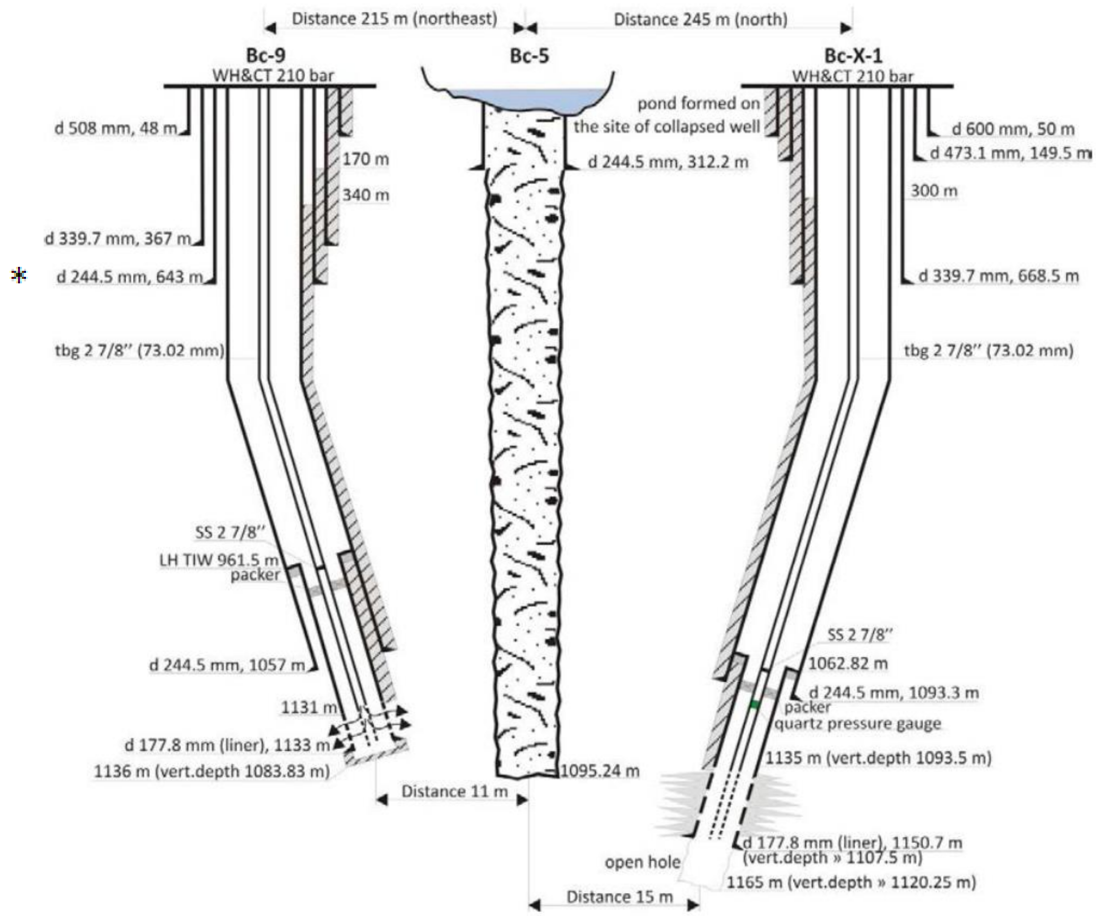


Figure 19 - ***Designs of injection well Bc-9, monitoring well Bc-X-1, and collapsed well Bc-5***



Another directional well Bc-X-1, which was drilled as part of the remediation activities in 1969 but not used, served as observation and back-up injection well. The bottom of Bc-X-1 is believed to be within a 15 m distance from the bottom of Bc-5 (Figure 19). *NOTE: There appears to be an error in the original publication of the 244.5 mm diameter casing set at 643 m and the production casing also shown to be 244.5 mm in diameter set at 1057m. The upper casing should read having a casing of 339.7 mm diameter set at 643 m in Well Bc-9.

The remediation performed by NIS was done in two phases: the preparatory phase and the main treatment. The preparatory phase included the injectivity test, acidizing job and flush treatment to clean the well with a volume of 150 m^3 of water injected during this phase.

The main treatment included the injection of 170 m^3 of environmentally-friendly chemicals in well Bc-9. The treatment was designed in such a way that it could be repeated if not successful the first time. Injection lasted one month and consisted of the following steps:

- *Injection of pure silicate solution to fill the collapsed zone of well Bc-5*
- *Injection of silicate solution containing polymer and urea that cause polymerization of silicates, coagulate and gel forming a solid void-filling material*
- *Injection of polymer-silicate solution containing urea and formaldehyde*
- *Alternating injection of polymer-silicate solution and cross-linking solution*
- *Injection of 2,000 m^3 of water to flush the chemicals off the bottom-hole*

A moderate increase of pressure and inflow of fluid observed in monitoring well Bc-X-1 from the early phase of operations, were the first signs that the damaged well Bc-5 and the bottom of the well Bc-X-1 were filled up with the chemicals that were injected through well Bc-9.

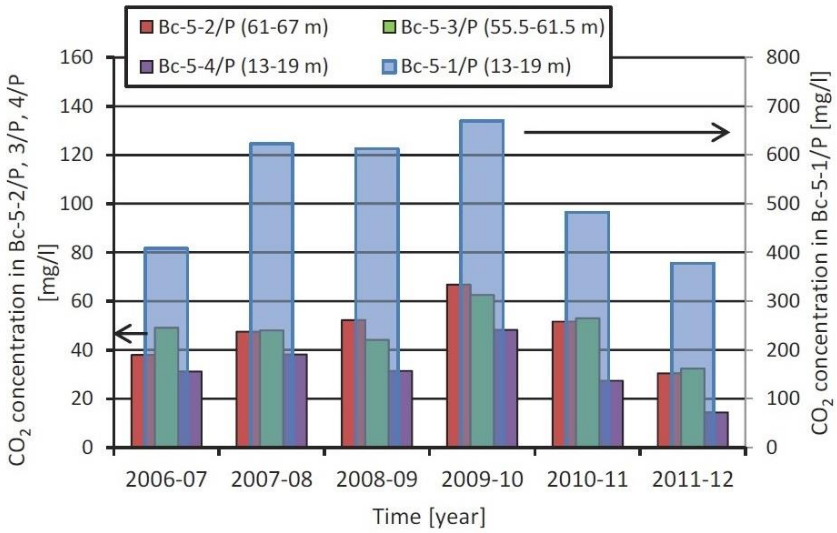
The long-term monitoring program included monitoring of ground water quality and formation pressures over the subsequent years.

<u>Monitoring the effects of remediation</u>

Groundwater monitoring was done for 6 years (2006-2012 - starting one year prior to start of remediation operations in 2007 to establish baseline data). Sampling frequency was one sample/month and the sampling parameters that were measured included CO_2, concentration, pH, carbonate and bicarbonate content, hardness, dry residue and potassium permanganate.

During the six years of monitoring, the measure concentrations of CO_2 in three wells did not exceed values of a few tens of mg/l, which are within the range of natural concentrations of CO_2 in shallow aquifers. Remarkable deviations were recorded in monitoring well Bc-5-1/P, which is closest to the collapsed well Bc-5, with the CO_2 concentrations in Bc-5-1/P being 4-5 times higher than that in Bc-5-4/P, although both wells monitor the shallow unconfined aquifer at the 13-19 m depth range. High concentrations in Bc-5-1/P are attributed to uncontrolled migration of CO_2 caused by the well blowout in 1968. CO_2 concentrations in all wells reached the maximum values in 2010, three years after the remediation. Since 2010, a steady decline in CO_2 concentrations is observed in all wells (Figure 20).

Figure 20 - ***Measured CO_2 concentrations in the groundwater at site Bc-5***



Measured formation pressures clearly indicate that the remediation measures performed in 2007 were effective. The decline in reservoir pressure, noticeable during the period 1968-2007, was practically stopped after the remediation. This implies that the unwanted migration of CO_2 from the main pool into the overlying aquifers via the collapsed well was significantly reduced, if not completely stopped, and that the remediation measures were successful.

8.2.1 Summary and Conclusions

Corrective measures need to be taken in the event of unwanted migration and leakage of CO_2 from an engineered geological storage site. The remediation performed at the Beĉej CO_2 field in Serbia to stop the leak caused by a well blowout in 1968 is, to the best of the authors' knowledge, the first known field-scale application of an in-situ remediation performed on a natural CO_2 reservoir, and is particularly relevant – a natural analogue for a large-scale engineered geological storage site. The Beĉej field case is an excellent case to study in the MiReCOL project, which has produced a handbook of corrective measures that can be considered in the event of significant irregularities and leakage from a CO_2 storage site.

8.3 CASE STUDY # 3: UTHMANIYAH CO_2 EOR AND CO_2 STORAGE PROJECT, SAUDI ARABIA

CO_2 at the injection site at the Uthmaniyah production unit, comes from the Hawiyah Natural Gas Liquids (NGL) Recovery Plant via a 85 km (52 miles) pipeline and is injected at a depth between 1,800 to 2,100 m (6,000 to 7,000 feet) at a rate of around 0.8 million tonnes per year (40 million standard cubic feet per day – (MMscf/d)). Saudi Arabia's light crude oils are particularly suited for CO_2 EOR since CO_2 is an excellent solvent especially for light crudes and if the reservoir pressure is higher than the miscibility pressure of CO_2 with the crude, it can significantly enhance oil recovery. The Uthmaniyah is a large oil field and a mature and water flooded part of the carbonate reservoir was selected for the CO_2 injection, with a considerable amount of reservoir and production historical data available.

Simulation studies

The reservoir selected for CO_2 injection is a Jurassic age carbonate reservoir and the area selected is in a down flank, small flooded area of the field and has been on peripheral water injection for over 50 years. Approximately 40 MMscf/d (1.13 Mm^3/d) of relatively pure CO_2 was available from the Hawiyah NGL plant that could be captured. This became the basis for the simulation sensitivity study and pilot design. The main objectives of the simulation study were:

- *Carry out screening and mechanistic studies and find areas suitable for a CO_2 injection pilot*
- *Assess amount of CO_2 sequestered over the pilot testing period*
- *Assess incremental oil recoveries associated with different modes of CO_2 injection*
- *Optimize the pilot design within the reservoir and operational constraints*

A dual porosity dual permeability (DPDP) black-oil dynamic simulation model converted to its equivalent DPDP compositional model was used for the simulations. An equation of state (EOS) was developed for compositional simulation from PVT data. The number of layers was increased from 17 to 37 (medium resolution) and finally to 289 (high resolution) to improve the DPDP model simulations. Potential areas for a CO_2 flood pilot test were selected from a streamline pattern of the current water flood for the entire field.

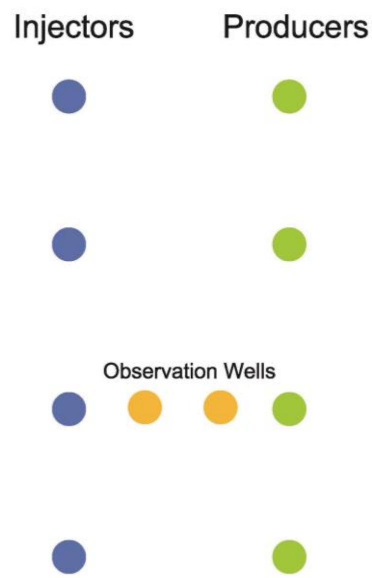
A large number of simulation runs were made to understand the factors that influenced the amount of CO_2 that could be stored, magnitude of incremental oil recovery, and the timing of the incremental recovery. Vertical versus horizontal well orientation and various completion scenarios were also examined. Vertical wells were found to be more efficient and operating in a WAG mode was selected for optimal sequestration and oil recovery.

Pilot Design

The pilot test is designed to obtain definitive results within 1 to 3 years and to clearly demonstrate the amount of CO_2 sequestered and miscible CO_2 oil recovered. There are four injectors with four producers placed updip about 2,000 feet (~ 600 meters) from the injectors, in a line drive injection pattern, because water injection in the field has been peripheral. CO_2 will be injected at a maximum rate of 40 MMscf/d

(1.13 Mm^3/d) into two of the injectors, with water injection into the other two wells (WAG injection strategy with alternate injection every month). In addition, two observation wells are located between the second injector and its corresponding producer (Figure 21). One of the observation wells is completed open hole across the reservoir, while the other observation well is completed with a non-metallic casing opposite the reservoir. The wells are logged frequently to monitor CO_2 movement and gravity segregation between an injector and a producer.

Figure 21 - *Arrangement of injectors, producers and observation wells in the CO_2 flood pilot (Kokal et al, 2016)*



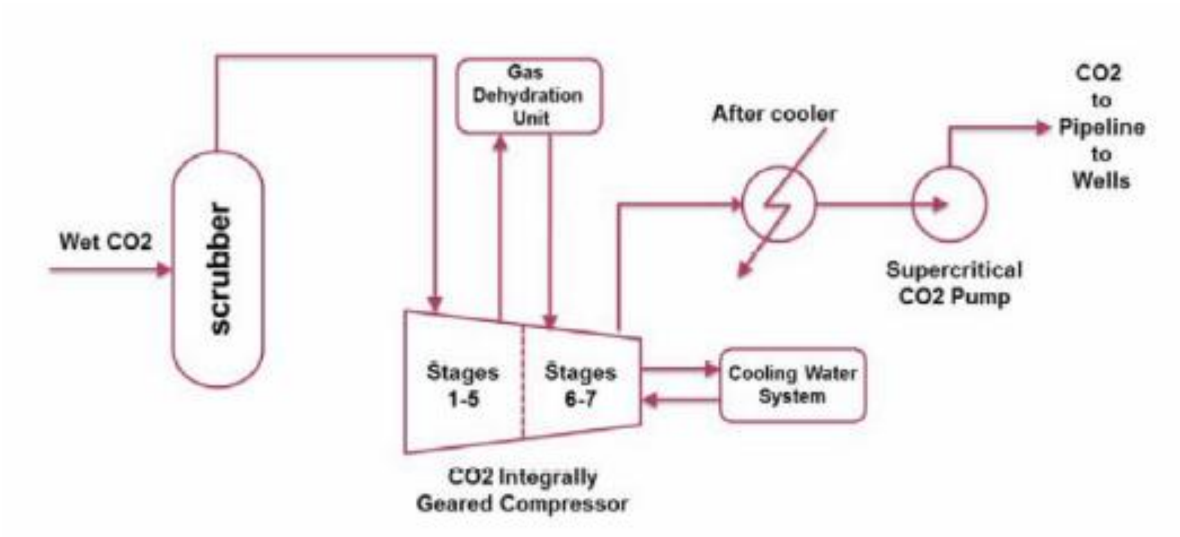
This pilot is designed to address the following risks:

- *The CO_2 plume movement within the reservoir and its containment*
- *The amount of CO_2 that will be stored in the reservoir*
- *The extent to which gravity segregation will occur in a line-drive flood and the reservoir factors that affect it*
- *The volume of oil that can be contacted, displaced, and produced*
- *Well injectivity during WAG to CO_2 and water*

<u>CO_2 Capture Plant</u>

About 40 MMscf/d (1.13 Mm^3/d) of relatively pure CO_2 is available from the Hawiyah NGL plant located about 85 km from the pilot site, and prior to the project, the saturated and wet CO_2 was being vented to the atmosphere. A front-end engineering design (FEED) was conducted to capture, compress and dehydrate the CO_2 from the plant, and transport the supercritical CO_2 via a new pipeline for injection at the pilot location (Figure 22). The wet CO_2 is compressed by a 7-stage integrally geared compressor. After the 5th stage, the wet CO_2 is routed to a gas dehydration unit for removal of water using tri-ethanol glycol (TEG) with the 6th and 7th stages only handle dry CO_2. The dry CO_2 from the compressor is then compressed to a delivery pressure of 3,500 psia (~ 24 MPascal) using a dense phase pump. The supercritical CO_2 is then transported through a new 86-km pipeline to the injection wells at the pilot site.

Figure 22 - CO_2 capture plant schematic (Kokal et al, 2016)



Produced Fluids Handling

The produced fluids from the four new producers are routed to a gas oil separation plant (GOSP) through a common trunk line. To keep the CO_2 produced fluids separate from the wider field produced crude oil and water, a standalone high pressure production trap (HPPT) was designed and installed specifically for the project.

The pipeline from the wellhead, the trunk line and the new produced handling facility were specially designed and internally coated to protect against the anticipated corrosion from wet produced CO_2.

Injectors and Producers

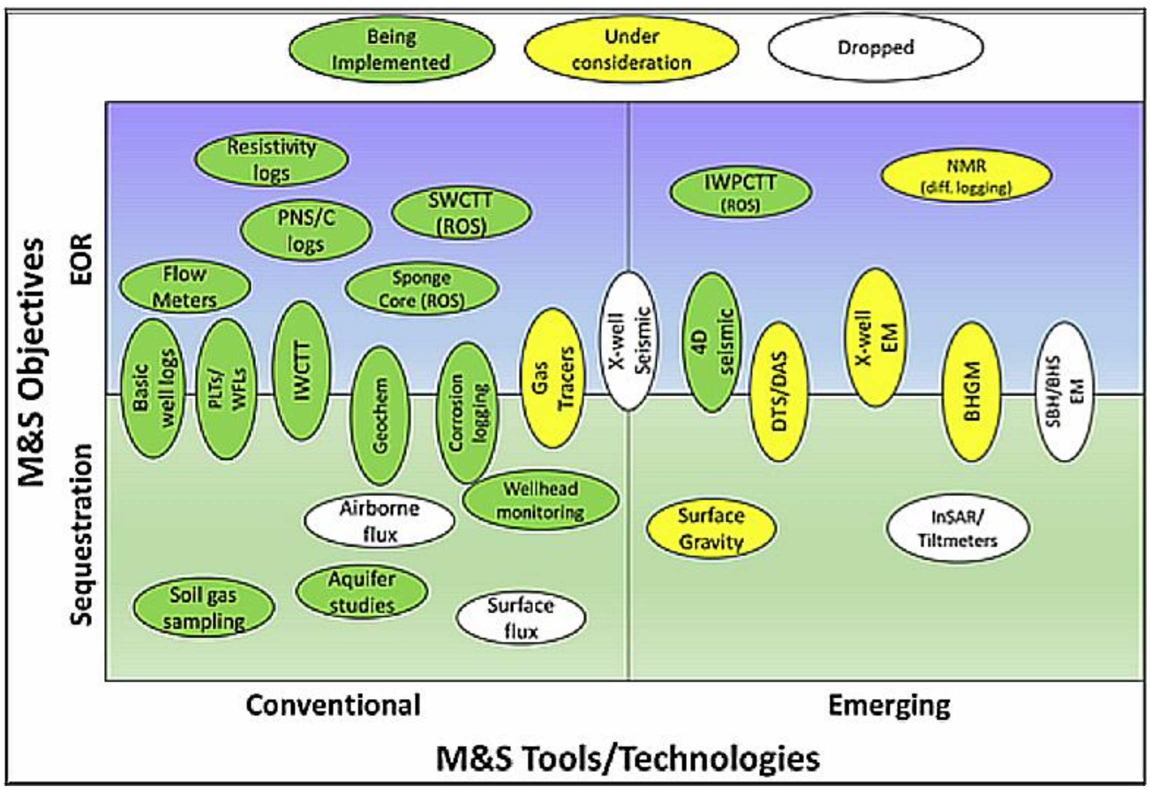
The four injectors and four producers were designed as fit-for-purpose wells. The injectors were carbon steel and cased hole with perforations at the bottom of the reservoir. Carbon steel was selected since the dry CO_2 is not corrosive and the water is treated with a corrosion inhibitor. Also, the interaction time between dry CO_2 and water is very short during the WAG switching operation. The producers were also carbon steel but epoxy coated for corrosion protection and perforated at the top of the reservoir. Each of the injectors was installed with a Coriolis meter and a multiphase flowmeter (MPFM) at the wellhead. This enabled the amount of CO_2 and water injected and the amount of oil, water and gas produced at the wells to be recorded.

Monitoring and Surveillance

A robust monitoring and surveillance program was developed and deployed. The primary objectives of the M&S program are to: obtain requisite data to evaluate the pilot project; measure the amount of CO_2 sequestered, monitor pre- and post-CO_2 remaining oil saturations, understand the recovery mechanisms, track the CO_2 plume, monitor inadvertent out-of-zone CO_2 leakage, well integrity problems, and understand operational challenges.

Some activities are targeted toward EOR based objectives and some toward sequestration objectives and Figure 23 shows the original M&S plan developed for the project.

Figure 23 - Monitoring and surveillance plan for the demonstration plan (Kokal et al, 2016)



Base logs for reservoir characterization

Base logs for pre-injection reservoir characterization were acquired in all the wells. Triple combo (resistivity, density, neutron) logs, image logs formation pressure data and cement bond logs were acquired in all the wells; formation samples, nuclear magnetic resonance (NMR), and dielectric logs were acquired in all the producers and observation wells; and full wave sonic, vertical seismic profile (VSP) and cored data were acquired in a few selected wells. The key drivers in data acquisition were "value of information" (VOI) and optimization.

<u>*Routine M&S tools and tests*</u>

Some of these tools and technologies used for routine M&S are described below;

- *Pulsed neutron spectroscopy and capture (PNS/C) tool: This is logged in time-lapse mode for monitoring changes and redistribution of remaining oil saturation (ROS) in the reservoir around the producer and observation wells. Because of its high vertical resolution, the data also gives some insight into the vertical sweep efficiency.*

- *Production logging tool (PLT) and Water flow log (WFL): These are run periodically in producers and injectors to determine production and injection profile changes with time in each well. The PLT also provides down-hole production rates and contribution from the different flow units while the WFL can provide early warning about potential injectivity problems.*

- *Sponge cores: Sponge cores were obtained in the observation wells (drilled at different times) to determine the ROS across the different zones in the reservoir before infill water injection and shortly prior to the start of CO_2 injection. Special sidewall cores will be taken through one of the wells after CO_2 injection phase to determine (ASor) attributable to CO_2 injection.*

- *Corrosion logs: These are being acquired periodically to determine the integrity of each well (especially the injectors that may experience elevated pressures and CO_2-water interaction that may lead to corrosion). The plan is to deploy tools that can estimate casing wear or thickness reduction through multiple casings. Timely diagnosis of any casing wear or thickness reduction will prevent unwanted out-of-zone leakage.*

- *Soil gas sampling: In order to demonstrate that there is no CO_2 leakage to the surface, periodic soil gas sampling and analyses are being conducted. Parameters being monitored are CO_2, CH4, N_2, O_2, Ar, Rn, He, and isotopes of carbon. Results will be compared with baseline data measurements and changes during and post CO_2 injection.*

- *Aquifer studies: As part of sequestration objectives, shallow and deep aquifers are being monitored to detect any contamination. Samples are being collected and analyzed for volatile organic compounds (VOC), dissolved organic compounds (DOC), BTEX (benzene, toluene, ethylbenzene, and xylenes), phenols, Na, Cl, Ca, Fe, Mn, pH, alkalinity, and isotopes of carbon, oxygen, and hydrogen.*

- *Wellhead monitoring: Annulus pressures (especially in the injectors) are being monitored periodically, to determine any potential seepage into the annulus (and sustained casing pressure).*

- *Geochemical sampling and analyses: Periodic geochemical sampling and analyses of water samples from the producers are being collected to collect data to calibrate the reactive transport model to estimate the amount of CO_2 being sequestered.*

<u>*Emerging M&S tools and methods*</u>

Most of the tools mentioned above provide near wellbore information. In order to understand reservoir properties and changes between wells (vertically, aerially, or in 3Dspace) some of the tools discussed below need to be deployed. Some are new (emerging) while others have been reconfigured to suit the project objectives and are briefly described below:

- *4D Seismic: Time Lapse 3D Seismic (4D Seismic) technology has been applied to measure reservoir property changes resulting from oil and gas operations and in some CCUS projects to track CO_2 plume migration. Feasibility studies showed this technology can be applied to this project due to the significant density contrast between the CO_2 and the reservoir fluid, and therefore a continuous seismic monitoring program was designed for mapping the CO_2 plume areal extent. The design comprised of surface vibrators in combination with multi-component sensors (over a 1000 receivers) deployed below the water table at a depth of about 70 m, and is one of the largest permanent monitoring installations in the world. It has a unique continuous acquisition program where surveys are acquired continually (one/month) for the life of the project, unlike conventional 4D seismic where snapshots or surveys are acquired every 6 to 12 months or even longer periods.*

- *Interwell chemical tracer test (IWCTT): Four distinct environmentally friendly tracers were injected into each of the four injectors to provide injector-producer connectivity, flow-path data, and breakthrough times that may help in modifying WAG sequence and timing and insights into communication between injector-producer pairs.*

- *Interwell gas tracer test (IWGTT): Due to the potential mobility and relative permeability differences between water and gas injection phases, special gas tracers are planned to be injected with CO_2 into each of the injectors to determine CO_2 flow-paths and connectivity with producer pairs and to confirm CO_2 break-through times that may be different than those measured during infill water injection phase. In addition, the data will help to identify well leaks in case of inadvertent CO_2 leakage to the surface.*

- *Single well chemical tracer test (SWCTT): One of the key indicators of efficacy of the pilot test for EOR purposes is a good understanding of the ROS in the reservoir prior to and after CO_2 injection. SWCTT provides such data at about a 30 foot radius around the well and was conducted in a specific well prior to CO_2 injection. A post-CO_2 injection SWCTT will be run at the end of the project and the changes in ROS (ASor) will be a good input into reservoir modelling for estimation of swept volume.*

- *Surface gravity measurement: Time lapse 4D gravity measurement has been successfully deployed in a few miscible gas projects (Prudhoe Bay) and CCUS projects (Sleipner). Given the huge contrast between CO_2 density and the fluid density in the shallow aquifers, resulting in gravity signals in the 10s to 100s of microGal, surface gravity measurements would be beneficial for monitoring inadvertent out-of-zone leakage in the shallow aquifers.*

- *Interwell partitioning chemical tracer test (IWPCTT) for ROS: A new set of novel partitioning interwell tracers was deployed to measure inter-well ROS between one of the injector-producer pairs.*

- *Fiber optic sensors: Distributed temperature sensing (DTS) is being deployed for temperature profiling behind casing. A new generation of fiber-optic sensors such as distributed acoustic sensing (DAS), distributed chemical sensing (DCS), and distributed acoustic sensing are commercially available or are being developed. Feasibility studies are ongoing to deploy a novel fiber optic sensing* *rod that can be run on wireline or coiled tubing and perform multiple sensing jobs such as DTS, DPS and DAS concurrently on a single run.*

- *Electromagnetic (EM) measurement: X-well EM measurement has been deployed in a few CCUS projects to monitor CO_2 plume evolution in 2D between pairs and by Saudi Aramco to see oil distribution between oil pairs. In addition surface to borehole EM (SBEM) and borehole to surface (BSEM) hold promise for monitoring CO_2 migration in shallow aquifers.*

- *Interferometric Synthetic Aperture Radar (InSar) and Tiltmeters: Insar in combination with high-resolution GPS and tiltmeters provide a means of measuring surface deformation (uplift or subsidence) over vast areas. InSar was successfully applied as a diagnostic tool to measure CO_2 migration in the In-Salah CO_2 storage project. A feasibility study showed no potential for applying this technique here, since there was no significant change in the reservoir pressure before and after CO_2 injection.*

8.3.1 Summary and conclusions

- *Saudi Arabia has embarked on its first carbon capture, utilization, and storage project through a CO_2 EOR demonstration project. This project is being pursued primarily to demonstrate the feasibility of sequestering CO_2 through EOR, and using it as grounds to test new M&S technologies*

- *An integrated multidisciplinary, multi-departmental and multi-organizational approach is necessary to design and execute such a project.*

- *The objectives of the project should be clear from the beginning, with the primary objectives of this project being to sequester CO_2 and enhance oil recovery.*

- *The design and development plans should take into consideration appropriate uncertainties in the project risk register*

- *Due diligence must be given to generate all relevant experimental data that are subsequently used in simulations and project design. These must be performed at reservoir conditions; otherwise they may have limited value or may be detrimental to the project.*

- *The location of the pilot should not be based on a singular design and many options should be considered; it should be based on reservoir simulation sensitivity studies.*

- *A robust and comprehensive monitoring and surveillance (M&S) program is necessary to generate, analyze and evaluate the data and performance of the project.*

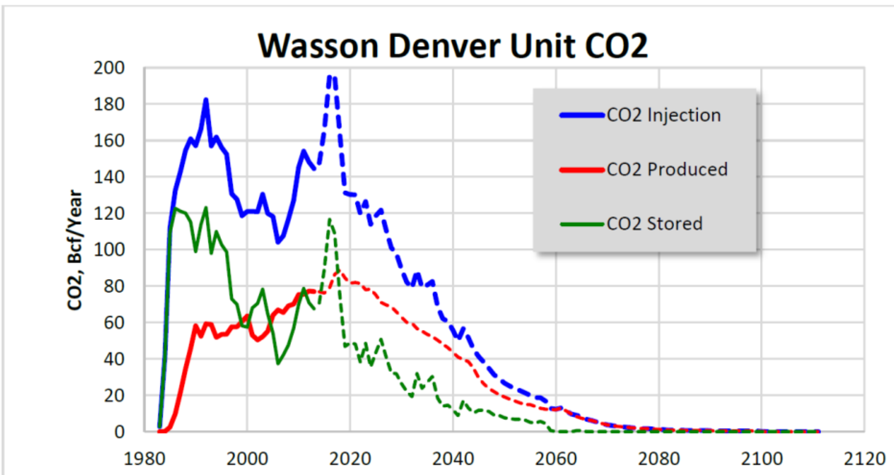
8.4 CASE STUDY # 4: OXY DENVER UNIT, WASSON FIELD, TX (OXY DENVER UNIT CO_2 SUBPART RR - MONITORING, REPORTING AND VERIFICATION (MRV) PLAN, 2015)

<u>Background</u>

Occidental Petroleum Ltd. (OPL) operates the Denver Unit in the Permian Basin for the primary purpose of enhanced oil recovery using CO_2 flooding. OPL also intends to inject CO_2 (fresh CO_2 purchases plus recovered CO_2 from the Denver Unit CO_2 Recovery Plant - DUCRP) with a subsidiary purpose of storing CO_2 for a specified period 2016 through 2026.

Figure 24 shows the actual CO_2 injection, production, and stored volumes in the Denver Unit for the period 1983 through 2013 (solid line) and the forecast for 2014 through 2120 (dotted line). Oxy adjusts its purchase of fresh CO_2 to maintain reservoir pressure and increase oil recovery by extending or expanding the CO_2 flood. Oxy has injected 4,035 Bscf of CO_2 (212.8 million metric tons – Mt) into the Denver Unit through end of 2013, of which 1,593 Bscf (84.0 Mt) was produced and 2,442 Bscf (128.8 Mt) was stored. Oxy forecasts that the total volume of CO_2 injected will be ~ 25% of the theoretical storage capacity of the Denver Unit.

Figure 24 - Denver Unit Historic and Forecast CO_2 Injection, Production, and Storage 1980-2120 (Oxy MRV, 2015)



<u>*Geology of the Wasson Field*</u>

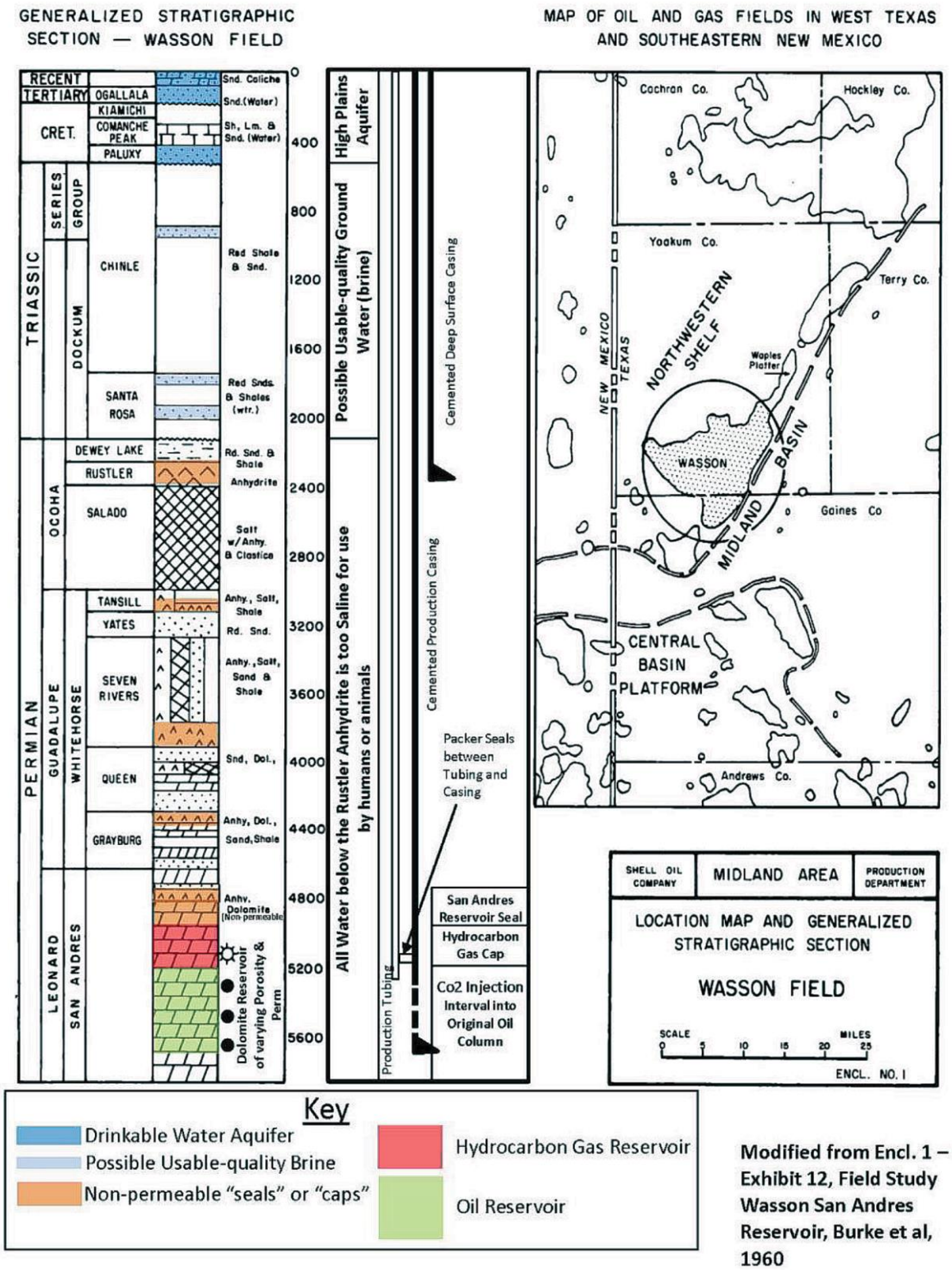
The Wasson Field produces oil from the San Andres formation, a layer of permeable dolomites deposited in a shallow marine environment during the Permian period, some 250 to 300 million years ago (Permian Basin).

The Wasson Field is located in southwestern Yoakum and northwestern Gaines Counties of West Texas, approximately 100 miles north of Midland, TX and ~ 5 miles east of the New Mexico state line. Discovered in 1936, the Wasson Field with nearly 4,000 million barrels (MMB) of Original Oil in Place (OOIP) is one of the largest oil fields in North America. Originally flat, there are now variations in elevation within the San Andres formation across the Permian Basin. The relative high spots, such as the Wasson Field, have become places where oil and gas have accumulated over the ensuing millions of years.

As shown in Figure 25, the San Andres formation now lies beneath some 5,000 feet of overlying sediments and is capped with nearly 400 feet of impermeable dolomite, referred to as the Upper San

Andres. This seal has kept oil and gas trapped in the lower San Andres for millions of years indicating that it is a seal of the highest integrity. Other zones also serve as seals and the sealing properties can be confirmed with logs, all indicating a lack of permeability.

Figure 25 - Stratigraphic Section at Wasson (Oxy-MRV, 2015)



Between the surface and about 2,000 feet (610 m) in depth are intervals of underground sources of drinking water (USDW) and include the Ogallala and Paluxy aquifers. In addition, there are other potentially useful brine intervals. The Texas Railroad Commission (TRCC) which regulates the Class II program in Texas requires all wells drilled through these intervals confine fluids to the strata in which they are encountered or injected and wells should meet the casing and cementing requirements to ensure confinement (See Section 7.1).

There are no known faults or fractures affecting the Denver Unit that provide an upward pathway for fluid flow. The absence of faults or fractures is confirmed in several ways. First, the presence of oil, especially oil that has a gas cap, is indicative of a good quality natural seal. Second, Oxy has conducted seismic surveys that characterize the formations and as input into the reservoir models used to design injection patterns. These surveys show the presence of faulting well below the San Andres but none that penetrate the flooding interval. Finally, the operating history of the Denver Unit confirms that there are no faults or fractures penetrating the flood zone, since the injection of fluids, both water and CO_2 have been successfully injected since the 1960s and have shown no interaction with existing or new faults or fractures.

Operational History of the Denver Unit

The Denver Unit is a subdivision of the Wasson Field and was established in the 1960s to implement water flooding. CO_2 flooding of the Unit began in 1983 and has expanded since that time. The experience of operating and refining the Denver Unit CO_2 floods over three decades has created a strong understanding of the reservoir and its capacity to store CO_2.

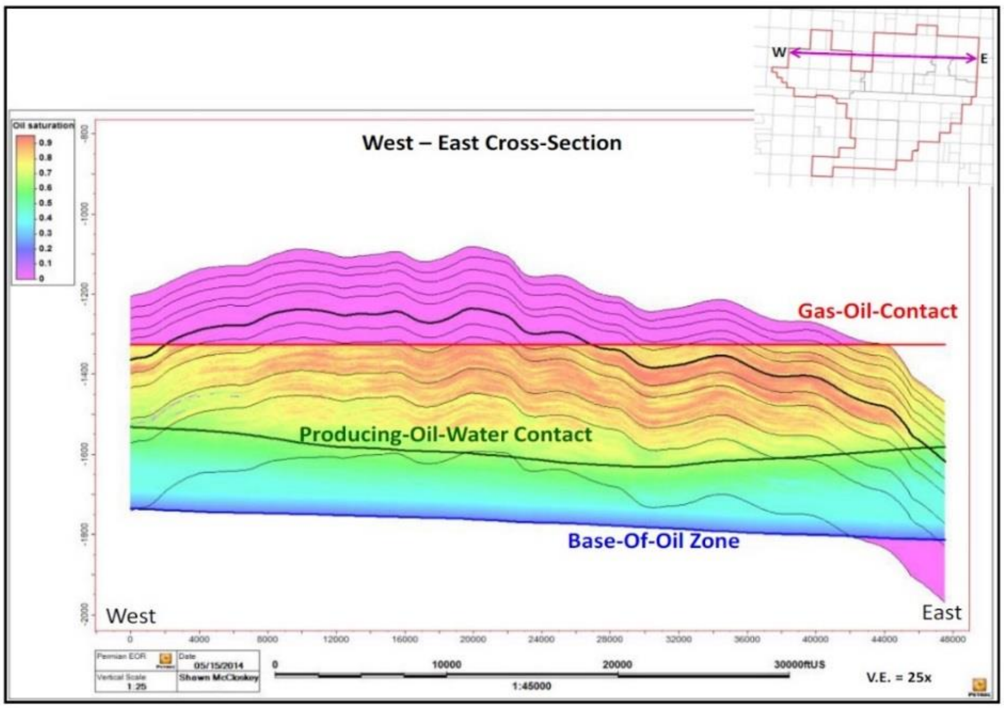
Oil production began in the Denver Unit in 1938 and peaked in the mid-1940s. The operator began pressure maintenance with secondary recovery (water flooding) in 1965 with CO_2 EOR beginning in 1983. Primary recovery resulted in the production of 17.2% of the original oil in place (OOIP), secondary recovery 30.1% of the OOIP with an additional expected recovery of 19.5% through CO_2 EOR. Total oil recovery is expected to reach 66.8% of the OOIP. The total OOIP in the Denver Unit is estimated at 2 billion barrels with CO_2 EOR estimated to recover 0.39 billion barrels (NETL/ARI, 2011)

Geology of the Denver Unit within the Wasson Field

As indicated earlier, the upper portion of the San Andres is comprised of impermeable anhydrite and dolomite sections that serve as a seal and, in effect, form the hard ceilings of an upside bowl or dome. Below this seal the formation consists of permeable dolomites containing oil and gas. The Denver Unit is located at the highest elevation of the San Andres formation within the Wasson Field, forming the top of the dome. The rest of the Wasson Field slopes downward from this area, effectively forming the sides of the dome. The elevated area formed a natural trap for oil and gas that migrated from below over millions of years. Over time, fluids, including CO_2, in the Wasson would rise vertically until meeting the ceiling of the dome and would then follow it to the highest elevation in the Denver Unit. As such, the fluids injected into the Denver Unit would stay in the reservoir rather than move to adjacent areas.

Buoyancy dominates where oil and gas are found in the reservoir. Figure 26 shows the saturation levels in the oil-bearing layers of the Wasson Field. Above the gas-oil interface is the volume known as the "gas cap", and the presence of a gas cap is evidence of the effectiveness of the seal formed by the upper San Andres. Gas is buoyant and highly mobile and if it could escape the Wasson Field naturally, through faults or fractures, it would have done so over the millennia.

Figure 26 - Wasson Field Cross-Section Showing Saturation (Oxy-MRV, 2015)

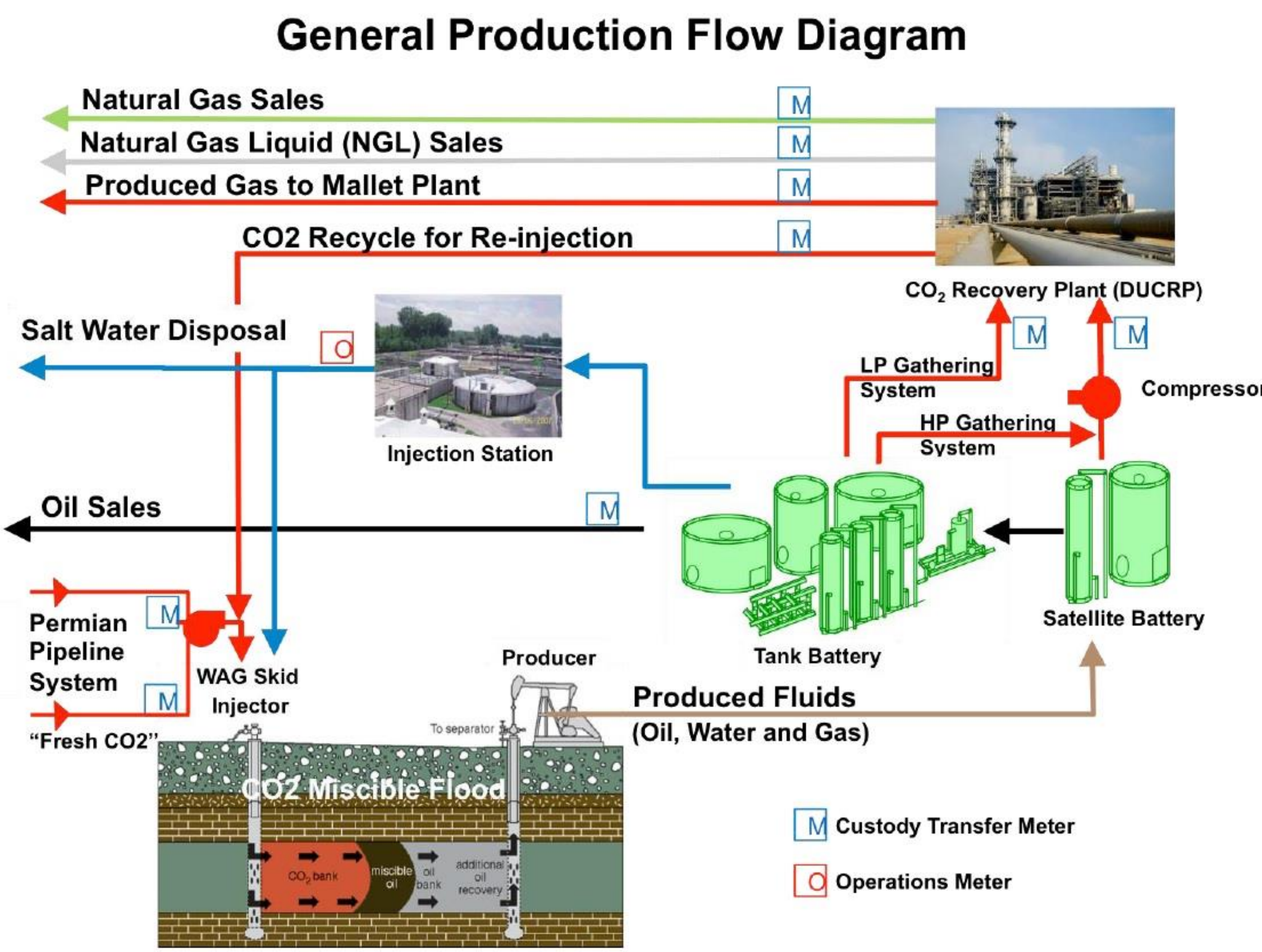


Below the level of the producing oil-water contact, wells produce a combination of oil and water. The uppermost region this area is called the transition zone (TZ) and below that is the residual oil zone (ROZ). The ROZ was water flooded by nature millions of years ago, leaving a residual oil saturation. This is approximately the same residual oil saturation remaining after water flooding in the water-swept areas of the main oil pay zone, and is also a target for CO_2 flooding.

When CO_2 is injected into an oil reservoir, it is pushed from injection wells to production wells by the high pressure of the injected CO_2. Once the CO_2 flood is complete and injection ceases, the remaining mobile CO_2 will rise slowly upward, driven by buoyancy forces. If the amount of CO_2 injected into the reservoir exceeds the secure storage capacity of the pore space, excess CO_2 could theoretically "spill" from the reservoir and migrate to other reservoirs in the Northwest Shelf. The risk is very low in the Denver Unit, because there is more than enough pore space to retain the CO_2 (based on Oxy's calculations). Oxy forecasts that at the end of EOR operations stored CO_2 will fill approximately 25% of calculated storage capacity.

Figure 27 shows a simplified flow diagram of the EOR project facilities and injection process. CO_2 is delivered to the Wasson Field via the Permian pipeline delivery and specified amounts are drawn based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator. Once CO_2 enters the Denver Unit there are four main processes involved in EOR operations as shown in Figure 39 and described below:

Figure 27 - Denver Unit Facilities General Production Flow Diagram (Oxy-MRV, 2015)



<u>*CO_2 Distribution and Injection*</u>

Currently, Oxy has 16 injection manifolds and approximately 600 injection wells in the Denver Unit. The manifolds are a complex of pipes that have no valves and do not exercise any control function. Approximately 400 MMscf of CO_2 is injected each day made up of 47% fresh water and 53% recycled from the DUCRP. The ratio of fresh CO_2 to recycled CO_2 is expected to change with time and eventually the purchase of fresh water will taper off and end in 2059.

Each injection well has an individual WAG skid located near the wellhead (typically 150-200 feet away) and the WAG skids are remotely operated and can inject CO_2 or water at various rates and injection pressures as specified in the injection plans. At any given time about half the injectors are injecting CO_2 and half are injecting water, and the length of injection time for each fluid is continually optimized to maximize oil recovery and minimize CO_2 utilization in each injection pattern. Data from the WAG skid control systems (includes flow meter data on fluid injection rates and pressures), visual inspection and regulatory procedures as per 40 CFR §98.230-238 (Subpart W) will be gathered to complete the mass balance equations necessary to determine annual and cumulative volumes of stored CO_2.

Wells in the Denver Unit

As of August 2014, there are ~ 1,734 active wells in the Denver Unit, with about 2/3rd production wells and 1/3rd injection wells. Table 12 gives the well counts for wells within the Denver Unit, while Table 13 gives the well counts for wells that penetrate the Denver Unit but are completed in formations other than San Andres.

Table 12 - Denver Unit Wells

Age/Completion of Well	**Active**	**Shut-in**	**Temporarily Abandoned**	**Plugged and Abandoned**
Drilled after 1996	619	3	23	3
Drilled 1961-1996 with production casing cemented to surface	388	2	58	49
Drilled between 1972-1975 using lightweight casing	247	1	16	32
Drilled before 1960	480	2	47	212
Total	**1734**	**8**	**144**	**296**

Table 13 - Non-Denver Unit Wells

	Oxy	**Oxy**	**Oxy**	**Non-Oxy**	**Non_Oxy**
Age/Completion of Well	**Shut-in**	**Temporarily Abandoned**	**Plugged and Abandoned**	**Active**	**Inactive**
Drilled after 1996	2	16	1	181	10
Drilled 1961-1996 with production casing cemented to surface	4	69	94	214	89
Drilled between 1972-1975 using lightweight casing	0	0	0	0	1
Drilled before 1960	0	28	29	103	44
Total	**6**	**113**	**124**	**498**	**144**

Tables 12 and 13 categorize the wells in groups that relate to age and completion methods. The wells drilled after 1996 were completed using state-of-the-art standards (that is use of regular weight casing cemented to surface). In 1996, Shell, which then operated the Denver Unit, as well as the major Clearfolk leases that lie under the Denver Unit, implemented a policy that wells be cemented to surface following these standards and Oxy has continued this practice. The majority of wells drilled during 1961-1996 have production casing cemented to surface, and a subset of this group uses lightweight casing. The last group covers older wellbores drilled before 1960 and Oxy considers these categories when planning well maintenance activities. Further, Oxy keeps well workover crews on site in the Permian to maintain all active wells and to respond to any wellbore issues that arise.

All wells, both injectors and producers, are regulated by TRCC. TRCC rules govern well siting, construction, operation, and maintenance and closure for all wells in oilfields (See Section 7.1). Briefly current rules require:

- *That fluids be constrained in the strata in which they are encountered*
- *That activities governed by the rule cannot result in the pollution of subsurface or surface water*
- *That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters*
- *That the operator files a completion report for each well including basic electric logs ((e.g., a density, sonic or resistivity (except dip meter) log run over the entire wellbore)*
- *That all wells be equipped with a Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected*
- *And that all well plugging follows procedures that require advanced approval from the Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.*

Under TRCC's program, all Class II wells used for fluid injection must comply with additional requirements to the Area of Review (AoR), casing design, special equipment for well monitoring, mechanical integrity testing (MIT) using a pressure test, and monitoring/reporting.

<u>*AoR Review*</u>

According to EPA, the AoR refers to "the area around a deep injection well that must be checked for artificial penetrations, such as other wells, that penetrate the injection or confining zone, and repair all wells that are improperly completed or plugged. The AoR is either a circle or radius of at least ¼ mile

(402 m) around the well or an area determined by calculating the zone of endangering influence, where pressure due to injection may cause the migration of injected or formation fluid into a USDW." These requirements thus require that Oxy locate and evaluate all wells within the AoR and that the AoR requirements are satisfied, prior to injection of CO_2, water or other fluids within the Denver Unit.

Mechanical Integrity Testing (MIT)

TRCC's MIT requirements are designed to ensure that there is no significant leakage within the injection tubing, casing, or packer, as well as no leakage outside the casing (due to a bad cement job or due to channeling). All active injection wells undergo MIT testing (referred to as "H-5" testing) at the following intervals:

- *Before injection operations begin*
- *Every 5 years unless permitted otherwise*
- *After any workover that disturbs the seal between the tubing, packer, and casing*
- *After any repair work on the casing*
- *When a request is made to suspend or reactivate the injection or disposal permit.*

The current requirements for conducting MIT are:

For wells with tubing - pressure test the tubing-packer-casing to a pressure between 200 and 500 psi (1.4 – 3.5 MPa). Test pressure must stabilize within 10% of the required test pressure and remain stabilized for 30 minutes (60 minutes if testing with a gas-filled annulus). Maintain a minimum of 200 psi (1.4 Mpa) pressure differential between the test pressure and tubing pressure.

For wells without tubing - pressure test immediately above injection perforations against a temporary plug, wireline plug, or tubing with packer. Indicate the type and depth of the plug and must be tested to a maximum permitted injection pressure that is not limited to 500 psi (3.5 MPa).

If a well fails a MIT, the operator must immediately shut in the well, provide a notice to TRCC within 24 hours, file a Form H-5 within 30 days and make repairs or plug the well within 60 days. Casing leaks must be successfully repaired and the well re-tested, or plugged if required. In such cases, a Form W-3A must be filed with TRCC. Any well that fails an MIT cannot be returned to active service until it passes a new MIT.

TRCC requires similar testing at injection wells that are more than 25 years old and have been idle for more than one year (referred to as H-15 testing). For these wells, MIT is required every five years either with an annual fluid level test or a hydraulic pressure test with a plug immediately above the perforations. In the event of a test failure at these idle wells, the operator must repair or plug the well within 30 days (not 60 days allowed for an active well). Again, casing leaks must be successfully repaired and the well re-tested or plugged (after submitting a Form W-3A).

Produced Fluids Handling

Gathering lines bring the produced fluids from each production well (Oxy has 1100 production wells) to one of 32 satellite batteries with gas-liquid separators and well test equipment to measure production rates of oil, water and gas from individual production wells. Most wells are tested every two months.

After separation, the gas phase, which is ~ 80-85% CO_2 and 2,000 – 5,000 ppm H_2S is transported by pipeline to DUCRP for processing. The liquid phase (mixture of oil and water) is sent to centralized tank batteries for gravity separation of oil from water. The separated oil is metered through the Lease Automatic Custody Transfer (LACT) unit at each centralized tank battery and sold. The dissolved CO_2 content in the oil averages 0.13% by volume.

The water is removed from the bottom of the tanks and sent to a water treatment facility, and after treatment either re-injected at the WAG skids or injected into permitted disposal wells.

Any gas that is released from the liquid phase is collected by a Vapor Recovery Unit that compresses the gas and sends it to DUCRP for processing.

Wasson oil is slightly sour, containing small amounts of H_2S, which is highly toxic. There are approximately 90 workers on-site at the Denver Unit at any given time, and all field personnel are required to wear H_2S monitors at all times.

Produced Gas Handling

Produced gas is gathered from the satellite batteries and sent to centralized compressor stations and then to DUCRP in a high pressure gathering system.

Once gas enters DUCRP, it undergoes compression and dehydration. Produced gas is first treated in a Sulferox unit to convert H_2S into elemental sulfur which is sold and trucked from the facility.

Other processes separate NG and NGLs into saleable products. At the end of these processes, there is a CO_2 rich stream, a portion of which is recycled and again re-injected.

Water Treatment and Injection

Produced water is gathered through a pipeline system and moved to water treatment stations. After treatment, pressurized water is distributed to the WAG skids for re-injection or to water disposal wells for injection into deep permeable formations.

Fluid Containment Strategies

TRRC requires that injection pressures be limited to prevent contamination of other hydrocarbon resources or pollution of subsurface or surface waters. In addition, EOR projects are designed by Oxy to ensure that mobilized oil, gas, and CO_2 do not migrate into adjoining properties that are owned by competing operators, who could then produce the fluids liberated by Oxy's EOR efforts. In the Denver Unit, Oxy uses two methods to contain fluids within the Unit: reservoir pressure management and the careful placement and operation of wells along boundaries of other units.

Reservoir pressure in the unit is managed by maintaining an injection to withdrawal ratio (IWR) of approximately 1.0. The volumes are measured under reservoir conditions for all fluids and by keeping the IWR close to 1.0, reservoir pressure is held constant. To maintain the IWR, Oxy monitors fluid injection to ensure that reservoir pressure does not increase to a level that would fracture the reservoir seal or otherwise damage the oilfield. Similar practices are used for other units operated by Oxy within the Wasson Field. Most, if not all other Wasson Units, inject at pressures a little higher than Denver Unit and all maintain an IWR of at least one. Additionally, higher pressures in the surrounding areas assure that Denver Unit fluids stay within the Unit.

Oxy also prevents injected fluids migrating out of the injection interval by keeping injection pressure below the fracture pressure which is measured using step-rate tests.

The second way Oxy contains fluids within the Denver Unit is to drill wells along the lease lines as per lease agreements with the neighboring CO_2 units which provide for offsetting injectors or offsetting producers along the lease line that balance one another. For example, an injector on one side is balanced by an injector on the other side in such a way that a no-flow boundary is maintained at the Unit boundary. This restricts the flow of injected CO_2 or mobilized oil from one unit to the other. A similar dynamic is maintained for paired producers.

Reservoir Modeling

Oxy uses simulators to model the behavior of fluids in the reservoir. Mathematically, reservoir behavior is modeled by a set of differential equations that describe the fundamental principles of conservation of mass and energy, fluid flow, and phase behavior.

Field-wide simulations are initially used to assess the viability of water and CO_2 flooding. Once a decision has been made to develop a CO_2 EOR project, Oxy uses detailed pattern modeling to plan the location and injection schedule for wells. For the purpose of operating a CO_2 flood, large-scale modeling is not useful as a management tool because it does not provide sufficiently detailed information about the expected pressure, injection volumes, and production at the level of an injection pattern. Field-wide modeling was performed by the previous owners in the1980s and 1990s and Oxy reviewed this work to inform their decision to acquire leases in 2000. Since taking over operation of the Denver Unit in 2000, Oxy has used pattern.

At the pattern level, the objective of a simulation is to develop an injection plan that maximizes oil recovery, and minimizes the costs of the CO_2 flood. The injection plan includes such controllable items as:

- *The cycle length and WAG ratio to inject water or CO_2 in the WAG process*
- *The best rate and pressure for each injection phase*

Simulations may also be used to:

- *Evaluate infill or replacement wells*
- *Determine the best completion intervals*
- *Verify the need for well remediation or stimulation*
- *Determine anticipated rates and ultimate recovery*
- *The pattern level simulator used by Oxy uses a commercially available compositional simulator, called MORE, developed by Roxar. It is called "compositional" because it can track the composition of each phase (oil, gas, and water) over time and throughout the volume of the reservoir.*

Additional details regarding Oxy's application of MORE are given in Oxy Denver Unit CO_2 Subpart RR MRV document (2015)

8.4.1 Summary and Conclusions

Occidental Petroleum Ltd. (OPL - Oxy) operates the Denver Unit in the Permian Basin of West Texas for the primary purpose of enhanced oil recovery using CO_2 flooding (CO_2 EOR) with a secondary purpose of storing CO_2 for a specified period 2016 through 2026.

- *Oxy has injected during the period 1983 through 2013, 4,035 billion standard ft^3 - Bscf (212.8 million metric tons – Mt), of which 84 Mt was produced and 128.8 Mt was stored. Oxy forecasts that the total volume of CO_2 injected will be ~ 25% of the theoretical storage capacity of the Denver Unit*

- *Discovered in 1936, the Wasson Field produces oil from the permeable San Andres dolomite formation, and with an OOIP of 4,000 million barrels is one of the largest fields in North America. The San Andres lies at a depth of 5,000 feet (1,524 m) and is capped with a 400 foot (122 m) caprock of impermeable dolomite, referred to as the Upper San Andres that has kept oil and gas trapped in the lower San Andres for millions of years.*

- *The Denver Unit is a subdivision of the Wasson Field. Oil production began in the Denver Unit in 1938 and peaked in the mid-1940s with water flooding started in the 1960s and CO_2 flooding starting in 1983. Primary recovery resulted in 17.2% of OOIP, secondary recovery 30.1% and an expected additional recovery of 19.5% through CO_2 EOR with an expected total recovery of 66.8% of the OOIP. The total OOIP in the Denver Unit is ~ 2 billion barrels (0.32 billion m^3), with CO_2 EOR estimated to recover 0.39 billion barrels (0.06 billion m^3) (NETL/ARI, 2011).*

- *There are no known faults or fractures affecting the Denver Unit, and the absence of faults has been confirmed in several ways including seismic surveys (which show the presence of faulting well below the San Andres), and operational history since the 1960s that has confirmed that there are no faults or fractures that penetrate the flood zone.*

- *As of August 2014, there are ~ 1,734 active wells (2/3rd production and 1/3rd injection). Since 1996, all wells are cemented to surface using state-of-the-art standards. Oxy pays close attention to older wells and keeps well workover crews on site in the Permian Basin to maintain all active wells and to respond to any wellbore issues that arise.*

- *All wells (both producers and injectors) are regulated by the Texas Railroad Commission (TRCC). TRCC requires that injection pressures be limited to prevent contamination of other hydrocarbon resources or pollution of subsurface or surface waters and below the reservoir fracture pressure (measured using step-rate tests).(See Section 7.1)*

- *Reservoir pressure in the unit is managed by maintaining an injection to withdrawal ratio (IWR) of ~ 1.0. Oxy also drills offsetting injectors and producers along the lease lines that balance one another (and helps contain fluids within the Unit).*

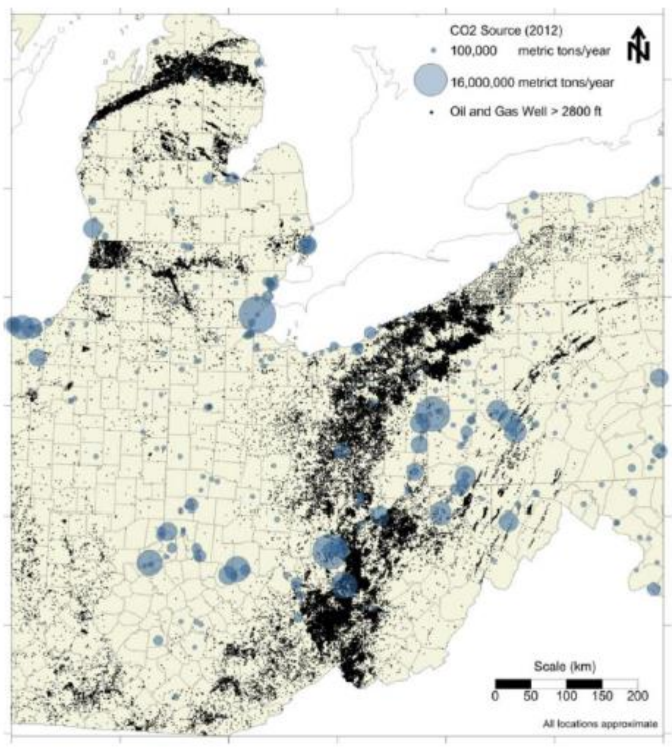
- *Oxy used simulators to model the behavior of fluids within the reservoir and uses detailed pattern modeling to plan the location and injection schedule for wells. Simulations are also used to: evaluate infill or replacement wells; determine best completion intervals; verify the need for remediation/workover or stimulation; determine anticipated rates and ultimate recovery. Oxy uses commercially available compositional simulator – MORE, developed by Roxar/Emerson (See Sections 7.1 on Regulations and Section 5.4 for Reservoir Modelling).*

8.5 CASE STUDY # 5: CO_2 INJECTION IN MIDWESTERN U.S. (SMINCHAK ET AL, 2013) AND HAAGSMA ET AL (2013)

Introduction

Wellbore integrity has been identified as a major risk factor for geologic CO_2 sequestration in areas with many old oil and gas wells. In the Midwestern United States, over 1 million oil and gas wells have been drilled since the late 1800s, and many of these wells may provide potential pathways for CO_2 migration (Figure 28). The condition of these wells varies with age, depth, geology, and location. In order to assess the risks from such oil and gas wells, a systematic investigation of well construction methods, status, and condition was performed to evaluate wellbore integrity factors and support development of geologic CO_2 storage in the region.

Figure 28 - Map of oil and gas wells over 800 m deep and large CO_2 sources in the Midwest U.S. (Sminchak et al, 2013)



Well integrity factors for carbon geo-sequestration

Wellbore integrity is considered a key risk factor for geologic CO_2 storage, since wells can act as a conduit to the overlying strata or to the surface for CO_2 migration. In some areas such as the Midwest U.S. which has some of the oldest oil and gas fields in the world with several thousands of oil and gas wells, the risks from such wells is of particular concern. Significant risk factors include poor cementing, plugging, or incomplete records of these wells while well drilling and construction technologies and plugging and abandonment (P&A) procedures and materials have varied and advanced over time. Other well integrity factors may include cement degradation, cracks, micro annulus, acid-gas zones, channeling, casing corrosion, and other long-term processes. The objective of this study was to link analysis of sustained casing pressure and cement bond logs (CBL) from a subsampling of wells to the larger dataset of wells to better define the nature and extent of wellbore integrity in the region.

Project Study Area

The project study area was defined as Lower Michigan and Ohio with thick sequences of Paleozoic age sedimentary rocks providing CO_2 storage options in both states. The Michigan Basin is the major geologic structure in the Lower Michigan peninsula, and there are few storage options in upper Michigan. Approximately 54,000 oil and gas wells have been drilled in Lower Michigan. Major oil and gas plays in Michigan are present in the Dundee limestone, Antrim Shale, Niagaran reefs, Trenton-Black River, and other rock formations. In Ohio, numerous fields are present in the Appalachian Basin in the eastern portion of the state and shallow fields are also present in northwestern Ohio. Approximately 230,000 oil and gas wells have been drilled in the state with the major oil and gas bearing formations being the 'Clinton' – Medina sandstone, Trenton-Black River, Berea sandstone, Rose run sandstone, and Utica-Point Pleasant shale. While the study focused on Michigan and Ohio, project results may be relevant to the Midwest in general and areas with older oil and gas fields.

Methods

The objective of the research was to complete a systematic assessment of wellbore integrity in the Midwestern United States using regulatory and industry information. The distribution of wellbores in the study area was determined by: (1) collection and analysis of well records, (2) examination of well plugging and abandonment records, (3) field monitoring of sustained casing pressure from existing wells, and (4) analysis of well integrity in relation to hypothetical CO_2 storage test areas. Analysis results were linked to the larger well datasets to provide guidance on wellbore integrity issues in the region.

Well Record Analysis

Well record analysis was based on existing regulatory and industry information for the Michigan and Ohio study areas. Cement bond logs were also identified and evaluated with a systematic methodology to ensure consistency. Finally, all data was analyzed with maps, graphs, and statistics to portray population and spatial trends.

Well data collection

For Ohio, oil and gas related well records were collected from the Ohio Department of Natural Resources database with a total of 229,992 wells identified, and 102,246 (44 %) listed as plugged. For Michigan, oil and gas well records were acquired from the Michigan Department of Environmental Quality Oil, Gas, and Minerals division. A total of 53,826 well records were listed for the Michigan Lower Peninsula and only a few dozen wells listed for the Upper Peninsula. Of these, 34,612 wells are listed as plugged and abandoned (~ 64%).

Well construction data were collected from a variety of sources that collect information from operators, drillers, and service companies. The wells were installed between 1890-2013, so the quality of the records varies, and since some information was not available, the results may be incomplete for some parameters.

Systematic cement bond log evaluation

A total of 1,720 cement bond logs (CBLs) for Michigan and 1,060 CBLs for Ohio were available to be accessed. These records were randomly sub-sampled to obtain 10%, or 278 logs, for analysis. A methodology to determine cement bond response was developed with minimal log response considered 0% bond (free pipe) and maximum log response considered 100% response, with the difference divided into 10% bond increments. Analysis was represented with a weighted average bond index across the cemented interval. The methodology also includes noting any indications of leakage pathways such as a micro-annulus, cracks, voids, gas-cut cement, channeling etc.

Results of the systematic bond log analysis indicated a weighted average cement rating of 0.71 for Michigan and 0.73 in Ohio. In general, most logs had at least 15 m of cement rated over 75% above the isolation zone, with decreasing cement bond index with depth.

Well Status Analysis

Well records were analyzed with graphs, statistics, and geologic visualization methods with the objective of determining the temporal, geographic, and geologic distribution of key indicators of wellbore integrity for the study area. This analysis included information on well construction/status, plugging and abandonment, and cement bond log analysis.

Plugging and Abandonment Analysis

In Michigan, 34,612 wells (~64% of all wells) are listed as plugged and abandoned, while in Ohio, 102,246 oil and gas wells are listed as plugged and abandoned (~ 44% of all wells). A random sample of 5% of plugged wells was selected from the Michigan well records (since had no state database), and plugging and abandonment records for these 1,730 wells were compiled into a database. In Ohio, plugging details for 6,390 wells were obtained from a state oil and gas database. Data compiled included number of plugs, plug depth, plug material, plug thickness, cement mix, and additive.

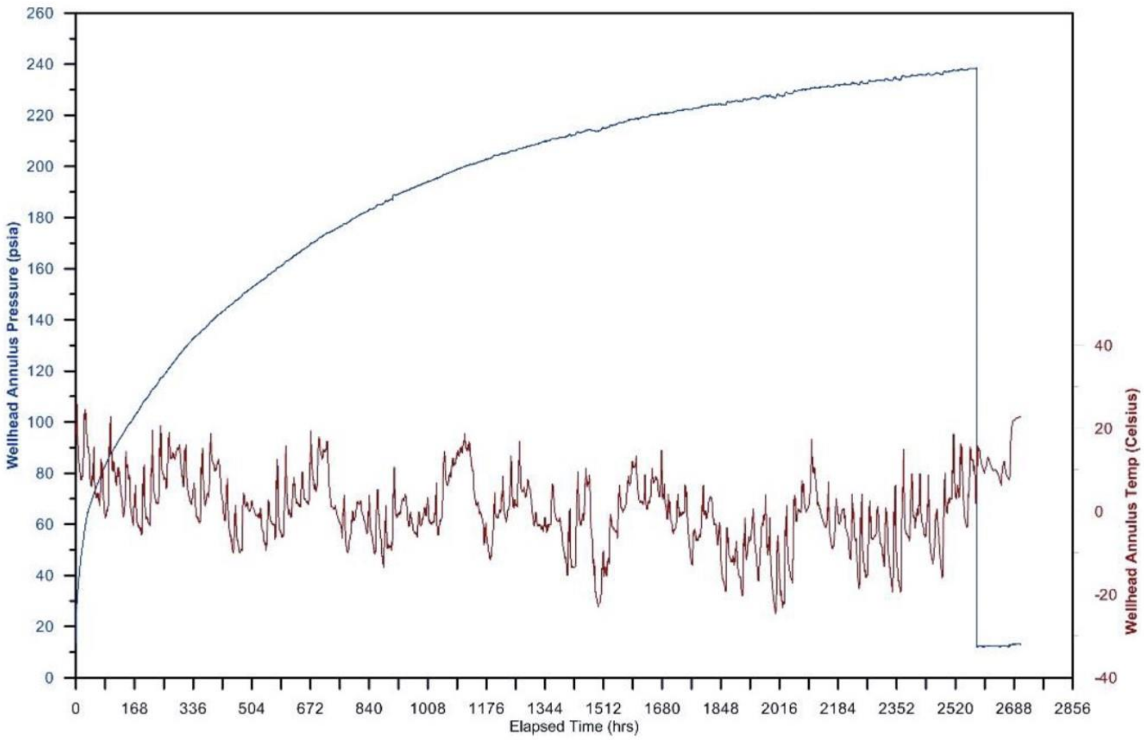
In the region, operators typically set plugs across certain water bearing zones, casing transitions, and reservoir zones to isolate these zones. The dataset accounts for 1,730 and 6,390 wells in Michigan and Ohio respectively. Wells in Michigan contain 1-6 plugs and in Ohio 1-4 plugs. Mud plugs were not included in the analysis. Most plugs in Michigan were 30-120 m thick, with some plugs over 150 m thick. Plug thickness in Ohio varied with many plugs between 60-300 m thick.

Sustained Casing Pressure (SCP) Field Monitoring

Definition of Sustained Casing Pressure (SCP) – See Section 3.4

Sustained casing pressures were monitored in thirteen wells with wellhead pressure/temperature loggers installed on the annulus port. The casing strings in these wells are cemented at various intervals, and they reflect different well completions. The wells were then vented, so the rate of pressure build-up over time could be recorded (see Figure 29 for an example pressure build-up). Gas samples were also collected to assess the source of the gas per hydrocarbon signature. Also, once the pressure had built back up to initial pressure, the volume of gas was estimated with flow meter. In general, the wells showed various pressures from 0.5 to 7 MPa, indicating various source zones, which can complicate sustained casing pressure analysis since the source of the gas may not be clear.

Figure 29 - ***Sustained Casing Pressure Buildup Data from a 1940s era well (Sminchak et al, 2013)***



<u>*SCP Analysis*</u>

SCP data from the 13 wells was first screened in an attempt to quantitatively examine the cement seal. Results indicated that analysis of data for the first 4 wells was not feasible, because the annulus was only cemented at the bottom of the cased hole, and gas entered from several shallower zones that commonly produce small amounts of gas and migrated to the surface unimpeded. However, gas analyses of these wells did confirm that the SCP observed at this field (which includes mainly older 1940s wells) did not come from the gas reservoir, demonstrating zonal isolation for the gas reservoir first penetrated over 70 years ago.

For those wells for which a flow path through the cement seal could be demonstrated, a new method called the “Defect Model” was developed to quantify cement seal quality, which is applicable to a wider range of wellbore conditions than previous methods. The defect factor for the cement, DFc , is the area of an orifice that represents the cumulative effects of all the cement leakage such as micro-annulus, cracks, conduits, etc. along the entire cemented section:

$q = DF_c \times f$(well geometry, fluid properties, ΔP)

where q is flow rate in cement, DFc is the cement defect factor and ΔP is pressure delta between source zone and the surface.

The Cement Defect Factor method was applied to 13 wells with SCP field monitoring data. Eight wells ~ 1,900 m deep wells that were cemented to surface were also analyzed and exhibited a wide range of cement defect factor results. Overall, this method proved more suitable than previous methods in obtaining consistent quantitative cement seal data than previous methods. Work is ongoing in this area.

Hypothetical CO_2 Storage Test Area Assessment

Proposed CO_2 storage assessment test areas in south-central Michigan and northeast Ohio were characterized for CO_2 storage assessment. Each test area was examined as if it were a CO_2 storage site by finding vulnerable boreholes to plug, monitor, or test the wells as per the requirements of U.S. Environmental Protection Agency Underground Injection Control (UIC) regulations for Class VI storage wells.

Test area well integrity evaluation

Well construction data were tabulated for both test areas, including well construction materials, cementing, and plugging and abandonment methods. The Albion-Scipio is the major oil field in this area of Michigan, and there is a geologic fold near this area. The Michigan site has 22 oil and gas wells that penetrate the Albion-Scipio formation at a depth of approximately 1,400 m (with most wells plugged but some have complicated lateral recompletions). The Ohio test site has 359 wells at depths of less than 1,300 m with the 'Clinton' sandstone being the major gas reservoir in this area and has a long history of oil and gas operations. Overall, neither site had any wells that penetrated the storage reservoir or immediate cap-rock, suggesting that no corrective action may be necessary at this site to address wellbore integrity concerns. However, more work is being conducted to evaluate wellbore integrity concerns for old wells.

8.5.1 Summary and Conclusions

Analyses of well records, well plugging information, cement bond log evaluation, sustained casing pressure field monitoring, and hypothetical CO_2 test areas can provide a realistic description of wellbore integrity factors in the Midwestern United States. Many of the deep saline aquifers being considered for CO_2 storage have few wells that penetrate the storage zones or cap-rock zones, and evaluation of 278 CBLs from Michigan and Ohio suggested that most wells had adequate cement above the isolation zone. Preliminary analyses indicated that intermediate zones appeared to present a larger risk for borehole migration of CO_2. Field monitoring of SCP provided a cement defect factor that reflected combined well defects.

Project results may benefit both CO_2 storage and CO_2 EOR applications. This study sheds more light on the actual risk (rather than the perceived risk) of historic oil and gas wells in the Midwest U.S. The results also show that most historic wells are much shallower than the potential CO_2 storage sites while many deeper wells (which are generally newer) are adequately plugged and abandoned or are still active.

8.6 CASE STUDY # 6: OVERVIEW OF CORE ENERGY'S CO_2 EOR PROJECTS AND OPERATIONS IN MICHIGAN

Core Energy, LLC currently operates the only CO_2 EOR projects in Michigan and the only commercial EOR project east of the Mississippi using anthropogenic or captured CO_2. In 2016, Michigan (Core Energy) produced its two millionth barrel of oil from CO_2 EOR and could potentially recover an additional 25–30%, on a field-by-field basis, of the oil volume produced during the primary producing life of a field with ongoing CO_2 EOR in the future. Core Energy performs miscible CO_2 EOR by flooding by injecting compressed and dried CO_2, removed from the natural gas produced from the Antrim Shale resource play, into one or more wells in a field. Core Energy works with numerous small Niagaran pinnacle reef fields, most of which have fewer than five operating wells. One of the benefits of using compressed CO_2 for EOR, besides an increase in oil recovery, is that the oil recovered helps to pay for the cost of capturing and building the transportation infrastructure necessary to sequester more CO_2, making the process more economical. Oil produced from CO_2 EOR is net ~70% carbon free making the process more economical Core Energy communication – Rick Pardini, May 3 2018). There are currently more than 136 CO_2 EOR projects in the United States producing ~ 300,000 barrels of oil per day. Within the Midwestern Governors Association member states, there is an estimated CO_2 EOR potential of more than 6.3 billion barrels of oil, which would require 7.5 billion metric tons of CO_2 between now and 2030, representing one-third of the total remaining primary reserves in the U.S. (Core Energy brochure, 2018).

Core Energy estimates that about 30% of the OOIP is recovered from a reef in the primary producing stage and an additional 10-20% will be recovered with CO_2 EOR. Little to no water flooding has taken place in these carbonate pinnacle reef complexes (at least one field – Charlton has been previously waterflooded), and since the injected gas is dry CO_2 they have not had any major corrosion concerns. However, in one of their new assets, which has been water flooded, they anticipate having some potential for corrosion similar to other post water flood CO_2 EOR projects like in West Texas. Production from CO_2 EOR has increased from about 60 barrels of oil per day in the mid-1990s to ~ 1,000 bbls/day at the present time, with the crude having an API gravity of 38 – 43° API and a Minimum Miscibility Pressure (MMP) of about 1,200 psi (8.27 MPa) for the CO_2 floods.

Niagaran Pinnacle Reef fields are excellent isolated and sealed containers with the anhydrite serving as a super caprock. There are over 700 such fields in the northern reef trend of Michigan, with Core energy operating a small but expanding fraction of these fields. The gas storage reservoirs with a long history of safe gas storage in Michigan are an excellent analog for the safe long-term storage of CO_2. The reservoirs being CO_2 flooded typically have very little water in them and no water drive mechanism. The well completions are designed to minimize CO_2 gravity override. The operator is open to the continued incidental storage of CO_2 in these reservoirs at the end of the CO_2 EOR project lifecycle.

In addition to CO_2 EOR operations, Core Energy is involved in CO_2 sequestration in conjunction with EOR operations in Michigan by serving as the host site for a public/private partnership (www.MRCSP.org) to research the storage potential of Michigan's oilfields and deep saline reservoir geology.

Core Energy is also actively engaged in using state-of-the-art 3-D seismic technology for oil and gas exploration and exploitation.

- *Well construction schematics of an example CO_2 EOR injection well and a CO_2 EOR production well are given in Figures 30 and 31 (from Core Injection and Production Well Schematics).*
- *A process flow diagram for Core Energy's facility is shown in Figure 32 (from Core Energy)*

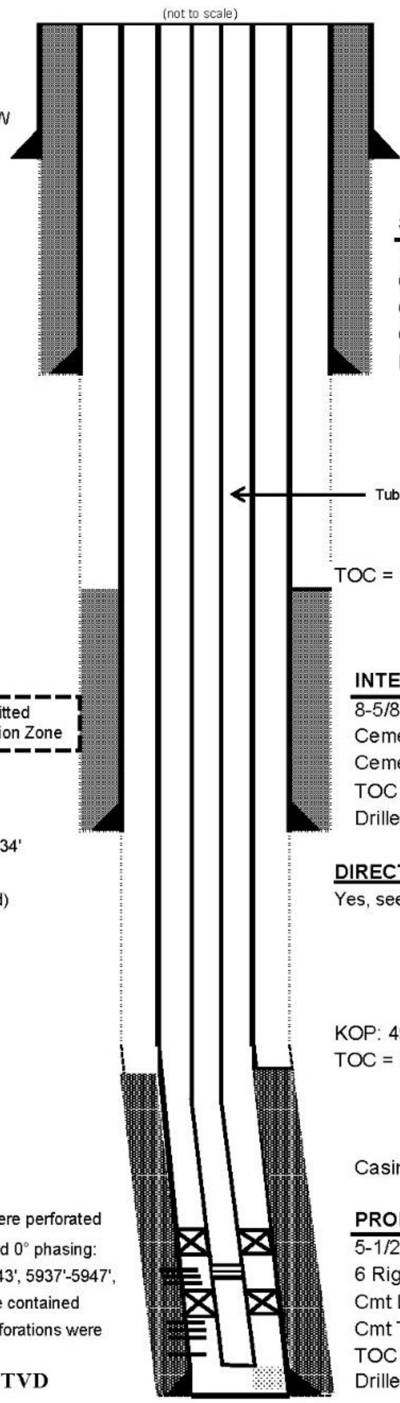
Figure 30 - *CO_2 EOR Injection Well Schematic (Courtesy Core Energy, Michigan)*

"Typical" Injection Well Diagram

KB: 1320.4'
GL: 1306.5'

Operated under the oversight of an US EPA Class II Permit

Formation Tops - based on KB		
Name	MD	TVD
BOD	857'	857'
Antrim	1,134'	1,134'
Trav Form	1,607'	1,607'
Trav Lime	1,647'	1,647'
Bell Shale	2,293'	2,293'
Dundee	2,363'	2,363'
Detroit River Group	2,601'	2,601'
Massive Anhydrite	3,125'	3,125'
Richfield	3,189'	3,189'
Amherstburg	3,372'	3,372'
Bois Blanc	3,493'	3,493'
Bass Island	3,950'	3,950'
G Unit	4,278'	4,278'
F Unit	4,315'	4,315'
F Salt	4,354'	4,354'
E Unit	5,073'	5,072'
D Unit	5,201'	5,198'
C Shale	5,245'	5,240'
B Unit	5,321'	5,311'
B Salt	5,361'	5,347'
A2 Carb	5,737'	5,649'
A2 Evap	5,839'	5,729'
A1 Carb (Ruff)	5,884'	5,762'
Brown Niagaran (Guelph)	5,970'	5,828'
Gray Niagaran	6,513'	6,242'



CONDUCTOR:
16" driven to 61'

SURFACE HOLE & CASING:
11-3/4" 42# H-40 STC @ 993'
Cement Lead: 366 sx Extenda Cem
Cement Tail: 158 sx Hal Cem Class A
Cement to surface (circ. 8 BBLS cmt to surface)
Drilled w/ 14-3/4" bit

INTERMEDIATE HOLE & CASING:
8-5/8" 32# J-55 LTC set @ 4047'
Cement Lead: 92 sx 65/35 POZ Lite, 3% CaCl, 1.69 yld
Cement Tail: 112 sx Class A, 3% CaCl, 1.18 yld at 15.6#
TOC 3050' (Temp Survey 11/21/16)
Drilled w/ 10-5/8" bit

DIRECTIONALLY DRILLED WELL
Yes, see "as drilled" directional plan.

KOP: 4940'
TOC = 5420' (CBL 12/21/16)

Casing Flag Joint 6214'-6222'

PRODUCTION HOLE & CASING:
5-1/2" 17# J-55 LTC SMLS set @ 6697'
6 Rigid Centrl per Jt from 6615' to 3538'
Cmt Lead: 118 sx ExtendaCem Lite
Cmt Tail: 180 sx CorroCem Class A
TOC 5420' MD (CBL)
Drilled w/ 7-7/8" bit

INJECTION STRING:
181 jts 2-7/8" EUE Tbg
5-1/2" x 2-7/8" SnapSet Casing Packer set at 5834'
3 Jts 2-7/8" Tbg
2.31" x 2-7/8" XA Sliding Sleeve at 5935' (closed)
1 Jt 2-7/8" Tbg
2.31" x 2-7/8" D2 On/Off Connector @ 5970'
5-1/2" x 2-7/8" AS-1X Casing Packer @ 5971'
3 Jts 2-7/8" Tbg
3' Perforated Sub @ 6075'
3 Jts 2-7/8" Tbg
3' Perfoated Sub @ 6173'
2.31" x 27/8" X Landing Nipple @ 6176'
11 Jts 2-7/8" Tbg
2.31" X 2-7/8" XN Landing Nipple @ 6532'
Wireline Re-entry Guide (EOT at 6533')

PERFORATIONS: The following intervals were perforated on 12-22-16 using 3-3/8" casing guns, 1 SPF and 0° phasing: 6274'-6284', 6135'-6145', 6094'-6104', 6033'-6043', 5937'-5947', 5914'-5924' and 5892'-5902'. All perforations are contained within the Ruff Formation/Guelph Dolomite. Perforations were treated with150 Gals/Ft of 28% FeHCl.

DRILLERS TD = 6697' MD, 6381.35' TVD

Figure 31 - *CO_2 EOR Production Well Schematic (Courtesy Core Energy, Michigan)*

"Typical" Production Well Diagram

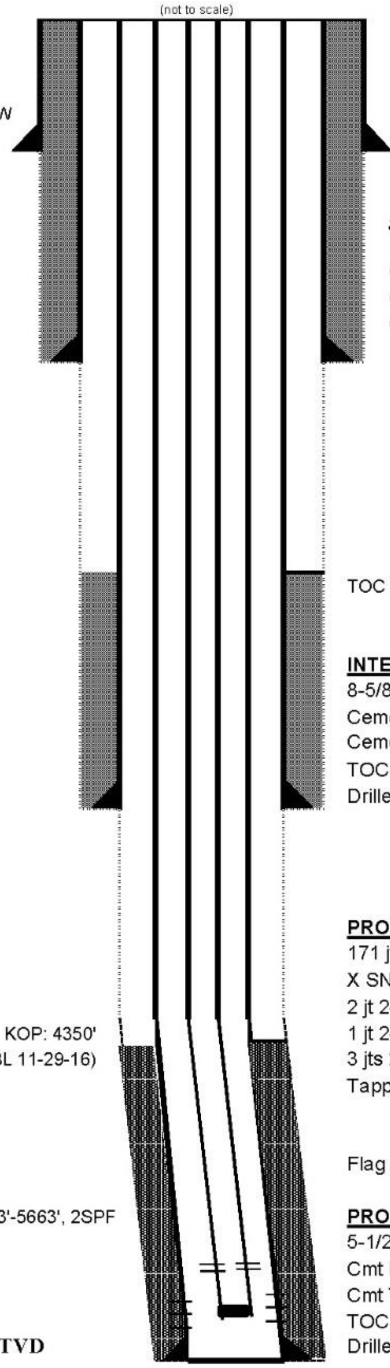
KB: 1162.6'
GL: 1148.8'

Operated under overgsight of State Permit

(not to scale)

Formation Tops - based on KB		
Name	MD	TVD
BOD	680'	680'
Antrim	1,067'	1,067'
Trav Form	1,210'	1,210'
Trav Lime	1,250'	1,250'
Bell Shale	1,899'	1,899'
Dundee	1,963'	1,963'
Detroit River Group	2,195'	2,195'
Massive Anhydrite	2699'	2699'
Richfield	2764'	2764'
Amherstburg	2937'	2937'
Bois Blanc	3126'	3126'
Bass Island	3,506'	3,506'
G Unit	3,828'	3,828'
F Unit	3,870'	3,870'
F Salt	3,904'	3,904'
E Unit	4,640'	46,332'
D Unit	4,783'	4,758'
C Shale	4,838'	4,806'
B Unit	4,903'	4,863'
B Salt	4,946'	4,901'
A2 Carb	5,334'	5,230'
A2 Evap	5,411'	5,293'
A1 Carb	5,459'	5,331'
Brown Niagaran	5,536'	5,389'
Gray Niagaran	5,875'	5,635'

USDW



CONDUCTOR:
16" driven to 89'

SURFACE HOLE & CASING:
11-3/4" 42# H-40 STC @ 811'
Cmt Lead: 335 sx Extenda Cem @ 13.6 ppg
Cmt Tail: 120 sx Hal Cem Class A @ 15.6 ppg
Cement to surface (circ. 56 BBLS cmt to surface)
Drilled w/ 14-3/4" bit

TOC = 2500' (Temp Survey 10/5/16)

INTERMEDIATE HOLE & CASING:
8-5/8" 32# J-55 ERW-FBN LTC R3 set @ 3609'
Cement Lead: 195 sx ExtendaCem Lite w/12% salt
Cement Tail: 134 sx HalCem Class A
TOC 2500' (Temp Survey)
Drilled w/ 10-5/8" bit

DIRECTIONALLY DRILLED WELL

7 Whole Cores Cut:
1) 5525'-5559' MD, 5381'-5406' TVD
2) 5559'-5568' MD, 5406'-5412' TVD
3) 5598'-5608' MD, 5434'-5441' TVD
4) 5608'-5610' MD, 5441'-5443' TVD
5) 5690'-5718' MD, 5501'-5525' TVD
6) 5718'-5749' MD, 5525'-5543' TVD
7) 5749'-5763' MD, 5525'-5535' TVD

KOP: 4350'
TOC = 4815' (CBL 11-29-16)

PRODUCTION TUBING (6/28/2017)
171 jts 2-7/8" EUE J-55 Tubing @ 5535.85'
X SN @ 5536.95'
2 jt 2-7/8" EUE Tubing @ 5601.68
1 jt 2-7/8" Perforated Tubing @ 5632.78
3 jts 2-7/8" EUE Tubing @ 5729.46'
Tapped Bull Plug @ 5729.96'

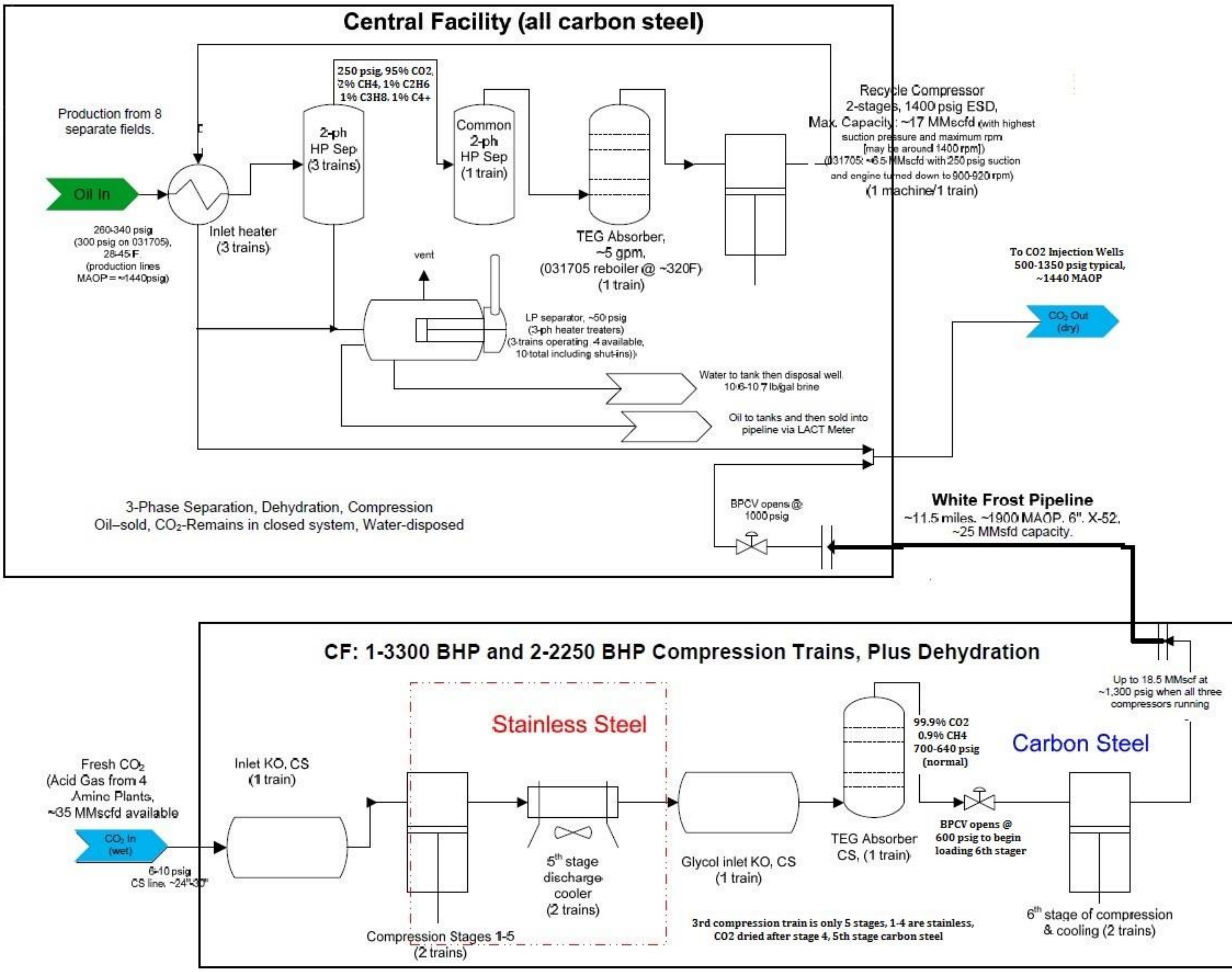
Flag Joint: 5595'-5605'

PERFORATIONS:
5586'-5594', 5606'-5611', 5628'-5638', 5653'-5663', 2SPF

PRODUCTION HOLE & CASING:
5-1/2" 17# K-55 SMLS LTC R3 set @ 6085'
Cmt Lead: 100 sx ExtendaCem Lite w/ 18% salt, 13.6 ppg.
Cmt Tail: 142 sx HalCem Class A, 1.5 Gal/Sx Latex, 15.0 p
TOC 4815' (CBL 11-29-16)
Drilled w/ 7-7/8" bit

PBTD @ 6042' MD
DRILLERS TD = 6085' MD, 5840.5' TVD

Figure 32 - ***CO_2 EOR Production Facility Process Diagram (Courtesy Core Energy, Michigan)***



As a part of this Study, a Questionnaire that was sent to Core Energy and their responses are given below, which provide a general overview of their CO_2 EOR operations. In addition, a facility visit was also conducted by the authors of this Report. We thank the management of Core Energy for facilitating this visit and sharing their valuable operational experience with CO_2 EOR injection operations in Michigan.

- *Number of wells – injectors and producers. How many are built-for-purpose CO_2 injection wells and how many are converted wells. Age of wells – both for producers and injectors.*
    - *Currently, the number of wells in ten active CO_2 EOR Projects is 36: 15 Injection (12 converted and 3 new), 13 Production (4 converted and 9 new) and 8 Monitor (6 converted and 2 new) wells. Currently Core has 27 active US EPA Class II Injection Permits and one application in the final review process with the EPA. The current number of projects and wells has increased by eight and 28, respectively, since Core Energy acquired the assets.*

- *History of fields and operations. Total volumes of oil produced and CO_2 injected, since first oil was produced and amount of incremental increase in production and recovery due to CO_2 EOR injection.*
    - *The first two projects were initiated in 1996. Since Core Energy acquired the assets, the number of projects has progressed as follows:*
        - *one project added in 2004,*
        - *one project added in 2005,*
        - *one project added in 2006,*
        - *two projects added in 2009,*
        - *two projects in 2015, and*
        - *one project in 2017 (using the onset of CO_2 of injection as the commencement date)*
    - *As of December 31, 2017, from all ten projects:*
        - *2,263,501 barrels of oil have been produced, that would not otherwise have been harvested due to the depleted nature of the reservoirs.*
        - *Total CO_2 injection (new from anthropogenic source and reinjection of produced CO_2) has been 111.8 BCF.*
        - *The net volume of CO_2 that has been incidentally sequestered as a result of the CO_2 EOR operations has been 40.1 BCF or 2.113 million metric tonnes.*
- *Is CO_2 used for injection as standalone injection for CO_2 flooding or is WAG (water-alternating-gas) employed.*
    - *To date, all reservoirs have been flooded with only CO_2 and no water or other substances have been injected. As the anthropogenic source of CO_2 becomes more limited in the future due to declining gas production from the Antrim Shale (i.e. the source), options to supplement the CO_2 will be explored.*
- *Source and volumes of CO_2 supply for EOR. Distance from source and treatment/compression and transportation details.*
    - *The source of the CO_2 used in the EOR operations comes from gas processing plants, which process Antrim Shale gas. Once the CO_2 has been dried and compressed at the source, it is transported via a network of pipelines (e.g. trunk line with laterals) to the 10 active projects. Currently, the bulk of the CO_2 is transported approximately 10-15 miles, from the source to the reservoirs.*
- *Depths of injection intervals and overlying and underlying confining intervals with geologic and engineering characteristics – porosity, permeability, thickness etc. and lateral extent and continuity.*
    - *The permitted injection zones are all in pinnacle reefs in formations known as the Ruff (A-1 Carbonate) and Guelph Dolomite (Brown Niagarn). The depth to the permitted injection zones are approximately 5,500feet (1,676 m) to 6,500 feet (1,981 m). The reefs are encapsulated by layers of impermeable anhydrite, low permeability carbonates, salts, and shales, which collectively can be more than 4,000 feet (1,219 m) thick.*

- *Is CO_2-EOR being conducted in depleted oil and gas reservoirs? Original history and background.*

  - *EOR operations are conducted in depleted oil reservoirs. Though there can be significant variations when trying to define carbonates, the reservoirs can be generally described as carbonate pinnacle reef complexes, sealed/closed under-saturated reservoirs, ranging in size from 40-400 acres, and which have undergone solution gas drive depletion during their primary production life. Primary producing recovery factors range from 30%-42% of the OOIP, which means that 58%-70% of the OOIP has been left behind. CO_2 brings new life to these depleted reservoirs and allows for incremental oil to be harvested that would otherwise be left behind.*

<u>*Drilling, Production/Injection Operations, and Well Control*</u>

- *What are the differences in equipment and procedures for drilling rigs, workover rigs and coiled tubing/wireline units when comparing work on CO_2 injection wells and conventional hydrocarbon (oil and gas wells)?*

  - *One of the main differences is in the area of well control. Since CO_2 changes phases at various temperatures and pressures, it is vitally important to continually monitor well conditions and respond accordingly. Using personnel skilled in handling and working with CO_2 is important to successful operations.*

- *What are the key differences between CO_2 and hydrocarbons that influence safety and risk assessments for well operations?*

  - *Planning ahead, knowing the properties of CO_2, continually monitoring well conditions and promptly intervening at the onset of any situation—not waiting.*

- *During wellbore **maintenance operations** did any events occur that were not predicted or were most accounted for within the risk assessment?*

  - *No, because of using personnel who are experienced and trained in CO_2 operations is a key principle, which allows crews to prepare and plan for the safe and successful handling of each job.*

- *During **wellbore operation (production/injection)** did any events occur that were not predicted or were most accounted for within the risk assessment? Same as above.*

- *How did near wellbore conditions influence CO_2 injection operations?*

  - *Almost exclusively, whenever the carbonate pinnacle reefs are drilled some formation damage occurs which is remediated with near wellbore acid treatments. Once this near wellbore damage is removed, on injection or producing wells, injection (or production) can be sustained as desired.*

- *Details on CO_2 handling and management experiences. Did CO_2 behave as predicted during injection operations (supercritical versus wet CO_2 behavior) or did any unexpected behavior occur?*

  - *Because the pressure in the depleted reservoirs is often very low (e.g. <100 psi (<689 kPA)) when a project commences, phase change can occur when supercritical CO_2 injected at the surface changes phase to a gas while travelling down the injection tubing and/or when* *entering the reservoir. This can pose some level of challenge during the early injection period, but has not been something that has detracted from projects. All of the CO_2 injected is dried using a TEG (triethylene glycol) contact tower prior to injection, which lowers the water content, however, during extremely cold winter days, hydrates can form from time-to-time. In those rare instances, adding methanol and/or heat to the injection stream is one way of alleviating the problem.*

- *Risk assessment and preparedness for potential loss of well control (including ability to deploy a rig in the event of a blowout).*

  - *Because of careful planning and using experienced and trained operations personnel, no incidents of loss of well control have ever been experienced. Remaining ever vigilant about safety and using wise operating practices must be a core value that is communicated regularly and implemented always. Wells are constructed with four strings of casing (i.e. conductor, surface, intermediate and total depth string), three of which are cemented in place; the surface casing all the way to the surface. Additionally, all wells have tubing strings run to near the permitted injection zones. Injection wells require a packer attached to the tubing string, located no more than 100feet (30.5 m) above the permitted injection zone and mechanical integrity on injection wells must be established and maintained. These things, when combined with wellheads suited for the applications and daily observation by field personnel, all serve to preclude loss of well control and have worked based on having no loss of control incidents since the onset of CO_2 EOR operations back in 1996.*

- *Are well integrity management systems (WIMS) in place to address potential risks from loss of wellbore integrity of CO_2 injection wells (given the unique phase behavior characteristics of CO_2).*

  - *As a condition of the US EPA Class II Permit, mechanical integrity must be initially achieved and then maintained on a continual basis. This is done by monitoring annular pressures, conducting fill-up tests, conducting repeat MIT's on a required cadence. In addition to these monitoring methods, company personnel check wells daily to inspect conditions.*

    Injection pressure is limited by permit, adhered to and monitored on a regular basis to ensure the injection formation is not fractured. Actual bottom hole pressure measurements are compared to material balance estimates for the fields (reefs) as another means to track reservoir integrity.

<u>Well Construction, Completion and Materials of Construction</u>

- *Well design for CO_2 injection wells and differences with standard oil and gas (hydrocarbon wells): Casing Design; Wellhead Design; Wellbore Design; Completion Design; Recompletions of existing wellbores if used for CO_2 injection and/or production.*

  - *Because of the type of reservoirs (pinnacle reefs, "steeply dipping"), the original ample CO_2 supply, no water being intentionally added to the system (e.g. WAG'ing), the CO_2 being dried prior to entering the closed system (i.e. compressors, pipelines, reservoirs, vessels) and the original infrastructure being installed for these types of conditions, carbon steel is the predominate material used. Items that have been instituted to lessen further the likelihood of failures include:*

- *CO_2-environment downhole tools (e.g. Ni-plated packers, high durometer rated elastomers on packers and tools, AB-modified tubing collars with seal rings).*
- *Surface equipment (e.g. Wellhead gaskets, and components trimmed to combat CO_2, Compressor stages pre-drying trimmed with stainless steel components).*
- *Tubing and casing strings will typically use seamless or full body normalized tubes and be on the heavier-side (i.e. lb per foot) for a bit of added safety.*

- *Downhole well schematics of typical production and CO_2 injection well. Include casing details (type, grade, weight) and cementing details (types of cements used – both opposite the injection zone and above the injection zone).*
  - *Diagrams for example injection and production wells are attached (see Figures 31 and 32).*
- *If CRA tubulars were used in addition to API tubulars and if CO_2-resistant specialty cements were used in addition to API Class G/H cements.*
  - *In some of the new wells drilled, additives (e.g. latex) were added to the cement blends as a "belt and braces" type approach to help the cement be even less porous and less susceptible to degradation, which has already been determined by studies not to occur.*
- *What have been the long-term implications for cement degradation? Has there been evidence of corrosion? Did wellbore integrity remain intact?*
  - *To date, there has been no evidence of cement degradation of any kind.*
  - *Corrosion has been very limited to non-existent due to the lack of water in the system. Corrosion inhibitors are used in certain areas (e.g. as packer fluid in annular space on wells with packers, in flowlines, or vessels). Corrosion coupons are installed in lines and monitored and continue to show very little to no corrosion.*
  - *In the few instances where wells have lost integrity, the issues have been shallow in the wellbores, far from where the EOR operations take place, and directly related to shallow formations used for disposal. Similar issues with shallow casing problems in non-EOR fields/wells in the vicinity of the ongoing EOR operations, have been documented and are similar to those few incidents observed in wells that are a part of EOR projects. Historically, once the shallow casing issues have been remediated, they have not posed any further problems.*
- *Details on specialty tubular, packers and other completion equipment used to address potential corrosion impacts from CO_2 on well integrity. See above.*
- *Control of carbon dioxide corrosion impacts on CO_2 injection wells and selection of materials of construction for both wellbores and surface facilities. See above.*
- *Details on materials of construction for surface facilities and equipment to address corrosion concerns from CO_2 (including metering, flow lines and injection lines and Xmas tree and well head valves, fittings etc. See above.*
- *Injection systems for CO_2 EOR facilities:*

- Water injection Systems. Do not WAG, so no universal injection system(s) are in place.

- CO_2 injection/Distribution Systems. One-line process flow diagram is attached (see Figure 33). All metering of CO_2 on the injection side is done via Coriolis mass flow meters. Coriolis meters are also used on the high pressure produced gas vessels (i.e. vertical, two-phase separators).

<u>Long-term Well Integrity Assessments</u>

- *How were long-term wellbore integrity assessments conducted? Fundamentally, was wellbore design modified to meet new specifications for CO_2-EOR and/or for CO_2 injection/storage wells and were different remediation measures put in place?*
  - *Whenever possible, existing wellbores are utilized for obvious reasons. Prior to a new project being implemented, old wellbores are assessed using a variety of means (e.g. physical downhole cleaning of wellbore, pressure testing, casing inspection log, cement evaluation logs) based on what is known about an existing field/well. Each field/well is handled on a case-by-case basis, tailoring an assessment plan based on what is known about each field/well.*
  - *When new wells are constructed, appropriate materials and current practices are utilized (see above) to ensure project safety and success.*
  - *Once a project becomes active, then ongoing integrity assessment is done as outline by the US EPA Permit and described previously.*
- *What new techniques were undertaken to ensure integrity of the wellbore (how was the monitoring and verification plan different from a conventional oil and gas production site)?*
  - *Operator complies with all Class II UIC permit requirements for well mechanical integrity.*
- *Were any differences noted between predicted degradation of the wellbore and any observations during or post CO_2 injection/production?*
  - *As stated previously, no degradation issues have been encountered.*
- *Was injection regularity maintained and did well integrity have any impact on achieving planned regularity? (Note: Well regularity is the ability to actually inject CO_2 regularly at the desired rates necessary to store the delivered quantity or the quantity needed for CO_2-EOR purposes. Regularity influences the design and cost of storage facilities e.g. low expected regularity will necessitate drilling additional wells resulting in increased capex costs).*
  - *In the vast majority of cases, CO_2 injection has been achieved and sustained as planned and in those few cases where it was not, it was related to reservoir issues that resulted in actions to remedy (e.g. acid stimulation to remove near wellbore damage, removal of hydrate from tubing).*
- *Management of abnormal casing pressure and sustained casing pressure (SCP)*
  - *Well and mechanical integrity maintenance and monitoring techniques. Also monitoring techniques for casing corrosion and cement degradation to assure wellbore integrity throughout its lifecycle. See above.*

- *Our understanding is that Core Energy's wells are Class II-EOR wells that are permitted, constructed and operated as per requirements for Class II-EOR injection wells (and Core Energy does not operate Class VI – CO_2 storage wells in MI).*
    - *Correct, currently Core Energy has 27 active US EPA Class II Permits and one that has been submitted and in the final review process. Core Energy does not possess any Class VI Permits.*
- *Procedures and guidelines that Core Energy follows to assure that previously abandoned oil and gas wells do not pose a threat as being a potential conduit for escape of injected fluids/CO_2 into overlying aquifers and/or to loss of wellbore integrity of existing CO_2 injection and EOR production wells.*
    - *As a part of the US EPA Class II Permit application process, an area of review (AoR) is established around each injection well, which requires a review of all wells within it. If after the review, any wells are determined to be improperly constructed or plugged, then remedial action would be required to be taken prior to the Permit being issued and authorization to injection granted.*
    - *For these reviews, available records from all sources (e.g. State regulatory agencies) are carefully scrutinized and a determination is made regarding any wells that were not properly constructed and/or properly plugged and abandoned.*
    - *Also current P&A procedures that Core Energy applies when abandoning CO_2 injection and CO_2 EOR production wells. As a part of the US EPA Class II Permit application process, a detailed plugging plan is submitted and has to be approved as a part of the Permit process. All plugging, which we have not yet done any, will be done in accordance with the EPA Permit and Michigan DEQ guidelines.*

8.6.1 Summary and Conclusions

Core Energy, LLC currently operates the only CO_2 EOR projects in Michigan and the only commercial EOR project east of the Mississippi. In addition to CO_2 EOR operations, Core Energy is involved in CO_2 sequestration in conjunction with EOR operations in Michigan by hosting a public/private partnership to research the storage potential of Michigan's oilfields and deep saline reservoir geology. This Case Study includes Questionnaire responses received back from Core Energy, LLC related to their CO_2 EOR operations in Michigan and we are grateful for their input and participation in this Study.

Additional details are summarized below:

- *Core Energy estimates that about 30% of the OOIP was recovered in the primary stage and an additional 10-20% will be recovered with CO_2 EOR. Production has increased from about 60 barrels per day in the mid-1990s to ~1,000 barrels/day at the present time. API gravity is 38-43^0 and MMP is 1,200 psi (8.27 MPa).*
- *Injection is in carbonate pinnacle reefs in the Ruff (A-1 Carbonate) and Guelph Dolomite (Brown Niagran) formations at depths of between 5,500 feet (1,676 m) to 6,500 feet (1,981 m). The overlying anhydrite layers can be as much as 4,000 feet (1,219 m) thick.*

- *Currently have 15 injection wells (12 converted and 3 new), 13 production wells (4 converted and 9 new), and 8 Monitor wells (6 converted and 2 new).*

- *No water flooding has taken place, and since the injected gas is dry CO_2 have not had any major corrosion concerns. However, in one of their new assets, which has been water flooded, they anticipate having some corrosion concerns similar to other post water flood CO_2 EOR projects as in West Texas. They are also addressing some potential near-wellbore injectivity and reservoir challenges in this new asset, as they move ahead with CO_2 EOR operations. EOR operations are conducted in depleted oil reservoirs.*

- *Niagaran Pinnacle Reefs are excellent isolated and sealed containers with the anhydrite serving as a super caprock. The natural gas storage reservoirs in Michigan are an excellent analog for the safe long-term storage of CO_2.*

- *The reservoirs being CO_2 flooded typically have very little water in them and no water drive mechanism. The well completions are designed to minimize CO_2 gravity override.*

- *In some of the new wells drilled, additives (e.g. latex) were added to the cement blends as a "belt and braces" type approach to help the cement be less porous and less susceptible to degradation, which has not occurred to date.*

- *Corrosion is limited due to absence of water in the system. Corrosion inhibitors are used in certain areas and corrosion coupons are installed in lines and have shown very little to no corrosion.*

- *Have had shallow well integrity issues, due to non-EOR disposal activities, but have been remediated when they occur without any major impacts.*

- *The source of the CO_2 is from gas processing plants which process natural gas from the Antrim Shale resource play. Once the CO_2 has been dried and compressed at the source, it is transported via a network of pipelines.*

- *The operator is open to the continued incidental storage of CO_2 in these reservoirs at the end of the CO_2 EOR project lifecycle.*

9.0 SUMMARY AND CONCLUSIONS

Geologic storage/sequestration of carbon dioxide involves injection of large quantities of CO_2 injection into primarily deep saline aquifers for storage purposes or, where feasible, into oil and gas reservoirs for EOR purposes. The literature and experience from industrial analogs indicates that wellbores (active/inactive or abandoned) may represent the most likely route for escape of the injected CO_2 from the storage reservoirs. Therefore, sound injection well design and life-cycle well integrity, operation and monitoring are of critical importance in such projects.

Well integrity issues impact well regularity (the ability to actually inject CO_2 regularly) at the desired rates necessary to store the delivered quantity or the quantity needed for CO_2 EOR purposes. Regularity of CO_2 injection influences the design and cost of storage facilities and needs to be addressed in the planning stages of storage projects to assess future well performance. In CO_2-rich environments, it is important to identify equipment and procedures that may cover drilling, completion, operation, interventions and abandonment.

The significant base of knowledge of how to manage pure CO_2 operations that exists in the U.S., and to a lesser extent in Canada and Europe, allows for a comparison to be made on methods and technologies for handling CO_2 to those required for hydrocarbon extraction. CO_2 EOR projects, along with wells drilled in H_2S-rich environments, gas storage projects and high pressure high temperature (HPHT) projects, have delivered technological advancements in well designs and materials, such as improved tubulars and cements that are resistant to the corrosive effects of CO_2 both in the downhole and surface environments.

In-depth case studies have been presented in this Study and represent different operating settings: onshore CO_2 EOR, offshore CO_2 EOR, and CO_2 storage projects located in the Permian Basin, Texas as well as offshore Brazil and other locations in the world. The case studies focus on industry experience with wellbores that are used for the production or injection of CO_2.

A brief overview of current regulations and regulatory jurisdictions for CO_2 EOR and CO_2 geologic storage operations in the United States, Canada, United Kingdom, European Union, Australia and Brazil are also included in this Report.

Broadly stated, the challenges related to long-term CO_2 storage, principally in deep saline aquifers and to a lesser extent in depleted oil and gas reservoirs, can be broken down into two main categories: (1) Well

Integrity challenges and (2) Injectivity or Regularity challenges. These have been discussed in this Study and are briefly summarized below with recommendations where appropriate.

Well Integrity Challenges for CO_2 Storage Wells

Wellbore integrity is critical for the success of both CO_2 storage as well as CO_2 EOR injection wells. A proper casing and cementing design is the first critical element in ensuring that a CO_2 GS well will maintain its well integrity throughout its operating life-cycle. Analysis of injection and production data from the Norwegian sector shows that thermal cycling can affect wellbore integrity especially in injection wells (See Vignes, 2011, Randhol et al, 2008 and Section 2.1.2 – Casing Design). Casing design software such as WELLCAT™ is currently widely used by most operators to ensure that the wellbore integrity is maintained throughout its life cycle, particularly for applications such as HPHT, deep water, shale oil/gas hydraulic fracturing, CO_2 injection etc. where complex tubular loads/stresses are imposed (See Section 2.1.2).

A large area of interest in Norway at the moment is the requirement for scaling up each CCS process to reach commercial scale. Therefore maintaining life-cycle and long-term well integrity becomes crucial for the success of these projects and the safe storage and security of the stored CO_2.

Intermittent supply of CO_2 has implications for well integrity and on-off injection leads to cyclical heating and cooling potentially impacting well integrity. Thermal effects can lead to debonding (between the cement and casing and/or rock interface), nucleation (e.g. salt precipitation) and borehole deformation) (See Section 5.0 for further discussion on thermal effects on CO_2 injection well integrity).

In a CO_2 injection well, the principal well design considerations include pressure, thermal stresses, corrosion-resistant materials (tubulars and cements) and production and injection rates. The technology for handling CO_2 has already been developed for EOR, natural gas storage and acid gas injection. Horizontal and extended reach (ERD) wells are good options for improving the rate of CO_2 injection from individual wells.

Proper maintenance of CO_2 injection wells is necessary to avoid loss of well integrity. Any annulus pressure buildup should be monitored and if SCP is indicated, diagnostics should be performed and appropriate remedial steps taken to restore well integrity or the well shut-in, pending repair.

Plugging and abandonment procedures are also important to ensure that the injected CO_2 will not escape or migrate out of the stored reservoir and/or saline aquifer.

Due to the unique characteristics of CO_2 (see Section 4.0 and Appendix 2), the preparation and implementation of a written environmental, health and safety (EHS) plan is a pre-requisite prior to initiation of any CO_2 injection project (see Section A7.4).

Summary of Findings from Incidents/Case Studies of Loss of Well Control (LWC) and Blowouts

The Case Studies of various Loss of Well Control (LWC) and Blowouts that have occurred and its prevention have been presented in Sections 6.2 and 6.3. Some of the significant lessons learned are summarized below:

- *Both human factors and unforeseen reservoir conditions can contribute to their occurrence, and safety procedures, in-depth personnel training and specialized equipment is used to minimize their likelihood.*

- *The tremendous expansion of supercritical CO_2 pressure containment is lost is of great significance from a well control perspective. This flow behavior is almost explosive in its violence, and usually not expected not by field/rig workers. Often, only a small volume of supercritical "liquid" CO_2 in the wellbore is enough to trigger the process, causing the well to blowout in a matter of seconds. Reaction time is minimal and some equipment, particularly manual BOPs and stab-in safety valves, cannot be installed and closed fast enough to avoid complete liquid expansion from the well and total loss of pressure control.*

- *Several practical procedures can be used to reduce loss of well control (LWC) incidents including blowouts and to mitigate the adverse effects if one should occur. These include periodic (daily and/or continuous) monitoring of injection pressures and temperatures (both surface and bottom hole), annuli pressures, well integrity surveys (both internal and external), improved BOP equipment maintenance, improved crew awareness and training, contingency response and emergency response training.*

- *Failures from CO_2-related corrosion can cause loss of well control. In some wells in CO_2 floods that were drilled in the 1940s and 1950s, cumulative corrosion impacts are a problem. It is important to make older wells equipped with corrosion-resistant tubulars and also wells that have been converted to CO_2 service.*

- *In two of the case studies during workovers, high-rate CO_2 from the well had damaged the ram packers and damaged the BOP. Also, the blind rams could not be closed as they were frozen in place and there was ice buildup in the BOP.*

- *This was an active CO_2 injector that was being converted to reservoir pressure monitoring. The well was killed, injection tubing pulled and the old packer removed. The next day, CO_2 flow was coming out the top of the BOP –it appeared that the pipe rams had failed.*

- *In another workover on a CO_2 injector, pipe rams were closed but failed to seal around a small diameter stinger run at the bottom of the tubing to clean out the well. The well was killed by bull-heading brine down the casing.*

- *During development drilling of a CO_2 production well in Colorado, the well blew out, and after several attempts to kill the well with conventional weighted muds failed, the well was killed by the dynamic kill method. This method proved effective in this case where hydraulic constraints severely limited weighted-mud injection rates.*

- *A blowout occurred while repairing a surface casing vent flow on a dual string water and CO_2 injection well. ERCB's analysis concluded that the failure resulted from: (1) top packer failure which occurred in 2009 during a packer isolation test was not repaired by the operator allowing CO_2 to enter the wellbore and (2) production casing failure occurred at approximately 60 m from surface. A combination of factors contributed to the production casing collapse including the heating and cooling cycles involved with injecting water and CO_2 and associated tensile stresses and there was an indication of some external corrosion at the failure point.*

- *During a well workover in Gaines County, TX, news reports suggested that the well had a surface casing rupture and flowback issues and CO_2 flow had caused the flowback equipment to be frozen, that led to the uncontrolled release of CO_2 and H_2S.*

- *There was an uncontrolled release at an offset abandoned well during ongoing CO_2 flooding at an EOR field in Mississippi. The old abandoned well had its casing removed and the 2,000 foot (610 m) deep hole vented CO_2, oil and drilling mud for 37 days. A relief well was drilled and the flow was stopped.*

- *In a study of blowouts in Texas (Porse et al, 2014), there were 159 recorded blowouts in the selected Districts from 1998 to 2011. For District 3 (located in the Texas Gulf Coast with very few CO_2 EOR wells), drilling was the riskiest stage, while in Districts 8 and 8A (located in the Permian Basin with the largest number of active CO_2 EOR wells) workovers had the highest risk.*

- *Frequency of blowouts in California's District 4 (includes steam flood wells and produces 75% of California's oil production) decreased dramatically during the period 1991 – 2005 and is believed to be a result of increased experience, improved technology and/or changes in the safety culture in the oil and gas industry, suggesting that blowout risks can also be lowered in CO_2 storage fields.*

- *The API study that looked at 14 of the 19 LWC incidents (annular flows) that occurred in the U.S. Outer Continental Shelf (OCS) showed that: (1) Most of the LWC incidents took place during or after cementing surface casing, (2) In recent years (2003-2004), these events involved deep casing strings with no occurrence of LWC incidents in surface casing cementing operations, (3) most wells used a mudline/hanger suspension system, (4) Frequently the annulus between the surface casing and conductor casings was washed out to a point 30 to 50 feet below mudline after cementing. Washing out this annulus resulted in a small but possibly very significant reduction in the hydrostatic pressure while also impairing the operation of the BOP and diverter (wash pipes in the annulus prevents sealing).*

<u>Materials of Construction (Tubulars and Cements) for CO_2 Storage Wells</u>

Because of the corrosive effects of carbonic acid H_2CO_3, on metal components, induced by the alternating water and gas (WAG) injection cycles during CO_2 EOR operation, a significant fraction of scientific and technical work has been devoted to developing robust solutions to corrosion problems. Supplemental work has also been done on identifying and developing elastomeric materials for packers and seals that can withstand the solvent effects of supercritical CO_2 that induce swelling and degradation. Throughout this process, the underlying strategy of the industry has been to select materials based on their durability and corrosion resistance. Today, the material improvements presented in Table 6 of this Report as well as the special tubing handling and installation techniques enables operators to routinely expect a tubular service life on the order of 20 to 25 years (Contek/API, 2008).

- *Carbon steel casing used in CO_2 injection wells can be subject to corrosion when exposed to wet CO_2 and/or associated formation fluids if not properly protected. In CO_2 storage injection wells, CO_2 is usually injected in the supercritical state and the corrosion risk is low. However, the corrosion rate increases when the injected stream comes into contact with water, with potential water sources such as connate water, free water in the cement or free water resulting from capillary condensation. After the injection phase, during the long-term storage phase, the supercritical CO_2 can be hydrated with water present in the reservoir and wet CO_2 and the resulting acid brine can lead to potential degradation of the cement sheath protecting the casing.*

- *Use of corrosive resistant alloy (CRA) casings/liners etc. in lieu of carbon steel casing provide enhanced corrosion protection for severe CO_2 service but may have the downside of increased costs and with decreased injection capability. Due to the corrosive and highly solvent characteristics of supercritical liquid CO_2, special attention must be paid to rubber and plastic components such as packing and sealing elements. An integrated corrosion engineering approach should be utilized to optimize the life-cycle material and corrosion mitigation costs with the potential to allow well designs that take advantage of carbon steel tubing in conjunction with CRA liners, with significant cost savings while overcoming injection capacity limitations.*

Recommendations for Cement Systems and Zonal Isolation for CO_2 Injection Wells

Extra care and attention has to be paid to the design and execution of cement jobs for both surface, intermediate and production casings (most regulatory agencies mandate the surface casing to be cemented back to surface). Cement evaluation tools such as Ultrasonic Imaging Tool (USIT)/Segmented Bond Tool (SBT)/Isolation Scanner will need to be run to evaluate the quality of the cement bond to the casing and to the formation, in addition to zonal isolation tests such as FITs (formation integrity tests) to assure isolation at the casing shoe.

- *Based on the available information, the design of the cement slurry may use Portland cement as its base, provided efforts are taken to reduce the permeability of the set cement, reduce the concentration of available reactive species and/or protect those reactive species through use of carefully selected additives. Lower density system should use extenders that will allow permeability reduction which include flyash systems, additives such as found in the tri-modal systems and specialty additives that protect the reactive species in Portland cement. The use of silicate extenders or only bentonite is not recommended.*

- *Portland cements used in oilfield applications have been found to provide adequate seal and zonal integrity in several CO_2 EOR projects (both continuous CO_2 flooding as well as water-alternating-gas/WAG applications). However, in some projects, it may be required to utilize CO_2 resistant and* *specialty cements to avoid degradation and corrosion impacts resulting from CO_2 injection into deep saline aquifers.*

- *Non-Portland systems that are resistant to CO_2 are commercially available though do require additional planning to assure proper design and prevention of contamination during the operations. These systems are not as readily available as conventional Portland systems, and thus may not be available in all areas. As noted the decision to use these systems is not trivial and requires considerable planning for logistics and operations.*

Injectivity/Regularity Challenges for CO_2 Storage Wells versus CO_2 EOR Wells

The regulatory requirements in the U.S. require CO_2 storage wells to demonstrate well integrity over a longer time-frame as compared to a much shorter time frame for CO_2 EOR projects (25-40 years). Initial industry concerns about CO_2 injection, especially during the WAG process in terms of controlling the higher mobility gas: water-blocking, corrosion, production concerns, oil recovery, and loss of injectivity have been addressed with careful planning and design along with good management practices, except loss of injectivity, which is a key variable in determining the success of a CO_2 project.

- *Reservoir quality information is particularly sparse for deep saline aquifers, resulting in large uncertainties in estimations of injectivity, sweep efficiency and storage capacity. Therefore, it is critical to develop efficient and cost-effective injection strategies that maximize the injection rate and volume and decrease the required number of wells.*

- *Modeling studies and experience from existing operations (i.e., In Salah) have shown that one major limiting factor for CO_2 storage is the injectivity of the injection horizon, which in turn is limited by the requirement that the maximum permitted bottom hole injection pressure should not exceed the fracture pressure of the injection formation and of the overlying confining layer above the injection horizon. This requirement (US EPA and Texas Railroad Commission and other regulatory agencies in the U.S.) is in place to ensure that the integrity of the sealing cap-rock is not compromised. Options to be considered to increase injectivity are the use of horizontal wells and hydraulic fracturing stimulation of the injection zone.*

- *Numerical models are being successfully applied to adequately capture impacts of reservoir heterogeneity, multiphase flow behavior and fluid-rock interactions on the pressure distribution in the subsurface. Still, more data from actual storage projects is needed to history match and verify model predictions and calibrate the models.*

- *CO_2 injection can alter the mechanical properties of the reservoir rock by inducing chemical reactions (dissolution and precipitation of minerals), in particular CO_2 precipitation in calcite. Calcite precipitation can threaten the injection by cementing the reservoir around the rock and the related dissolution of the matrix can lead to the risk of subsidence and fracture. Carbonates are the first minerals to dissolve and these dissolutions occur very fast.*

- *A number of CO_2 floods have seen higher gas injection relative to pre-water flood injection with some other projects showing higher CO_2 injectivity after successive WAG floods. Simulations indicate that CO_2 injectivity is much higher in reservoirs with crossflow when accounting for phase behavior and mixing (Chang et al, 1994). Enough CO_2 solubility in follow-up brine injection has been reported* *during WAG cycles to raise unsaturated brine injectivity to three to five times the saturated brine injectivity. Increased brine injectivity during WAG cycles after the first slug of CO_2 also has been attributed to the combined effects of heterogeneity, crossflow, oil-viscosity reduction, CO_2 sweep, CO_2 channeling, compressibility and solubility of CO_2 in injected brine near the wellbore (Rogers et al., 2001).*

- *Injectivity reduction after CO_2 WAG injection has occurred frequently in West Texas, as well in the Brent formations in the North Sea after hydrocarbon gas injection. Field data from a West Texas field suggests that reduced injectivity is an in-depth (far-field) phenomenon and not a near wellbore condition such as skin or high gas saturation around the injector (Rogers et al, 2001).*

- *Several coupled physical and chemical processes may occur during the injection period depending on time and location within the reservoir. Far-field regions are facing long-term reaction where flow of gas and water at a reduced rate may induce near fluid-rock equilibrium. In contrast, near wellbore regions are subjected mainly to gas a high flow rate where dissolution/precipitation may drastically increase/decrease injectivity (Cailly et al, 2005).*

- *Wettability is a complex parameter in injectivity reductions. Gravity forces dominate in water-wet conditions while viscous fingering is dominant in oil-wet conditions. Low injectivity in the carbonate reservoirs of West Texas is probably caused by the oil-wet or mixed-wet behavior of the rocks.*

- *Trapping and bypassing of gas, like wettability, is a complex parameter in injectivity reductions. Trapped gas creates hysteresis effects and a reduced relative permeability to water, especially in oil-wet or mixed-wet reservoirs.*

- *Some experimental observations like the abnormal pressure drop response obtained under a high injection rate suggest that solid particle displacement can occur leading to severe permeability impairment.*

- *Increased scaling problems in West Texas CO_2 floods have been reported by several authors. Lower bottom hole temperature and the presence of sulfate containing water increases gypsum scaling tendencies and decreases calcite scaling tendencies. Gypsum scaling predominates in the wellbore, while calcite scale is more likely to occur in low-pressure surface equipment.*

- *Paraffin problems have been reported in many CO_2 EOR fields. Conditions favorable for paraffin deposition possibly are created when CO_2 expands as the reservoir fluids flow through into the wellbore and up the tubing and annulus. Methods used to handle paraffin deposition include: use of hot oiling or hot water combined with a paraffin solvent, pumping heavy aromatic solvents downhole, and mechanical cleanouts. Methods to prevent paraffin deposition include: increase back-pressure on the wells to keep both CO_2 and light-end hydrocarbons in solution, use of down-hole heaters, and use of crystal modifiers to raise the cloud point.*

- *Increased asphaltene precipitation has occurred in many CO_2 floods, not during primary or water flood but after CO_2 breakthrough. Asphaltenes can plug up plungers, clog wellheads and cause plugging in tubulars, chokes, surface and production lines, and is most severe during cold weather and the concentration of CO_2 in the oil. Generally, production declines are due to production equipment problems and not due to deposition in the reservoir. Keeping back-pressure has been successful in preventing asphaltene deposition.*

- *Permeability impairment due to CO_2 that dissolves water with subsequent salting out of NaCl has been reported around several gas producing wells, especially in high pressure high temperature (HPHT) wells which are characterized by very high salinity brines with a similar problem reported for the injection of dry natural gas in saline aquifers during gas storage operations. Precipitation of salts, mainly halite (NaCl), due to water vaporization, can result in severe injectivity impairment around injection wells where CO_2 is injected in saline aquifers.*

- *Numerical modeling studies have also shown the potential for well injectivity losses due to halite impairment in CO_2 storage wells (Bacci et al, 2011, Carpita et al, 2006). Studies suggest that a high CO_2 injection rate should allow the injection process to continue with limited impact on injectivity, even if significant halite precipitation takes place (Carpita et al, 2006).*

- *Since pressure build-up due to injection in both saline and depleted oil and gas reservoirs is a major limiting factor for large-scale geological storage, pressure-management strategies will need to be considered for most CCS projects. The use of water production (pressure relief) wells as proposed for the Gorgon project is one obvious solution, along with the use of horizontal wells.*

- *Use of highly deviated and/or horizontal wells have the potential in providing increased injection capacity for the large anticipated injection volumes, but may pose potential problems as it relates to proper cementing and zonal isolation and subsequent well intervention activities. Use of swellable packers (that swell in contact with well fluids) may provide an option.*

- *Co-injection of water and CO_2 has been successful in CO_2 EOR and should be directly applicable to CO_2 geological storage.*

CO_2 Storage in Deep Saline Aquifers versus CO_2 Storage in Depleted Oil and Gas Reservoirs

As stated earlier, two main types of reservoirs are considered for geological storage of CO_2: deep saline aquifers and depleted oil and gas reservoirs. The former offers a very large potential capacity and more uniform distribution but with limited characterization of the reservoir engineering and geologic properties (including the caprock seal). The latter offers smaller overall capacity, but with a reduced risk due to a better knowledge of the geologic and engineering properties. However, to utilize depleted oil and gas reservoirs for long-term storage of CO_2, the following factors need to be considered:

- *CO_2 injection can alter mechanical properties of the reservoir rock by inducing chemical reactions. Precipitation of salts can result in injectivity impairment (Bacci et al, 2011, Hansen et al, 2013 and Sminchak et al, 2014). Some studies suggest that a high CO_2 injection rate should permit the injection process to continue with limited impact on injectivity even if significant halite precipitation takes place (See Section 5.3). Additional major factors that influence CO_2 well injectivity (Torsaeter et al, 2018) include: fines migration, geomechanical factors (like borehole deformation), chemical/thermal factors, geological factors and rock heterogeneity (Torsaeter et al, 2018 and Section 5.3).*

- *During injection, the pore pressure increase induces reservoir expansion. This phenomenon can result in shear stresses at the reservoir and cap-rock boundary. For anticline reservoirs, large horizontal stresses can develop at the apex of the structure. In order to avoid this deformation, a preliminary geomechanical study is required to identify the maximum allowable pressure increase in the dome and related injection parameters.*

- *Depletion can cause pore collapse in the reservoir, with an associated loss of injectivity and storage capacity and can weaken the cap-rock and bounding seals/faults and even well completions, resulting in potential loss of wellbore integrity.*

- *Oil and gas reservoirs are intersected by many wells, and stricter regulatory requirements may require operators to re-confirm the quality of zonal isolation, by recompleting or working over wells that will be exposed to CO_2.*

- *Low reservoir pressure may also mean that injection of CO_2 in a dense phase may lead to reservoir fracturing and strong thermal effects resulting in injectivity and containment problems. Pressures must be monitored and maintained to prevent formation fracturing and potential loss of containment. The impacts of thermal cycling must be considered in the casing and cementing design.*

- *Uncertainty on capacity and injectivity is clearly lower for depleted reservoirs, giving them a net potential economic advantage, whereas the uncertainty on well containment favors saline formations, which are intersected by fewer wells.*

- *High injection pressures combined with low injection fluid temperatures can induce hydraulic fracturing which can affect the bounding seals (cap-rock and overburden). Depleted reservoirs have a lower risk from potential fracturing, since re-pressurization can be done up to a pressure that is lower than or equal to the original reservoir pressure.*

- *Geomechanical models are required to determine the maximum injection pressure that will not induce fractures and to determine the in-situ stresses and faults, and fault reactivation hazard. The fault reactivation hazard induced by in-situ stress changes is affected by factors such as the thickness, lateral extent and shape of the reservoir, the mechanical properties of the reservoir and the surrounding formations, and the presence, orientation, and strength of existing faults within or around the reservoir. Injection wells should be located as far as possible from faults.*

- *Injection wells should intersect the highest permeability zones of the reservoir with the use of horizontal wells to be considered as an option for increased injection capacity.*

- *Well placement should also be based on optimum positioning to sustain injection rate as well as longer-term CO_2 migration taking account of its buoyancy.*

CO_2 Storage Well Costs (See Section 2.1.10)

Storage costs strongly correlate with injectivity and storage capacity. Given the uncertainty in predicting the true injectivity, the variations in injectivity parameters have a significant impact on CO_2 storage economics. For a typical coal-fired power plant up to several million tons of CO_2 will have to be injected each year for storage over a period of 30-40 years. Operations at Weyburn and Sleipner are of this order of magnitude. In the case of CO_2 storage in a deep saline aquifer, a major economic objective is to minimize the number of injection wells. Due to the size of the Utsira aquifer at Sleipner and the high permeability of the receiving formation, CO_2 can be injected at a high rate without major injectivity problems or significant pressure increase. In less favorable locations, injectivity and injection regularity may become a crucial technical and economic challenge.

Given the uncertainties in predicting reservoir characteristics and properties, there will be a range of views on injectivity and the economics of CO_2 storage operations (number and type of wells etc.). Therefore, different operators may adopt different approaches in their injection well design strategies, similar to that in the exploration and production of oil and gas resources.

Existing pilot, demonstration and commercial storage projects have demonstrated that CO_2 geological storage is technically feasible. However, these projects do not collectively operate at a scale that is necessary to reduce greenhouse gas emissions significantly. The infrastructure (platforms, separation/treatment facilities, compressors, pipelines, CO_2 source, import and distribution facilities etc.) for injecting CO_2 will be an order of magnitude larger than current CO_2 EOR installations.

In summary, industry experience, particularly with CO_2 EOR wells (both for CO_2 continuous injection as well as for CO_2 WAG - water-alternating-gas) shows that new CO_2 storage injection wells can be suitably designed to allow well integrity to be maintained in the long-term, and concerns from long-term cement degradation and corrosion can be suitably addressed in the design and construction of these wells. Industry experience also indicates that CO_2 storage injection wells can also maintain long-term wellbore integrity if designed, constructed, operated and monitored as per current state-of-the-art design specifications and regulatory requirements. Stresses on casing and cement integrity from thermal cycling should also be adequately addressed in the design stage, as this has been shown to be an important life cycle well integrity risk criteria, especially in injection wells in the Norwegian sector of the North Sea. Software such as WELLCAT™ is widely used to address the various loads imposed on the tubular and cements during the lifetime of the well (covers drilling, production – including stimulation/fracturing, conversion of well application and eventual plugging and abandonment phases). Risks from legacy wellbores can also be adequately addressed as long as sound engineering practices and compliance with current and more stringent regulatory requirements are complied with.

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APPENDICES

APPENDIX 1 - DEFINITIONS

The Standard Operating Practices (SOPs) for Designing, Constructing, and Operating CO_2 Injection Wells presented in Appendix 3 and this Report may or may not cite publications that are listed in Appendix 4, and where such reference is made, it shall be to the edition listed including all amendments published thereafter. Those references not cited in the text are included for information purposes.

The following definitions shall apply in this Standard:

Area of review - geographical surface and geological subsurface area for a specific CO_2 injection project. This includes EOR and the disposal reservoir(s), the land surface for onshore projects, or the sea floor surface for offshore projects, as designated for assessment of the fate and effects of injecting CO_2 by the country, federal, provincial/territorial, or state regulators, as applicable. In the U.S., the AoR for Class II and Class VI wells is defined by a radius of ¼ mile (402m) around each vertical injection wellbore and should encompass both the vertical and horizontal legs of the planned well (if it is a horizontal well).

Balanced cement plug — the result of pumping cement through drill pipe, workstring, or tubing until the level of cement outside is equal to that inside the drill pipe, workstring, or tubing. The pipe is then pulled slowly from the cement slurry, leaving the plug in place. The technique is used in both open hole and cased hole applications when the wellbore fluids are in static equilibrium.

Biosphere (in the context of CO_2 injection) — the realm of living organisms in the atmosphere, on the ground, in the oceans and seas, in surface waters such as rivers and lakes, and in the subsurface at depths where protected groundwater is present as defined by regulations. Said rules in the USA for protected groundwater typically are aquifers where the water's salinity is less than 10,000 mg/L. The biosphere also includes all water existing in the same realm.

Casing — the pipe material placed inside a drilled hole to prevent the surrounding rock from collapsing into the hole.

Note: *The two types of casing in most injection wells are (a) surface casing, i.e., the outermost casing that extends from the surface to the required distance below the base of the lowermost protected waters; and (b) long-string casing, which extends from the surface to or through the injection zone.*

Casing shoe — a reinforcing steel collar that is screwed onto the bottom joint of casing to prevent abrasion or distortion of the casing when it is forced past obstructions on the wall of the borehole.

Cement — material used to support and seal the well casing(s) to the rock formations exposed in the borehole. Cement also protects casings from corrosion and prevents movement of injected CO_2 up the borehole (See Tables A5-1 and A5-2 for listing of regular API cements and specialty cements including CO_2 resistant cements).

Closure period — the period in a project's life cycle marked by the cessation of injection. This period can contain two sub-periods: a post-injection and closure period and a post-closure period.

Collapse strength — the pressure that will cause a mechanical well component to collapse the casing.

Containment — prevention of leakage or migration of CO_2, brines, and affected fluids from an EOR or storage complex (aka. reservoir).

Corrective measure — any measure taken to correct material irregularities or to contain breaches in order to prevent or stop the release of CO_2 from a storage complex. Corrective measures are implemented after an irregularity has occurred to help prevent or minimize damage.

Design, construction, and operation — the (a) design and construction of surface and subsurface facilities such as distribution pipeline and injection sites, injection wells, and monitoring wells and other monitoring facilities; (b) development and implementation of a monitoring measurement and verification program; and (c) operation of facilities over the active injection phase of a storage project.

Elements of concern — valued elements or objectives for which risk is evaluated and managed.

Elevated pressure zone — a zone within a storage unit (aka. reservoir) where there is sufficient pressure to cause movement of formation fluids from the storage unit through a high permeable pathway into the biosphere or into an economic resource (oil & gas reservoir) above the storage complex.

Enhanced Oil Recovery (EOR) – Process to improve oil and gas recovery by injection of CO_2 and mixtures of CO_2 and other fluids to dislodge oil and gas from formation pore spaces, which allows the oil and gas to flow to producing wells.

Event — a material occurrence or change in a particular set of circumstances.

External wellbore mechanical integrity — the absence of significant fluid movement through vertical channels inside or adjacent to a wellbore.

Geological storage — The long-term isolation of CO_2 in subsurface geological formations. Injected CO_2 is trapped within the pore spaces within said formations. Recovery of CO_2 may occur for future oil and gas extraction operations such as water floods.

Geosphere — the solid earth below the ground surface and bottom of rivers and other bodies of water on land, and below the sea bottom offshore.

Hydraulic unit — a hydraulically connected geological unit (a) where pressure communication can be established on a human time-scale and measured by technical means; and (b) that is bounded by flow barriers (e.g., non-transmissive faults, salt domes, or beds and low-permeability geological formations) or by the wedging out or outcropping of the formation

Injection well regularity – the ability to actually inject CO_2 regularly at the desired rates necessary to store the delivered quantity or the quantity needed for CO_2 EOR or storage purposes

Leakage — The unintended upward movement (flow) of CO_2 or brine and CO_2 mixtures across primary geological seal(s) and/or well barriers and out of a storage complex. Depending on pathways and site characteristics, leakage can be limited to intervening secondary traps in the overlying sedimentary succession or can reach the biosphere and atmosphere.

Likelihood — a chance of something happening, expressed qualitatively or quantitatively and described using general terms or mathematically, e.g., by specifying a probability or frequency over a given period.

Long-term storage — storage of injected CO_2 streams in subsurface geological media for the time period necessary for CO_2 geological storage to be considered an effective and environmentally safe option. EOR stores CO_2 in pore space where oil and water have been displaced and removed via production wells.

Mechanical earth model (MEM) – is a repository of data – measurements and models – representing the mechanical properties of rocks and fractures as well as the stresses, pressures and temperatures acting on them at depth. Engineers and geoscientists use it to understand how rocks deform, and sometimes fail, in response to drilling, completion and production operations. Each data point in an MEM is referenced to its 3D spatial coordinates and time of sample collection.

Mechanical integrity test (MIT) — a pressure test performed on a well to confirm that it maintains internal and external mechanical integrity. MITs are a means of measuring the adequacy of the construction of an injection well and a way to detect problems within the well system. An MIT is the most common test used to identify leakage and loss of well integrity.

Migration — the lateral movement of brine (also referred to as saline water) within and outside a storage unit between the primary seals/confining formations.

Packer — a mechanical device set immediately above the injection zone that seals the outside of the tubing to the inside of the long-string casing, isolating an annular space.

Permeable formation — a geological formation that allows or permits the movement of fluids within the formation on a human time-scale that can be observed through pumping and/or injection.

Plume — three-dimensional extent within a storage unit of the injected CO_2 and displaced fluids such as oil, gas, and brine, and the associated pressure plume.

Post-closure period — the period after cessation of injection (including the post-injection closure period) that is marked by a transfer of responsibility and liability from the operator to the designated authority. If responsibility and liability are not transferred, the project will not enter the post-closure period and will remain in the post-injection and closure period until transfer occurs.

Primary seal — the low-permeability continuous geological unit (known in reservoir engineering as caprock and in hydrogeology as aquitard or aquiclude) that confines fluids within a storage unit immediately above or below it.

Project life cycle — the stages of a project, beginning with those necessary to initiate the project (including site screening, assessment, engineering, and permitting) and leading up to the start of injection, followed by operations until the cessation of injection, and culminating in the closure period, which can include a post-injection closure period and a post-closure period, if a transfer of responsibility and liability occurs.

Project operator (aka. operator) — the legal entity responsible for project organization, activities, and decision- making until a transfer of responsibility and liability to a designated authority (if such a transfer takes place).

Project stakeholder — an individual, group of individuals, company, or organization that believes its interests could be affected by a project and therefore wishes to take part in decisions about the project or to have its interests represented in discussions about such decisions. Stakeholders can include, e.g., employees, shareholders, community residents, suppliers, customers, non-governmental organizations, governments, regulators and other individuals or groups.

Protected groundwater — water that is defined as groundwater by legislation or a regulatory agency, is used for human consumption and/or agricultural and industrial purposes and is protected against contamination through legislation or regulations.

Note: *In Canada, protected groundwater is defined in each province or territory as water with a total dissolved solids (TDS) of less than a certain value (e.g., 4000 mg/L in Alberta). In the United States, the Environmental Protection Agency defines protected groundwater as groundwater with a TDS less than 10,000 mg/L of total dissolved solids.*

Risk — the effect of uncertainty on project objectives (e.g., on performance metrics for an element of concern) expressed in terms of a combination of the severity of consequences (negative impacts) of an event and the associated probability of its occurrence.

Risk analysis — a process for understanding the nature and level of risk.

Risk assessment — the overall process of risk identification, risk analysis, and risk evaluation.

Risk control — measures whose purpose is to reduce risk.

Risk evaluation — the process of comparing the results of a risk analysis with risk evaluation criteria to determine whether (a) the risk, its magnitude, or both are acceptable or tolerable; or (b) treatment will be required to reduce the risk.

Risk evaluation criteria — terms of reference against which the significance of risk is evaluated.

Risk identification — the process of finding, recognizing, and describing risks.

Risk management plan — a scheme specifying the approach, management components, and resources to be applied to the management of risks.

Risk owner — a person or entity with the accountability and authority to manage risk.

Risk scenario — a combination of a threat-event scenario (a chain of circumstances through which a threat can cause an event to occur) and possible event-consequence scenarios (a chain of circumstances through which the consequences of an event can have a negative impact on elements of concern).

Risk treatment — a process to modify risk through implementation of risk controls.

Secondary seals — low-permeability geological units (known in reservoir engineering as caprocks and in hydrogeology as aquitards or aquicludes) in the sedimentary succession above (i.e., shallower than) the primary seal. In the context of groundwater protection, these seals are located between the saline aquifer or hydrocarbon reservoir immediately overlying the primary seal and the base of the protected groundwater.

Secondary traps — saline aquifers and/or oil and gas reservoirs, located in the sedimentary succession between a CO_2 injection complex and the base of protected groundwater aquifers that will trap CO_2 in case of leakage from the EOR or storage unit.

Significant risk — a risk whose magnitude is reduced through implementation of appropriate risk treatment to maintain compliance with this Standard.

Site characterization, assessment, and selection — a detailed evaluation of one or more candidate sites for CO_2 injection identified in the screening and selection phase of a EOR or storage/disposal injection project to confirm and refine containment integrity, storage capacity, and injectivity estimates, and to provide basic data for initial predictive modelling of fluid flow, geochemical reactions, geomechanical effects, and risk assessment and monitoring measurement and verification program design.

Site closure — a point within a closure period when the operating site (e.g., injection facility) has met the specified requirements of the designated authority such that the long-term responsibility and liability can be transferred to the designated authority.

Site screening — the initial evaluation of the suitability of geologically storing CO_2 at the regional or sub-regional scale by identifying, assessing, and comparing candidate storage formations or sites on the basis of criteria for containment, capacity, and injectivity.

Spatial data — data that are associated with a geographical location such as a point, a linear feature, or an area, including all attributes and information that can be tagged to the location (e.g., sample test results, surveys, classifications, photos, and reports).

Storage complex — a subsurface system comprising a storage unit and primary seal(s) extending laterally to natural boundaries or to the defined limits of the effects of a brine injection/storage operation or operations. The subsurface storage system can also include secondary seals that offer additional containment potential.

Storage/Disposal project — a number of components for a CO_2 separation, injection, and storage or disposal operation that includes site selection and characterization, baseline data collection, permitting, design and construction of site facilities (site pipelines, well flowlines, pumps, etc.), well drilling, delivery of CO_2 to the disposal/storage site and CO_2 injection during the active injection phase, site closure (including well and facilities abandonment), and post-closure. It also includes monitoring during all project phases.

Storage site — an area on the ground surface, defined by the operator and/or regulatory agency, where brine separation, treatment, transfer, and injection facilities are developed and storage activities (including monitoring) take place.

Storage/Disposal unit — a geological unit into which CO_2 is injected (e.g. depleted oil or gas reservoir or deep saline aquifer).

Surface cap — a permanent seal placed over the top of a casing (cut off below grade) to prohibit fluid migration into an inactive well while also restricting access to the casing from the surface. A seal can be made using steel plate, cement, or some other means, singly or in combination.

Threat — an element that by itself or in combination has the potential to cause damage or produce another negative impact.

Transfer of responsibility — a transfer of all rights, responsibilities, and liabilities associated with a storage site to a designated authority. It is not clear at this time, whether the transfer can occur prior to a planned closure. It should be noted that the pore space in the U.S. is not owned by the Sovereign Head of State (as in Canada, Norway, U.K. etc.) and the pore space and mineral rights can be owned by an individual citizen, state or federal/tribal agency.

Transport network — a network of pipelines, flowlines, including associated pumping stations, for the transport of CO_2 from its source to an injection storage site and then pumping to injection wells in the oil and gas producing field or nearby field.

Water column — a vertical, continuous mass of water from the surface to the bottom sediments of a water body.

Well mechanical integrity (WMI) — the satisfactory mechanical condition of a well, such that engineered components maintain their original dimensions and functions, solid geological materials are kept out of the wellbore, and fluids including injected brine are prevented from uncontrolled flow into, out of, along, or across the wellbore, cement sheath, casing, tubing, and/or packers.

APPENDIX 2 - CO_2 ENHANCED OIL RECOVERY

A2.1 OVERVIEW AND THE CO_2 EOR PROCESS

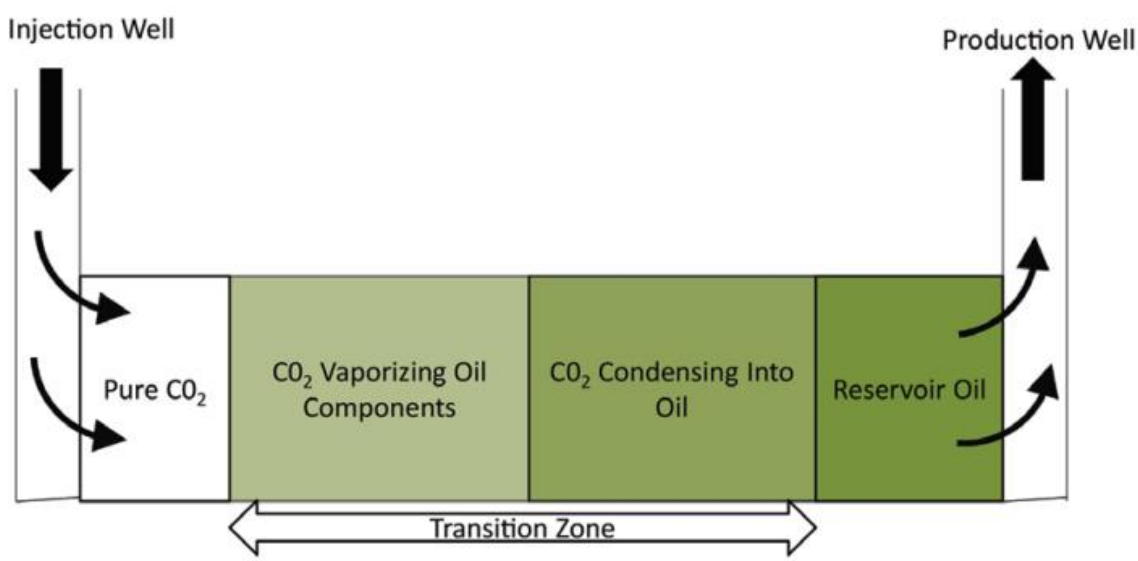
After discovery, an oilfield is initially developed and produced using primary recovery techniques in which natural reservoir energy – expansion of dissolved gases, change in rock volume, gravity, and aquifer influx – drive the hydrocarbon fluids from the reservoir to the wellbores as pressure declines with fluid (oil, water, or gas) production. During the secondary recovery phase, either water or natural gas is injected into the reservoir for re-pressurizing and/or pressure maintenance and to act as a water or gas drive to displace the oil. Normal practice is to inject the gas into the gas cap and water below the oil-water contact. The first two phases of primary and secondary recovery typically recover 30-40% of the original oil-in-place (OOIP), while tertiary enhanced oil recovery (EOR) can recover an additional 5-15% of the OOIP, with as high as 35-45% reported from some North Sea reservoirs. The total oil recovery at Occidental's Denver Unit in the Wasson oilfield in West Texas is reported to be 68.8% of the OOIP (see Section 8.4 - Case Study # 4).

The goal of enhanced oil recovery (EOR) or tertiary recovery processes is to recover at least a part of the remaining oil-in-place (residual oil). The EOR processes can be divided into three major categories: (1) chemical, (2) thermal, and, (3) miscible. Thermal processes have been used extensively for displacement of heavy oils, whereas chemical and miscible displacement processes have been employed for the recovery of light oils. Because of its special properties, CO_2 improves oil recovery by lowering interfacial tension, swelling the oil, reducing oil viscosity, and by mobilizing the lighter components of the oil. Under the right conditions of pressure, temperature and reservoir oil composition, CO_2 can create a miscible front, which moves as a single liquid phase and efficiently displaces reservoir oil to the producing wells. The CO_2 miscibility can be achieved at pressures as low as 1500 psi (10.3 Mpa) at normal reservoir temperatures. The presence of impurities such as nitrogen and methane, increase the miscibility pressure, whereas impurities such as propane and H_2S decrease it. Ultimate recovery values above 60% of OOIP are very rare with EOR techniques, although Shell has predicted a recovery of 64% of OOIP with CO_2 EOR in its offshore Draugen field in the Norwegian Sea (Petroleum Resources on the Norwegian Continental Shelf, NPD 2011).

The CO_2 EOR process recovers oil that remains in the reservoir after primary and secondary recovery by contacting and mobilizing the residual oil by improving the volumetric and sweep efficiencies. The injected CO_2 may become miscible or remain immiscible with oil, depending on reservoir pressure, temperature and oil properties. The miscible CO_2 EOR process typically achieves higher recoveries than the immiscible process, and is therefore, is the preferred option. The pressure at which miscibility occurs is called the minimum miscibility pressure (MMP).

When the reservoir pressure is above the MMP, miscibility between CO_2 and reservoir oil is achieved with time as displacement occurs in what is classified as multiple-contact or dynamic miscibility. The intermediate and higher molecular weight hydrocarbons from the reservoir oil vaporize into the CO_2 (vaporization gas-drive process) and part of the injected CO_2 dissolves into the oil (condensation gas-drive process). This mass transfer between the oil and CO_2 allows the two phases to become completely miscible without any interface and helps to develop a transition zone that is miscible with oil in the front and with CO_2 in the back (Figure A2-1).

Figure A2-1 - The CO_2 miscible process showing the transition zone between the injection and production well



As a result of the low viscosity of solvents, viscous fingering is a frequent problem. Also, override by the less dense phase leads to poor sweep efficiency. To mitigate these problems and reduce the solvent requirements, a water-alternating-gas (WAG) process is frequently used in CO_2 flooding to increase sweep efficiency and decrease the need for expensive solvents. Among the operating problems found in CO_2 flooding include: corrosion, scale deposition, and precipitation of heavy ends from the crude.

A2.2 INJECTION SYSTEMS FOR CO_2 EOR FACILITIES

Because most CO_2 floods use the WAG process, there are two injection systems: water and CO_2. Most CO_2 floods are implemented after some period of water-flooding, so a system of water injection is already in place. Plans for the water side of the CO_2 flood should begin with an analysis of these facilities to see if any can or should be used. Critical factors in determining whether they can be used or modified include: maximum pump discharge pressure, desired injection rates, pressure rating of the flowlines, and maintenance and operating history of the facilities.

A2.3 WATER INJECTION SYSTEMS

Re-pressurization

Sometimes the reservoir pressure is below the thermodynamic minimum miscibility pressure (MMP) for CO_2, and if miscible CO_2 displacement is desired, the reservoir pressure should be raised above the thermodynamic MMP before injecting CO_2. The three general methods for re-pressurization are: (1) to increase the injection rate until it is above the total fluid production rate, (2) to restrict production, and (3) to both increase the injection rate and decrease the production rate. A technique using Hearn and Hall plots to accelerate reservoir pressure growth was successfully used in a Slaughter field CO_2 flood (Jarrell et al., 1991).

Water Supply: Compatibility and Corrosion

Since the goal is to inject more fluid than is produced, re-pressurization may require an additional supply of water. The makeup water must be analyzed for compatibility with the produced fluid and for corrosion potential.

Compatibility with produced water is an important factor in selecting the makeup water supply. For instance, mixing a water high in calcium carbonate with a water high in sulfates can cause calcium sulfate scale. In addition to physical testing, scaling tendencies across the range of pressures and temperatures to be encountered in the flood operation should also be evaluated. The corrosion and scaling tendency of the makeup water can affect the selection of piping materials. In some instances, it may be more economical to use corrosion resistant materials (e.g. HDPE or fiberglass) than chemicals.

Regardless of how you manage oxygen in the makeup water piping, oxygen-accelerated corrosion must be addressed before mixing the makeup water with the produced water for reinjection. The most common technique is to use an oxygen scavenger, although these chemicals tend to be more toxic (an important factor when surface discharge is a possibility) and expensive. Other alternatives include use of: corrosion inhibitors, move the oxygen-scavenger further downstream and minimize effects of discharge, find another source of makeup water, or live with higher corrosion rates.

Although the primary need for makeup water occurs during re-pressurization, other needs may include at times of off-structure fluid losses, for fresh water dilution, for fire systems, cooling systems, and as a potable water supply.

A2.4 CO_2 INJECTION/DISTRIBUTION SYSTEMS

The CO_2 distribution system delivers CO_2 to individual injection wells from the pipeline supply and the gas processing facility. This system is independent and separate from the water injection system and has its own piping, valves, measurement, and control facilities.

Piping Arrangement and Materials

Components of a CO_2 distribution system include trunk-lines, laterals, and individual well injection flowlines. Trunk-lines distribute CO_2 from the source (e.g., pipeline or gas processing facility) to and through the field. Laterals branch off to deliver CO_2 to several injection wells. Injection flowlines branch off the laterals to deliver CO_2 to each well.

A common material for CO_2 piping is carbon steel, which is excellent as long as free water is not present; that is, as long as the CO_2 has been dehydrated to prevent free water from condensing out of the injection stream when pressure and temperature drop en-route to injection wells. Other materials used for the CO_2 distribution system are stainless steel and fiberglass.

A significant disadvantage of carbon steel piping is that it is rated only to -20°F/-28.9°C), which can be insufficient for cold climates. The temperature of pipe can also drop significantly below ambient temperature when CO_2 is throttled through a valve or if a line leaks. Therefore, carbon steel needs to be ordered to a cold temperature specification if operation below – 20^0 F (- 28.9^0 C) is anticipated (ASTM Spec. A333/A333M-88a) (Jarrell et al, 2002).

Challenges of using fiberglass pipe include: inability to withstand high pressures, limited applicability in cold-temperature service, and its pipe length may change significantly as temperature changes. Therefore, manufacturer recommendations must be obtained prior to use of fiberglass piping.

Handling H_2S

Hydrogen sulfide often is present in the CO_2 reinjection stream but is only problematic if free water is present because the combination of free water and H_2S can cause sulfide stress cracking. Free water can originate from insufficient dehydration, excess pressure or temperature drop, or plant upsets. The WAG process itself creates another source of free water in the CO_2 distribution system: If the supply pressure drops while the injection well is on a CO_2 cycle (injecting CO_2), the injection well has the potential to backflow water from the formation if the check valve fails to hold (onshore operations).

The CO_2 distribution and gas processing systems should be designed to prevent free water from occurring and for sour environment service including H_2S removal, dehydration and mechanisms to prevent backflow conditions. If downstream components are not designed for sour service, then system integrity must be enhanced with automated controls, alarms, and even backup systems that can prevent sour conditions from occurring.

Another alternative to handle the combination of water and CO_2 is the use of different materials and welding procedures. Carbon steel can still be used as long as sulfide stress cracking and corrosion are adequately addressed.

Blowdown Capability

To perform maintenance on the CO_2 distribution system, one must be able to depressurize the system safely and effectively. This is done through a blowdown station, which is simply a vertical vent pipe that has an isolation (blowdown) valve welded to the main distribution line. To depressurize the system, the blowdown valve is opened, and CO_2 vents to the atmosphere.

The extreme noise, large temperature drop, and presence of CO_2 during blowdown operations can cause safety and health problems for both operating personnel and the public. Pipes and valves must be sized to minimize these problems and to prevent the formation of hydrates that result from a large pressure drop. Hydrates can be prevented by large, nonrestrictive valves or by adding heat (Jarrell et al, 2002).

Valves in CO_2 distribution systems in US onshore are usually carbon steel. The valves and the bolts for holding it in place must be rated for cold temperature service – ASTM Spec. A320/A320M-00a.

Metering and Control

The relatively high cost of CO_2 makes metering and control an important issue. The level of automation can range from none, to monitoring, to data collection and storage, to full control.

Pressure Control - CO_2 injection can be controlled on rate or pressure or both. Pressure control, using a pressure gauge or transducer and choke is the most common, with both manual and automated systems in use.

Rate Control – Rate control requires some type of measurement device and a choke, and it also can be manual or automatic. Most common measurement devices are turbine meters and orifice meters. Because orifice meters are more accurate than turbine meters, they are commonly used for custody transfer. Custody transfer measurement provides quantity and quality (Q&Q) information used for physical and fiscal documentation of a change in ownership and/or a change in responsibility for commodities, including crude oil, natural gas, and CO_2. In general, orifice meters are more expensive to install but easier and less expensive to maintain than turbine meters. Orifice meters require only periodic inspections of the orifice plate (and replacement of the elastomer O-rings), while turbine meters tend to wear out bearings and turbine blades more frequently. The selection comes down to a trade-off between capital and operating costs.

Control Devices

In most cases, chokes or ball valves are used to adjust flow rate to meet the rate or pressure set-point. A choke differs from other valves in that it is designed to operate with large pressure drops and its construction materials are highly resistant to erosion and cavitation. Typical chokes have a carbon steel body with internals of carbon steel, while the disks that restrict flow are usually ceramic.

Ball valves can be used when pressure drops are lower and should be sized to operate within a 20 to 80% open range to provide a smoother and more consistent control of the injection pressure and/or rate.

Safety and Environment

Automatic Control Systems

Automated control systems are commonly used to continuously control and monitor CO_2 injection operations to assure both their performance and mechanical integrity. These systems provide real-time information from which immediate corrective action can be taken, if required. The principle components of these control systems include:

1. *Meter(s)*
2. *Control valve(s), and*

3. Pressure sensors for both the tubing and the casing head.

Additionally, check valves, isolation valves, blinds and bleeds/nipples are incorporated into the surface piping configuration to prevent backflow and facilitate servicing.

Flow Isolation

While CO_2 EOR operations require CO_2 and water flows, they occur sequentially rather than simultaneously for extended periods of time. As an additional safety practice, operators insert a blind flange in the line of the non-flowing phase to assure its complete isolation. This procedure assures that in the event a valve (check or isolation) does not seat properly, no back flow can occur which could induce corrosion and over-pressurization.

A2.5 U.S. ONSHORE CO_2 EOR

In the United States, the oil and gas industry operates over 13,000 CO_2 EOR wells and has made significant improvements in the design and operating practices of CO_2 EOR wells over the past 40 years.

The Permian Basin is one of America's premier energy provinces and covers more than 75,000 square miles/194,250 square km (250 miles/402 km wide and 300 miles/483 km long) in southeastern New Mexico and much of West Texas. Various producing formations such as the Yates, San Andres, Clear Fork, Spraberry, Wolfcamp, Yeso, Bone Spring, Avalon, Canyon, Morrow, Devonian and Ellenburger are all part of the Permian Basin, with oil and natural gas production depths ranging from a few hundred feet to 5 miles/8.1 km below the surface. Other areas within the greater Permian Basin include the Delaware Basin and the Midland Basin. The Delaware Basin includes significant development in the Wolfcamp and Bone Spring, together known as the Wolfbone, while the Midland Basin includes significant development in the Spraberry and Wolfcamp, known together as the Wolfberry. Recent increased use of EOR has resulted in a substantial impact on U.S. oil production.

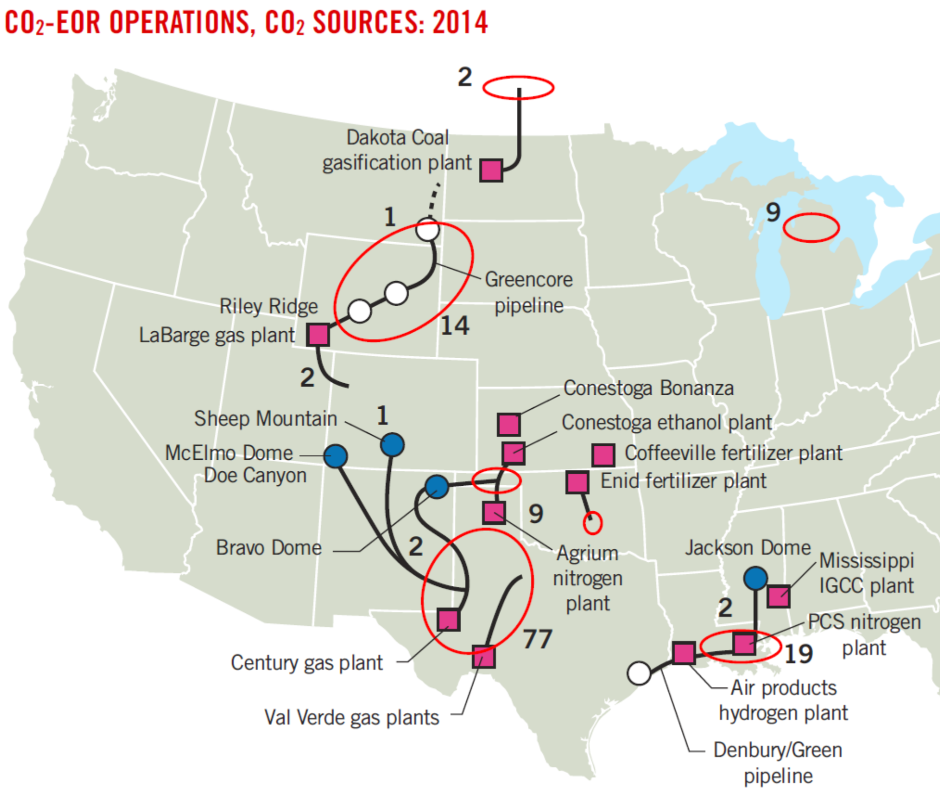
The first field-wide application of CO_2 EOR took place in 1972 at the SACROC (Scurry Area Canyon Reef Operators Committee) Unit of the Kelly-Snyder Field in Scurry

County, West Texas and remains today the world's largest miscible flooding project. The CO_2 was supplied from the Val Verde Gas Plant at 2350 psi (16.2 MPa) via a 200-mile (322 km) pipeline.

Development of large natural sources of CO_2 in Colorado (McElmo Dome/Doe Canyon) and New Mexico (Bravo Dome with 97% CO_2) plus construction of high-volume CO_2 pipelines enabled CO_2 EOR to achieve its first burst of growth in the Permian Basin starting in the 1980s. Subsequent development of natural CO_2 supplies at Jackson Dome, Mississippi, and the capture of vented CO_2 at the massive LaBarge natural gas processing plant in western Wyoming led to the second round of CO_2 EOR growth at the turn of the century in the Gulf Coast and the Rocky Mountains. Based on these two growth phases, the industry now injects 3.5 billion cubic feet per day - bcfd (68 million tonnes/year [tpy]) of natural and industrial CO_2 to produce 300,000 barrels per day (b/d) of oil via EOR (38% of U.S. EOR output) with a steady increase over the past 30 years (Kuuskra et al, Oil and Gas Journal, April 7, 2014). Globally, the U.S. has the highest number of active CO_2 EOR projects and ranks first in terms of total oil production from CO_2 EOR, accounting for ~ 80% of oil sourced globally from CO_2 injection.

Figure A2-2 shows the locations of the currently active CO_2 EOR projects with much of the activity in West Texas (77 projects), followed by Mississippi (19 projects), and Wyoming (14 projects). Figure A2-2 also shows the location of existing CO_2 supply sources, with an increasing number of industrial sources supplying CO_2 to the EOR industry (although the majority is still supplied from natural CO_2 sources). The CO_2 is transported within a 7,200 km/4,475 mile network of pipelines operated either as a common carrier (which is generally required to serve all customers at reasonable rates), or as a private carrier which is not subject to common carrier rights and responsibilities (that is a dedicated source-sink link owned by a single operator). The U.S. CO_2 supply and pipeline network has been developed by both oil producers for their own integrated CO_2 EOR projects and by third parties that deliver CO_2 to oil producers (Raven et al, 2016, Kuuskra et al, 2014). Table A2-1 provides a partial listing of recently announced industrial plants planning to capture CO_2 emissions for sale to the EOR market.

Figure A2-2 - CO_2 EOR Operations, CO_2 Sources: 2014 (O&G Journal, 2014)



Oil production, 2014	
CO_2 –EOR projects	136
Oil production, 1,000 b/d	300
CO_2 supplies, 2014	
Number of sources	17
• Natural	5
• Industrial	12
CO_2 supply, MMcfd	3.5
• Natural	2.8
• Industrial	0.7

136 Number of CO_2-EOR projects

Natural CO_2 source

Industrial CO_2 source

CO_2 pipeline

CO_2 proposed pipeline

Source: Advanced Resources International Inc. based on OGJ EOR/Heavy Oil Survey 2014 and other sources

Table A2-1 - Recently Announced Industrial Sources of CO_2 in U.S

Region	Project Name	Company	State	Status	Year Online
Gulf Coast	Port Arthur Kemper County IGCC Nitrogen plant Ammonia plant W.A. Parish Sasol GTL Lake Charles Chemical plant	Air Products Southern Co. PCS Nitrogen Not available NRG Energy Sasol Leucadia Energy Not available	LA MS LA LA TX LA LA LA	Online" Expected Online Expected Expected Expected Expected Expected	2013 2014 2013 2016 2016 2018 2018 2020
Rockies	Lost Cabin Medicine Bow Riley Ridge Wyoming UCG Quintana South Heart	ConocoPhillips DRKW Denbury Linc Energy Great Northern Power	WY WY WY WY ND	Online Expected Expected Expected Expected	2013 2016 2017 2017 2017
Midcontinent	Bonanza Coffeyville	Conestoga CVR Energy	KS KS	Online Online	2013 2013
Permian Basin	Century plant expansion Texas Clean Energy	Sand Ridge/Occidental Summit Energy	TX TX	Expected Expected	2015 2016

Projected CO_2 EOR production – is estimated to increase to 638,000 b/d (101,000m^3/d) in 2020 from 300,000 b/d (48,000 m^3/d) in 2014 (Figure A2-4) and this estimate is derived from several sources namely: existing CO_2 floods, planned CO_2 EOR floods, and potential CO_2 EOR floods. Figure A2-4 also shows the projected CO_2 EOR production by region in the U.S. by year 2020.

Figure A2-3 - Projected CO_2 EOR Operations by 2020

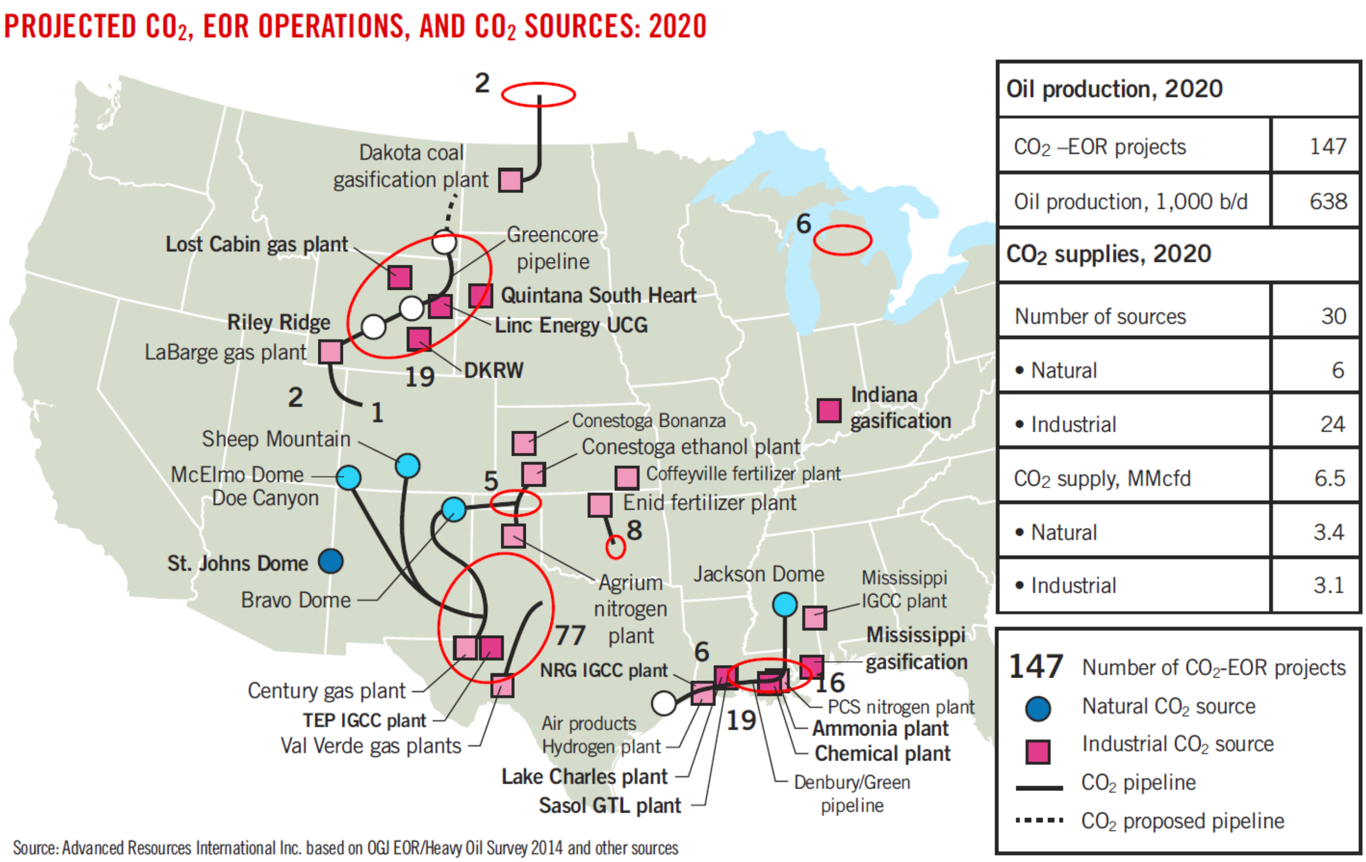
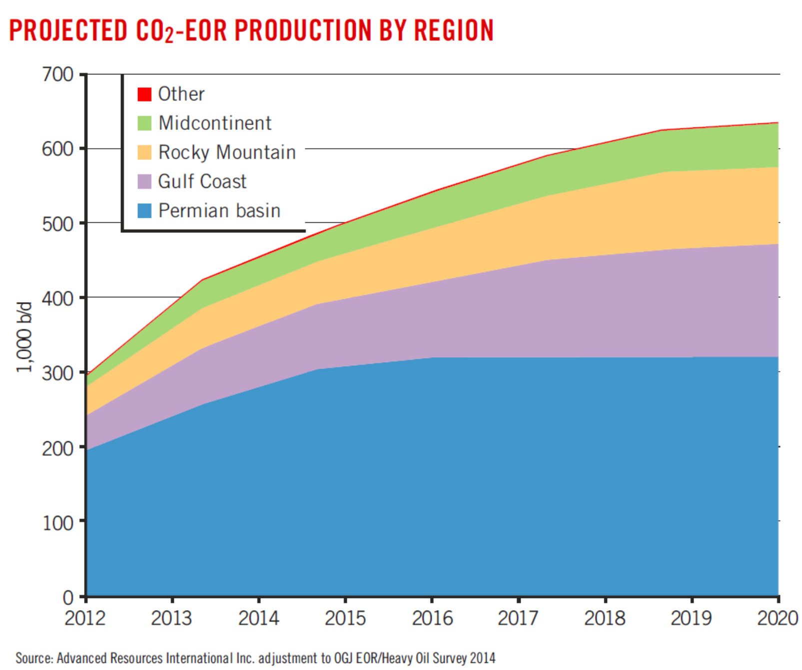


Figure A2-4 - Projected CO_2 EOR Production by Region in 2020



The pursuit of residual-oil-zone (ROZ) resources indicates an increase in CO_2 demand and oil production in the Permian Basin. Residual-oil-zones, called ROZs, are areas of immobile oil found below the oil-water contact of a reservoir and are similar to reservoirs in the mature stage of waterflooding. In the case of ROZs, the reservoir has essentially been waterflooded by nature and requires EOR technologies, such as CO_2 flooding, to produce the residual oil. The U.S. Department of Energy (DOE) estimated in 2006 that ROZs could contain 100 billion barrels out of 1.124 trillion barrels of technically recoverable oil in place in U.S. reservoirs (OGJ, 2012). Current ROZ projects include: Occidental (Oxy's) Denver Unit and other units in the Wasson field; Hess's project in Seminole (San Andres) oil field; and Kinder Morgan's major project in the Permian Basin.

A2.5.1 International Onshore CO_2 EOR

Use of CO_2 for EOR has been slow outside of the U.S. perhaps due to the factors that are unique to the U.S. on a regional basis, as has been discussed earlier. There are some 140 CO_2 EOR projects worldwide that contribute ~ 0.35% to global daily oil production, or about 300,000 b/d (48,000 m^3/d). A listing of the active CO_2 EOR projects outside the U.S. is given in Table A2-2.

Table A2-2 - Active CO_2 EOR Projects outside the U.S. (O&G Journal, April 2014)

Country	Type/Operator	Field	Province	Start Date	Area (acres)	Number of Wells P	Number of Wells I	Pay Zone	Formation	Porosity (%)
Canada	Apache Canada	Midale	Sask.		30,483	43	5	Marly and Vuggy	Dolo./LS	16.3
Canada	Devon Canada	Swan Hills	Alta.			5	1	Beaverhill Lake	LS	8.5
Canada	Cenovus	Weyburn Unit	Sask.		17,280	320	170	Midale	LS/Dolo	15
Canada	Pengrowth Corp.	Judy Creek	Alta.		80	4	1	Swan Hills	LS	12
Canada	Penn West Energy Trust	Joffre	Alta.		6,625	33	15	Viking	S	13
Canada	Penn West Energy Trust	Pembina	Alta.		80	6	2	Cardium	S	16
Brazil	Petrobras/CO2 Immiscible	Buracica	Bahia	1991	1,670		7	Sergi	S	22
Brazil	Petrobras/CO2 Miscible	Rio Pojuca	Bahia	1999			1	Agua Grande	S	
Brazil	Petrobras/CO2 Miscible	Miranga	Bahia			27	10	Catu-1	S	20
Trinidad	Petrotrin	Area 2102	Forest Reserve		58	6	2	Forest Sands	S	32
Trinidad	Petrotrin	Area 2121	Forest Reserve		29	2	2	Forest Sands	S	30
Trinidad	Petrotrin	Area 2124	Forest Reserve		184	3	1	Forest Sands	S	31
Trinidad	Petrotrin	EOR 34-Cyclic	Forest Reserve		NA	11		Forest/MLE	S	29
Trinidad	Petrotrin	Oropouche	Forest Reserve		175	4	3	Retrench	S	30
Turkey	TPAO	Bati Raman	Batman		12,890	212	69	Garzan	LS	18

Table A2-2 (continued)

Permeability (md)	Depth (ft)	Gravity (deg, API)	Oil (cp)	Oil (deg F)	Previous Prod.	Satur. % at Start	Satur. % at End	Project Matur	Total Prod. (b/d)	Enhhanced Prod. (b/d)	Project Eval.	Profit	Project Scope
7.5	4,600	30	3	149	WF	45		JS	5,900		Prom.	Yes	FW
54	8,300	41	0.4	225		30	5	JS					P
10	4,655	28	3	140	WF	45	30	JS	22,000	11,000	Prom.		LW,Exp.L
50	8,200	41.5	0.65	206	HC			JS			TETT		P
500	4,900	42	1.14	133	WF	38	23	HF	700	700	Succ.		P
20	5,300	41	1	128	WF			JS			TETT		P
	1,970	35	10.5	120	Prim./WF			NC			Succ.	Yes	RW
	5,900	36	2	183	Prim.			HF			TETT		P
112	4,000	39.4	1.2	156	WF			JS			TETT		P
175	3,000	19	16	120	Prim.	56		HF	43	43	Succ.	Yes	Exp.L
150	2,600	17	32	120	Prim.	60		HF			Prom.		Exp. L
300	4,200	25	6	130	WF	44		TS	78	78	Prom.		Exp. L
150	2,025	17	11-145	120	Prim.			HF	160	160	Prom.		
36	2,400	29	5	120	Prim.	53	48	HF	32	32	Prom.		P
58	4,265	13	592	129		78		NC	7,000	7,000	Succ.	Yes	FW

Although it is difficult to reach the MMP in heavy oil reservoirs, an important mechanism of CO_2 methods in heavy oil is viscosity reduction along with swelling of oil. Miller et al, 1981 indicated that one barrel of heavy oil (17^0 API) can dissolve more than 700 standard cubic feet (scf) of CO_2 and has a volume increase of between 10-30% under certain pressures and temperatures. Another factor that was neglected before - solution gas drive has been found to be important in recent years, due to a phenomenon called "foamy oil". When pressure decline occurs in the oil-solution gas phase, little gas bubbles are generated from the oil, and trapped and dispersed in the oil phase. The gas-liquid two-phase flow is known as foamy oil. The existence of foamy oil flow is believed to be an influential factor in stimulating high recovery in many heavy oil reservoirs in Canada and Venezuela and is being investigated for application in CO_2 EOR methods in China (Huang et al, 2017).

<u>Bati Raman Field, Turkey</u>

The onshore Bati Raman field in southeast Turkey was discovered in 1961 and is operated by the Turkish Petroleum Company (TP). Production is from the Garzan limestone –a heterogeneous carbonate from the Cretaceous period. The heavy crude has 11 degree API gravity (0.99 SG), high viscosity and low solution-gas content. The OOIP was estimated to be 1.85 billion bbl (300 million m^3). During the primary production period between 1961 to 1986, reservoir pressure declined from 1,800 psi (12 MPa) to as low as 400 psi (2.8 MPa) in some parts of the field, and crude production dropped from 9,000 bbl/d (1,400 m^3/d) in 1969 to 1,600 bbl/d (250 m^3/d) in 1986. Estimated primary recovery was less than 2%.

The operator chose immiscible CO_2 flooding primarily due to the proximity of the Dodan gas field. The Dodan gas field is 55 miles (89 km) from the Bati Raman field and produces gas that is mostly CO_2 and has 3,000 to 4,000 ppm H_2S. The wellhead pressure at the Dodan field is about 1,050 psi (7.2 MPa). After treatment, the CO_2 from the Dodan field is sent to the Bati Raman field via pipeline.

TP conducted a pilot test with 17 injection wells with the original plan of cyclic injection. Based on the pilot test results, the operator decided to opt for CO_2 flooding. In 2012, the CO_2 project was 25 years old, far beyond initial project plans, with more than 6% recovery of the OOIP, far higher than the original 2% recovered during the primary phase. Primary recovery was 32 million bbl (5.1 million m^3) while total field production (from primary, secondary and EOR) was 114 million bbl (18 million m^3) as of the end of 2014 (Oilfield Review, 2015).

Onshore Brazil

Petrobras has proposed a CO_2 continuous injection project in an onshore oilfield Miranga in Reconcavo Basin, northeast of Brazil. Miranga is comprised of a turtle-back incline with an important net of axial faults compartmentalizing the field in several structural blocks.

The stratigraphic layout of Miranga consists of successive porous layers intercalated by thin shale layers. Previous to injection, the field has undergone depletion that modified the original stress state. Because of the differences in pore pressure along the faults, extensions of the faults may be reactivated, allowing intercommunication between reservoirs. The sensitivity analyses indicate that the fault reactivation process is controlled mainly by the initial state of stresses (vertical and minimum horizontal stresses) and by the fault cohesion and fault friction angle, although the latter data is difficult to obtain in the field. It is recommended that mini-frac tests be conducted to determine the magnitude of the in-situ stress state during injection. The simulation studies have also indicated that fault reactivation may occur and therefore well pressures in all reservoir layers should be monitored during CO_2 injection along with permanent microseismic monitoring to detect any possible intercommunication through existing faults. Therefore the establishment of the maximum injection pressure is essential for proper evaluation of the injection system capacity in CO_2 injection projects (Mendes et al, 2010). Although, adverse conditions caused by increased pressure is not expected to be an issue in most conventional onshore reservoirs, greater attention will need to be paid for CO_2 injection projects in areas such as deep water (pre-salt and sub-salt) offshore.

A2.6 OFFSHORE CO_2 EOR

Offshore use of CO_2 for enhanced oil recovery is in its infancy. Over the last 25 years a small number of offshore saline aquifers and oil and gas reservoirs have successfully used technologies developed through the last 60 years of onshore CO_2 EOR experience. The absence of an economical supply of CO_2 has hampered efforts to increase CO_2 EOR applications offshore, however, as carbon capture from nearby electric power plants and other large, stationary sources of CO_2 emissions becomes more common, CO_2 EOR hydrocarbon production from offshore depleted/marginal reservoirs is expected to increase.

In shallow water oil fields in a mature stage, with a strong natural water drive, high original oil in place (OOIP) recoveries can be achieved with other EOR techniques that have higher sweep and displacement efficiencies, leaving a much smaller residual oil target for CO_2 EOR. In deep water reservoirs, with higher cost wells and more complex facilities, higher oil recoveries are also required to make CO_2 EOR economically feasible. However, in contrast with shallow water mature reservoirs, the primary/secondary oil recovery efficiencies in deep water fields are much lower, providing a larger residual oil target using CO_2 EOR.

CCS programs with offshore storage to abate emissions from power generation or associated gas may become a reality; especially after the COP21 and Major Oil companies asking for a carbon policy to be applied worldwide.

The success of CO_2 EOR in onshore fields in the last 60 years, has led to increased interest by operators for CO_2 EOR in offshore fields. The international pursuit of offshore EOR is somewhat active, as shown by the following active or planned CO_2 EOR projects:

1. *Offshore Brazil, Pre-Salt Layer (Lula Field)*
2. *North Sea*
3. *Offshore Abu Dhabi*
4. *Offshore Vietnam, Rang Dong Oil Field (only offshore application using anthropogenic CO_2)*
5. *Offshore Malaysia, Dulang Oil Field*

CO_2 EOR Offshore Brazil – Lula Pre-Salt Project

This has been discussed in greater detail in Section 8.1 Case Study # 1

CO_2 EOR North Sea

A number of CO_2 EOR projects have been considered for the North Sea, transporting the CO_2 from onshore power plants to offshore oilfields, including:

- *Draugen and Heidrun Oil Fields – In 2006, Shell and Statoil announced plans for capture of CO_2 from onshore power generation and transport and injection of the CO_2 into two Norwegian sector offshore oil fields.*
- *After completing the technical study, the Operator determined that although the project is technically feasible it would not be commercially feasible due to these factors: (1) only modest increase in oil recovery, (2) need to retrofit existing production wells, (3) need to drill additional six subsea wells to target the flanks of the reservoir, and (4) costs of building a CO_2 pipeline.*
- *Don Valley Project – This project involved capturing CO_2 from the Don Valley IGCC power plant and transporting the CO_2 300 km (186 miles) offshore to improve oil recovery and store CO_2 in two mature oil fields in the Central North Sea. Two options studied were: potential use of oilfields in central North Sea for EOR and deep saline aquifer storage in southern North Sea. The project is pending economic feasibility without government funding.*
- *Miller Oil Field – BP had planned to capture CO_2 from the Peterhead gas fired power station, and storing the CO_2 with CO_2 EOR in the Miller offshore oil field. Project failed to receive government support and the Miller field is now abandoned.*

- *Danish Oil Fields – Maersk Oil submitted a plan to EU to capture the CO_2 from an oil refinery and transport the CO_2 by ship, to oilfields in the Danish sector of the North Sea. This project is currently on hold.*
- *Tees Valley – Progressive Energy submitted a proposal to the EU for construction of a new IGCC power station with pipeline transportation of the captured CO_2 to Central North Sea oilfields for CO_2 EOR. This project is also currently on hold.*

CO_2 EOR Offshore Abu Dhabi

The first offshore CO_2 EOR pilot project in the Middle East is planned (2016) for an offshore carbonate reservoir in Abu Dhabi by Abu Dhabi Marine Operating Company and JOGMEC/Japan. The selected reservoir has 40 years of peripheral seawater injection history and the pilot design is influenced by existing peripheral pressure gradient, and is located down-dip in the field that covers approximately 80 acres (324,000 m^2). The pilot location has been selected based on geology, reservoir quality, maturity to waterflood and surface facility constraints and a comprehensive surveillance plan, including one to two observer wells has been developed. The pilot design will minimize current ongoing secondary production and impact on surface facilities, and develop mitigation strategies for various challenges such as asphaltene, scaling, corrosion, impact on existing carbon steel well completion materials, cements etc. associated with CO_2 injection (Kumar et al, 2016).

CO_2 EOR Offshore Vietnam

In 2007, a Joint Venture with Vietnam Oil and Gas Group (PetroVietnam), Japan Vietnam Petroleum Company (JVPC), and Japan Oil Gas and Metals National Corporation (JOGMEC) completed a feasibility study that indicated that CO_2 injection into the oilfields in the South China Sea would increase oil recovery by 6.4% of OOIP. A pilot study was also conducted in 2011 in the Rang Dong oil field, located about 135 miles/217 km southeast of Vung Tau, Vietnam. The field has been producing oil since 1998 from two major reservoirs: fractured basement granite (BM) reservoir and Lower Miocene (LM) sandstone reservoir. A pilot CO_2 Huff-n-Puff test was conducted in Block 15-2 of the Cuu Long Basin and confirmed the objectives – adequate CO_2 injectivity and increased oil production. CO_2 Huff-n-Puff is basically a well stimulation technique in one well and comprises of three stages: (1) inject CO_2 into a single producing well, (2) shut-in the well to allow CO_2 to soak and dissolve, and (3) produce the well back. The CO_2 was trucked by road to Vung Tau from a fertilizer plant near Hanoi, and then transported by ship to the Rang Dong oil field. This was the first CO_2 EOR application in Southeast Asia (Giang Tha Ha et al, 2012 and Murai et al, 2016). To monitor changes in reservoir fluid saturation, cased hole pulsed neutron saturation logging was also conducted (Konishi et al, 2013).

CO_2 EOR Offshore Malaysia

Starting in 2002, Petronas initiated a 4-year CO_2 EOR pilot in the Dulang oil field, located 130 km/81 miles offshore from Terengganu, eastern Malaysia in 250 feet/76 m of water. The offshore oil field is one of Malaysia's largest with 1.1 billion barrels (175 million m^3) of OOIP, but with a high CO_2 concentration (>50%) in the produced gas. The company conducted an immiscible-WAG pilot test over a 4-year period and confirmed that the IWAG process was operationally manageable and would lead to increased oil recovery. The project is yet to be implemented.

A2.6.1 CO_2 EOR Offshore Challenges

Current challenges for offshore CO_2 EOR projects include the project's higher development costs, existing offshore facility limitations (weight, space, power etc.), the lack of sufficient and economical CO_2 supplies (except where CO_2 concentration is high in the associated gas, as in Lula), fewer existing wells that are widely spaced, and competition from other technologies (including other EOR methods). The prognosis is better when successful secondary recovery methods have been applied through water and natural gas injection. Nonetheless, in an environment of ageing oil fields and few new major discoveries, the prospect of additional incremental recovery from existing fields is an attractive proposition, while high oil prices will also help to ensure that CO_2 EOR projects continue to be established throughout the world. Additionally, the market for CO_2 EOR projects may shift as jurisdictions further legislate against, or provide additional incentives for the sequestration of, greenhouse gases. Depending on the attributes of the particular oil reservoir, CO_2 EOR projects can serve the dual function of boosting oil production while capturing CO_2 underground (Raven et al, 2016).

CO_2 capture from flue gas sources with current technology is CAPEX and energy intensive, so that the cost of CO_2 abatement with CCS is high. Capturing CO_2 from industrial sources for use in EOR projects can maximize hydrocarbon recovery and help provide a bridge to a lower carbon emissions future. The offshore tankering of CO_2 is an interesting concept (Jenvey, 2010) for delivery of CO_2 from land-based sources to offshore fields. Tanker ships that deliver LNG to ports might carry CO_2 supplies on their return voyages to economically supply EOR projects (Sweatman, 2012).

Goodyear et al (2011) have described the challenges in bringing CO_2 EOR offshore as compared to working onshore. They are summarized below:

Safety

Onshore CO_2 EOR operations benefit from separation of equipment over distance, while offshore CO_2 EOR operations do not have this option. Resulting new HSE challenges that are introduced include:

- *Inventory; operational risks of working with large volumes of dense phase CO_2 (low temperatures and loss of visibility during CO_2 release and impact of release on third party population)*
- *Pressure: potentially very high injection/pipeline pressures for dense phase CO_2 [(generally maximum allowable operating pressures are between 1300 to 3000 psi (90 to 206 bar)]*
- *Confined spaces in offshore modules*
- *Re-injection gas mixtures, potentially containing hydrocarbons and H_2S*
- *Emergency response – detection, mitigation and evacuation*

During a significant release event, the heavier than air CO_2 will disperse under gravity to the sea surface, rather than rise as in the case of a conventional hydrocarbon release. This may impact stand-by vessels, since CO_2 concentrations at sea level may reach levels (2 to 5%) affecting vessel crews, potential diesel engine stall and loss of vessel control. Well interventions on wells will require special procedures as compared to hydrocarbon operations. When these differences and risks are recognized and addressed appropriately, then offshore CCS and CO_2 EOR projects can be designed and operated safely.

<u>*Facilities and Wells*</u>

The facility challenges for offshore CO_2 injection include:

- *The large fluid separation and gas compression capacity needed to process the high water production and the back produced CO_2 from the reservoir. This results in a significant topsides weight and space requirements (can add between 6,000 to 16,000 tonnes of additional operating weight), requiring gas processing design to be as simple as possible.*

- *CO_2 import quality, quantity and import pressure and temperature. Imported CO_2 is transported in dense phase but may need to be boosted offshore to meet the CO_2 wellhead injection pressure. Also impurities in the imported CO_2 (such as O_2 in flue gas) will impact material selection.*

- *CO_2 properties such as low temperatures and solids formation/blockage in flare, blowdown and drainage systems.*

- *Material issues due to CO_2 corrosion. Will require CRAs upstream of gas dehydration and the potential for stress corrosion cracking (SCC) if O_2, H_2S or elemental Sulfur is present. Also, seal material compatibility is critical for reuse of existing equipment.*

- *In some cases, choosing well locations or the re-use of existing oil and gas facilities might be affected by the location of existing wells and whether or not they can be re-used. This requires assessments of wellbore and completion integrity to assure that these wells will meet the integrity requirements of CO_2 injection wells. The spatial and economic advantages and disadvantages of these need to be weighed against those of new wells (IEAGHG, 2010).*

- *Unlike onshore reservoirs that are typically low permeability and have been water flooded (1-100 mD), offshore reservoirs have higher permeabilities (100 – 1000 mD) and higher well cost requires much larger well spacings. Gravity segregation will also play a critical role and may require a pilot to address the displacement efficiency adequately. In addition, since development costs are much lower onshore, this allows for higher well densities and lower reservoir permeabilities.*

<u>*Horizontal Wells*</u>

Pattern arrays of alternating horizontal injectors and producers have been recommended for two reasons:

- *Conformance management with horizontal wells placed at the bottom of the formation to reduce gravity segregation,*

- *Low permeability reservoirs, to reduce the well count and achieve the required throughput rates for economics*

<u>Pilots</u>

Offshore CO_2 pilots are much more challenging and offshore generation of CO_2 is problematic. A new concept of offshore tankering of CO_2 may provide increased options for CO_2 pilots (Jenvey, 2010).

Kuuskraa and Malone (2016) studied the potential application of CO_2 EOR to oil reservoirs in the offshore Gulf of Mexico from the Bureau of Ocean Energy Management (BOEM) database that contained a total OOIP of 69 billion barrels (11 billion m^3) in 531 oilfields. The study excluded 391 of these oilfields, representing 35% of the OOIP, as not being amenable to CO_2 EOR based on their size, MMP, and residual oil saturation. The technical and economic evaluation of the remaining oilfields shows the economically recoverable resource (ERR) from the GOM offshore is 0.8 billion barrels (0.13 billion m^3), a small fraction of the technically recoverable resource (TRR) of 23.5 billion barrels (3.66 billion m^3). The study estimates that with Next Generation CO_2 EOR technology, the ERR increases significantly to 14.9 billion barrels (2.37 billion m^3).

A2.7 SIMULTANEOUS CO_2 EOR AND STORAGE PROJECTS (SAINI, 2017)

The petroleum industry's long and successful record of secure underground injection of CO_2 for enhanced oil recovery has helped the world to embrace geologic CO_2 storage as first-order technology for abating the anthropogenic GHG emissions. The Global CCS Institute defines a large-scale integrated carbon capture and storage project (LSIP) as a project involving the capture, transport, and storage of CO_2 at a scale of:

1. *At least 800,000 (154 bcf) metric tons of CO_2 annually for a coal-based power plant, or*

2. *At least 400,000 (77 bcf) metric tons of CO_2 annually for other emissions – intensive industrial facilities (including natural gas-based power generation).*

Projects categorized by the Global CCS Institute as LSIPs must inject anthropogenic CO_2 into either dedicated geological storage sites and/or EOR operations. The majority of LSIPs (9) are in North America [USA – 7 and Canada – 2], where the petroleum industry has mastered the commercial CO_2 EOR technology. Brazil, Saudi Arabia, and the United Arab Emirates (UAE) each have one LSIP.

Key Features

Table A2-3 provides a summary of key geologic and operational characteristics and reservoir parameters for the main LSIPs and other simultaneous CO_2 EOR and storage sites currently operational in North America. The majority of these projects (9 out of 11) rely on the CO_2 captured by natural gas processing or industrial separation units, while the remaining two are coal-based facilities that supply the Weyburn-Midale CO_2 EOR and storage project in Canada. However, there appears to be a major push by China to capture CO_2 at its coal-fired power plants and use it for simultaneous CO_2 EOR and storage projects, and if successful may lead to more such projects in countries such as India and China.

Table A2-3 - Key geologic and reservoir parameters for current North American LISPs (Saini, 2017)

Geologic characteristic/ reservoir Parameter*	**Unit**	**Weyburn oil unit**	**Bell Creek**	**SACROC unit**	**West hastings**	**North Burbank oil unit**	**Pinnacle Reefs (Michigan's Northern Reef Trend)**	**Farnsworth unit**
Formation		Charles formation [Marly (upper dolostone unit) & Vuggy (lower limestone unit)]	Muddy (Newcastle)	Canyon Reef (limestone)	Frio sandstone	Burbank Sandstone	Guelph formation (brown Niagaran)	Upper morrow
Geological age		Mississippian	Cretaceous	Pennsylvanian	Oligocene	Pennsylvanian	Silurian	Pennsylvanian
Hydrocarbon trap type		Truncated stratigraphic	Stratigraphic	Reef	Structural	Stratigraphic	Reef	Stratigraphic
Overlying caprock(s)		Midale evaporate with Watrous aquitard as regional seal	Mowry shale	Wolfcamp shale	Anahuac shale	Cherokee shale	A-2 evaporite (top) A-1 evaporite (flank)	Thirteen Finger limestone
Caprock (s) average	ft.	6.5-36 (Midale	<3000	600-1100	600	45-70	<290	118

Geologic characteristic/ reservoir Parameter*	Unit	Weyburn oil unit	Bell Creek	SACROC unit	West hastings	North Burbank oil unit	Pinnacle Reefs (Michigan's Northern Reef Trend)	Farnsworth unit
thickness		evaporate)						
Formation depth	ft.	4900	4500	6200-7000	5500	3000	5400-5700	7545-7950
Avg. reservoir thickness	ft.	19.5 (Marly) 49 (Vuggy)	30-45	229	>700	50	278 (maximum)	54
Formation pressure at discover	psi	2300	1180	3122-3300	2740	1350-1600	2400	2200
Formation temperature	ºF	138	110	130	160	122	108	167
Cumulative oil production to date	Million barrels	366	133	1400	582		0.47 (dover 33)	19
Oil gravity	ºAPI	25-34	32-41	42	31	39-41	47.9	38
Formation water salinity	ppm	20,000-310,000	5000	159,000	>100,000	85,000	Very high	3600
Avg. porosity	%	26 (Marly) 11 (Vuggy)	25-35	9	29	20	4	3-21
Avg. permeability	ml	10 (Marly) 15 (Vuggy)	150-1175	30	500-1000	50-80	12	0.1-700
EOR type		Combined miscible simultaneous but separate CO_2 only. Water only. And water alternating as injection strategy using a combination of horizontal CO_2 injectors and horizontal producers and vertical water injectors and vertical producers.	Continuous miscible CO_2 injection (5-spot pattern)	Miscible Water Alternating Gas (WAG) (5-spot well pattern)	Continuous miscible CO_2 injection water only. And water alternation gas (5-spot pattern)	Miscible Water Alternation Gas (WAG) (staggered line drive well pattern)	Top down CO_2 injection (vertical injector & horizontal producer)	Hybrid water alternating with CO_2 gas injection (WAG) (5-spot well pattern)
Reported reservoir pressure prior to CO_2 injection	psi	2150-2250	1572	2400	1800	900	700	4700

The Sacroc Unit (storage site for Val Verde LSIP) has stored the maximum CO_2 (55 million tonnes/10.6 tcf), since it has been on injection the longest, since 1972. The Weyburn-Midale (operational since 2000) has stored almost 22 million tonnes/4.24 tcf of CO_2, and the West Hastings (Air Products LSIP) and Bell Creek (Lost Cabin LSIP) have injected 3 million and 2.75 million tonnes (578 and 530 bcf) respectively since start of injection in 2013.

Majority of the storage sites are either stratigraphic traps or closed pinnacle reef structures encased in thick impermeable formations that have served as effective seals for the hydrocarbon deposits. The wealth of geologic and reservoir data from long-term secondary and EOR operations have given additional confidence in selecting these sites as first-order storage sites for anthropogenic CO_2 storage.

A2.8 *CURRENT LARGE SCALE INTEGRATED CARBON CAPTURE AND STORAGE (LIST PROJECTS (OUTSIDE OF NORTH AMERICA)*

Uthmaniyah CO_2 EOR Project (See Section 8.3 - Case Study # 3)

Abu Dhabi CCS Project (Phase 1: ESI CCS Project)

In November 2016, the CCS facility at Emirates Steel Industries (ESI) steel plant in Abu Dhabi, UAE started to capture around 0.8 million tonnes (154 bcf) of CO_2 per year and supply to ADNOC's onshore Al Rumaitha and Bab fields via a 43 km (27 miles) pipeline for EOR injection. The project was preceded with a 2-year successful CO_2 EOR pilot test in the Rumaitha field (Global CCS Institute 2016g). With CO_2 from its gas processing plants, Abu Dhabi National Oil Company (ADNOC) will begin increasing the oilfield injection rate in 2021 to an expected 0.47 million tonnes (91 bcf) of CO_2 per year) by 2027, freeing for other uses natural gas now being reinjected for EOR. ADNOC is also evaluating implementing CO_2 EOR in its offshore oil fields and has a longstanding goal of increasing ultimate recovery to 70% of oil originally in place (OGJ, January 18, 2018).

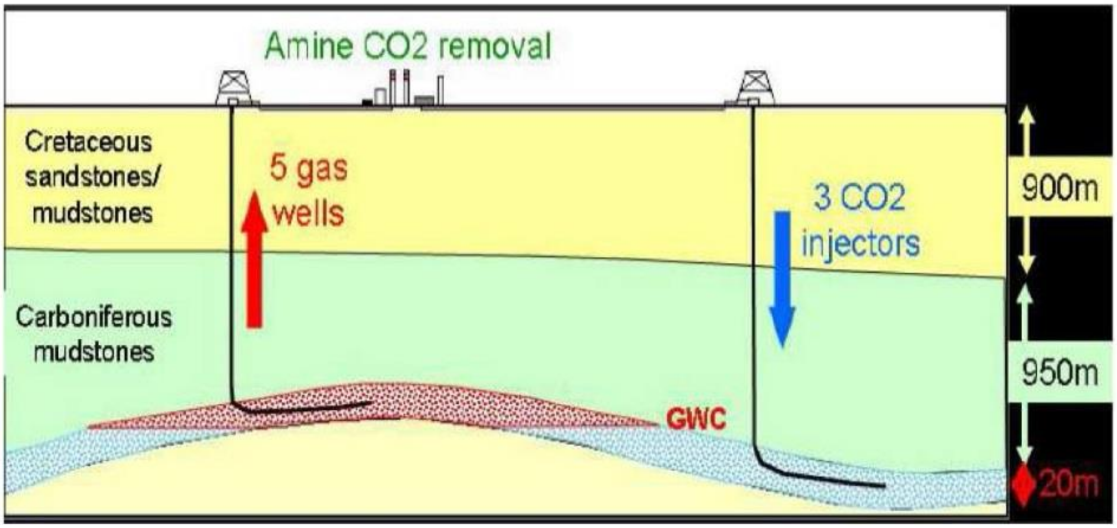
Petrobras Santos Basin Pre-Salt Oil Field CO_2 EOR and Storage Project (See Section 8.1 - Case Study # 1)

Carbon Dioxide Storage at In Salah

The In Salah Gas (ISG) project, a joint venture between Sonatrach, BP and Statoil, is currently executing a phased development of eight gas fields in the Ahnet-Timimoun basin in the Algerian central Sahara desert, 1,200 km/746 miles south of Algiers. These fields comprise an area of 25,000 km_2 (9,600 mi_2) and have estimated recoverable gas reserves of 0.23 trillion m^3 (8.1 trillion ft^3). The gas from these fields contains 1% to 10% CO_2, which is removed at the Krechba central processing facility (CPF). CO_2 and any residual H_2S in the produced gas are removed by monoethanol amine (MEA) absorption and the treated gas (< 0.3% CO_2) is transported by pipeline to export terminals. The ISG project started in 2004 and is currently producing 9 billion m^3/year (320 billion ft^3/year) of gas for export.

The producing gas reservoir is about 20 m (66 feet) thick and lies about 1,900 m (6,200 feet) deep below a 950 m (3,100 feet) thick caprock formation of carboniferous mudstones. A 900 m (3,000 feet) thick layer of Cretaceous sandstone and mudstone lies above the mudstone section. Produced gas from the reservoir is treated at the CPF to remove CO_2, H_2S and other impurities. Following separation from the natural gas stream at the Krechba processing facility, the CO_2 is compressed in four stages up to 200 bars (2900 psi) and dehydrated. It is then reinjected into water-saturated rock down dip of the same reservoir from which the gas is produced. The three CO_2 injection wells have horizontal sections up to 1.8 km (1.1 mile) in length (Wright, 2007 a, b). The horizontal well completions have been directed NE/SW to intersect the main fracture orientation in the reservoir sandstone (Mathieson et al, 2009) (Figure A2-5). Since 2004, approximately 3.5 million metric tons (3.9 million tons/675 bcf) of CO_2 have been separated from the produced gas and reinjected into the Krechba reservoir. One of the lessons learned is that legacy wellbore integrity is a key leakage risk that has to be effectively managed. Injection was suspended in 2011 due to concerns about the integrity of the seal (Ringrose et al, 2013).

Figure A2-5 - Schematic cross-section through In Salah injection site (Mathieson et al, 2009, IEAGHG, 2010)



The joint venture conducted extensive monitoring of CO_2 storage using a variety of techniques such as surface and soil gas monitoring, downhole gas measurements and tracer chemical tagging. Geophysical and InSAR satellite monitoring were also conducted to check for ground deformation and micro-seismicity. Important lessons learned about CO_2 storage during the design, startup and operation of the ISG project included: (1) need for detailed geologic and geo-mechanical characterization of the reservoir and the overburden that helped in developing the injection strategy and to ensure the long-term integrity of the storage project, and (2) importance of flexibility in the design and control of the capture, compression and injection well systems (Oilfield Review, 2015)

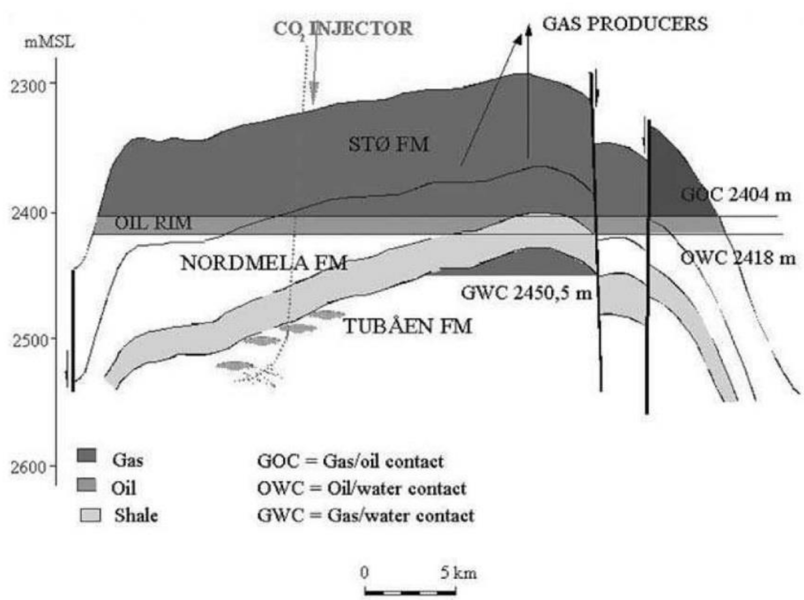
Sleipner, Norway (Chadwick and Eiken, 2013 and IEAGHG, 2010)

The Sleipner area gas development is located in the Central North Sea approximately 240 km/149 miles west-southwest of Stavanger, Norway. The Sleipner CO_2 storage partners are Statoil (58.35% and operator), ExxonMobil E&P Norway (17.24%), Lotos Norway AS (15%), and Total E&P Norge (9.41%). The development embraces the Sleipner Ost and Sleipner Vest gas and condensate fields (and tie-ins from a number of satellite fields). Sleipner Ost came on stream in 1993 and Sleipner Vest in 1996, with CO_2 injection commencing in 1996. Sleipner is the world's largest-running industrial-scale storage project and so far the only example of CO_2 underground storage arising as a direct response to environmental legislation.

Snøhvit, Norway (IEAGHG, 2010)

At the Statoil operated Snøhvit LNG project, CO_2 is currently being injected into a deep saline formation in the Barents Sea. The Snøhvit project is the first LNG development in Europe. Production from the Askeladd, Albatross and Snøhvit fields started in September 2007 with a projected 30-year lifetime and injection of CO_2 at Snøhvit commenced in May 2008. The CO_2 content of the field gas must be reduced from 5-8% to less than 50 ppm prior to conversion to LNG. The 0.75 Mt/yr (145 bcf/yr) CO_2 removed from the natural gas, using amine technology, is injected into the Tubåen formation situated below the Stø formation (Figure A2-6), a Jurassic gas reservoir (Maldal and Tappel, 2004).

Figure A2-6– Simplified cross section through the SnØhvit field (Maldal and Tappel, IEAGHG 2010)



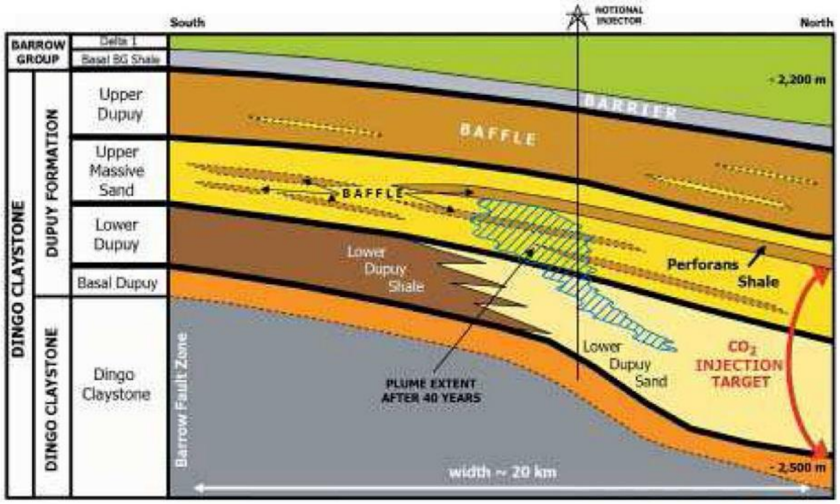
Gorgon, Australia (IEAGHG, 2010 and Chevron, 2016)

The Gorgon Project as a Joint Venture (Chevron Australia, Operator - 47%, ExxonMobil – 25%, Shell – 25%, Osaka Gas – 1.25%, Tokyo Gas – 1%, and Chubu Electric Power – 0.417%) will exploit the natural gas resources of the Greater Gorgon area, offshore Western Australia. The Gorgon Project is a three-train LNG and domestic gas facility on Barrow Island and the first shipment of LNG was shipped to Japan in March 2016.

The natural gas in Gorgon contains up to 14% CO_2. The CO_2 will be separated from the produced gas at the gas-processing facility on Barrow Island, compressed to a supercritical state, and then transported by a 12 km (7.45 mile) pipeline to the injection site for storage on the island. If feasible, the project will involve the injection of up to 4.9 Mt/y (867 bcf/y) extracted from the field gas into the Dupuy Saline Formation 2,300 m (7,546 feet) below Barrow Island (Figure A2-7). A total of 125 Mt (24.1 tcf) CO_2 (95% of the reservoir CO_2) is expected to be stored over the project life. Due to delays with the Gorgon gas project, the planned start of CO_2 injection has been delayed from 2014 to late 2017/early 2018.

Nine injection wells are currently planned, which will be drilled directionally from three locations. The modelling of CO_2 migration in the heterogeneous injection horizon with an average permeability of 25 mD predicts preferential CO_2 migration along high-permeability layers resulting in a non-uniform plume spread. A monitoring program to keep track of CO_2 behavoir after injection will include: a number of observation wells to monitor injection rates and pressures, seismic monitoring of CO_2 migration, wireline logging, geochemical analyses of Dupuy Formation waters and installation of CO_2 detection devices to detect leakages (Chevron, 2005, 2006). Four water production wells with rate of approximately 63,000 barrels per day (~10,000 m^3/day) are planned to manage reservoir pressures and brine displacement in an updip location of the injection wells (Malek, 2009). In case of excessive pressure build-up due to poor injectivity, remediation options proposed by the operator include increasing the completion interval and an additional up to 9 injection wells.

Figure A2-7 – Schematic plume migration of injected CO_2 in the Dupuy Formation (Chevron, 2005, IEAGHG, 2010)



Cranfield, Mississippi, CO_2 Storage Project

The Southeast Regional Carbon Sequestration Partnership (SECARB) project in Cranfield Field in western Mississippi has been conducting testing and monitoring approaches to document storage efficiency and storage permanence under condition of both CO_2 EOR as well as CO_2 injection downdip into brine. Denbury Onshore LLC is host for the study and has brought a depleted oil and gas reservoir, Cranfield Field, under CO_2 flood. Injection was started in July 2008 with injection rates reaching greater than 1.2 million tons/year through 23 wells. Injection is into coarse grained fluvial deposits of the Cretaceous lower Tuscaloosa formation in a gentle anticline at depths of 3300 m (10,800 feet). The structure is created by a deep-seated salt dome with total thicknesses of the productive sand in the gas cap and the oil zone 19 m (63 feet) and 9.4 m (31 feet) respectively. A team of researchers from 10 institutions has collected data from five study areas, each with a different goal and different spatial and temporal scale (Hovarka et al, 2011).

Tuscaloosa oil and gas production at Cranfield began in 1944 with drilling of wells in the oil rim below a large gas cap at the top of the structure. Gas was recycled for pressure maintenance until 1959, when the gas cap was produced, decreasing pressure and ending production. By 1966, nearly all the wells were plugged and abandoned and the Tuscaloosa reservoir was idle and in pressure recovery until Denbury began injection for EOR purposes in 2008.

CO_2 injection at Cranfield has a number of advantages suited for conducting pilot projects for evaluating success of geologic storage objectives:

- *Injection is into porous and permeable sandstones with mudstone confining systems, a typical setting for the Gulf Coast region, with results that can be applied widely*
- *Large volumes of CO_2 are commercially available (natural CO_2 source from Denbury's Jackson Dome reservoir and transported via pipeline*
- *Operator Denbury's experience and logistical support in the areas of CO_2 handling best practices, pipeline transport, permitting and liability management*
- *Via SECARB, Denbury cooperation wells were placed further downdip than normal (below the oil-water contact) and injected at higher than normal rates, replicating rates needed for brine storage*
- *Staging the test at the start of tertiary recovery with relevance to other sites. The extended reservoir shut-in period allowed reservoir pressure to recover to near original and fluid re-equilibration. This will be the common initial condition in CO_2 projects injecting in non-oil and gas productive saline formations.*

For CO_2 storage, the magnitude and propagation of the pressure increase are the controlling factors for storage integrity and storage efficiency (Choi et al, 2011). In the case of a compartmentalized system with closed boundaries, CO_2 injection may lead to significant pressure buildup and the potential to reactivate existing faults and/or create fractures in the overlying or underlying sealing rocks, resulting in CO_2 leakage or migration.

Results from numerical modeling studies conducted by Choi et al (2011) using the CMG-GEM compositional flow simulator indicate the following:

- *Pressure measurements are very useful to understand reservoir boundary conditions which ultimately determine the movement of the CO_2 plume*
- *Reservoir characterization, especially permeability is of utmost importance in modeling of pressure histories for CO_2 injection*
- *Pressure monitoring would be more valuable for CO_2 injection into brine aquifers than it would be for CO_2 EOR purposes.*

Also, numerical modeling done by Hosseini et al (2018) showed that:

- *CO_2 injected for EOR will partition into several phases in the target formation. The distribution into free or residually trapped oil, gas and brine phases depends on many factors such as reservoir temperature, pressure, initial fluid saturations, brine salinity, and relative permeability parameters and evolves through time including in the post-injection period, during which it will tend to stabilize.*

- *The above variations are significant and depend on the operator's selected development strategy: continuous gas (CO_2) injection, WAG injection, water curtain injection or combinations, with WAG operations appearing to be the most optimal approach for both EOR as well as storage objectives.*

Data from the listed projects above will provide valuable guidelines for future geologic CO_2 storage projects, both for onshore and offshore projects.

APPENDIX 3 - STANDARD OPERATING PRACTICES (SOPS) FOR DESIGNING, CONSTRUCTING, AND OPERATING CO_2 INJECTION WELLS

A3.1 SCOPE

The practices for designing, constructing, and operating CO_2 injection wells are often called Standard Operating Practices (SOP) and intended to establish requirements and recommendations for relevant wells in Enhanced Oil Recovery (EOR) projects or for the geological storage or disposal of CO_2. The former has a large number of operating wells in the USA and the latter has only a small number. In many cases, CO_2 is injected with other suitable fluids associated with oil and gas production operations, such as treated water from oil and gas producing zones. This is often done in the EOR process called WAG (water alternating gas) where stages of water and CO_2 improve the flow of oil out of formation pore spaces and into production wells. Relevant storage or disposal wells also use these SOPs for environmentally safe and permanent containment of unwanted fluids, such as H_2S (aka. acid gas wells).

These SOP are primarily applicable to CO_2 injection into hydrocarbon reservoirs and saline aquifers. This SOP also provides recommendations for the development of management documents, community engagement, risk assessment, and risk communication. The SOP's primary objective is to maintain sustained well integrity to minimize Health, Safety, and Environmental (HSE) risks, and avoid unnecessary costs that can negatively affect operating expenses (OPEX) and capital expenses (CAPEX).

A3.1.1 CO_2 and CO_2-Related Injection Stream

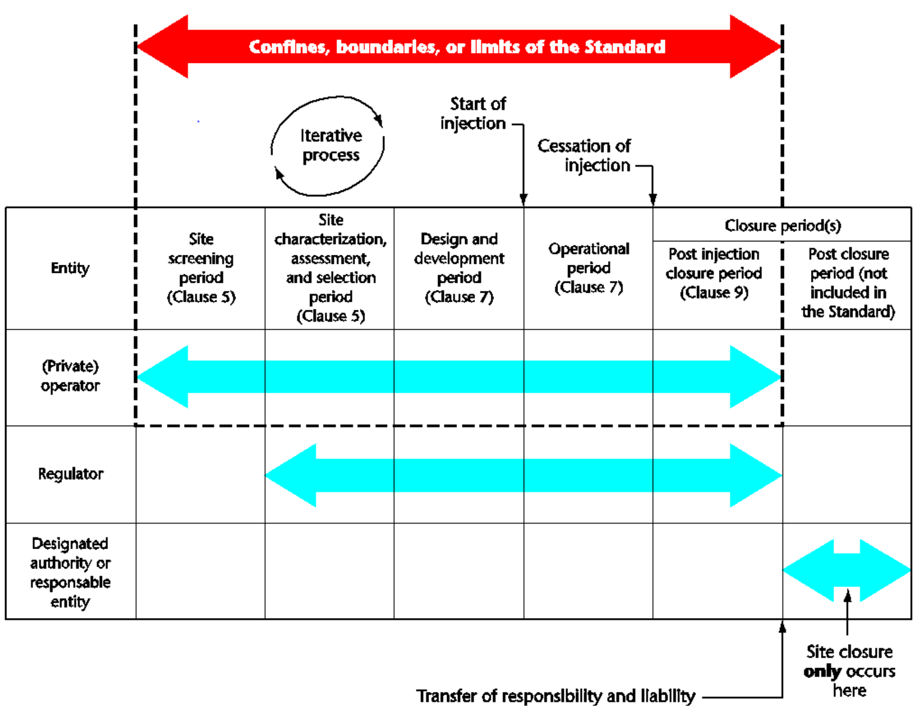
These SOP apply providing a well that is a conduit for a stream of CO_2 from the surface into relevant formations. This SOP does not permit waste and other matter to be added for the purpose of disposing of impurities defined in local regulations as waste. However, a CO_2 stream can contain incidental associated substances from a) producing oil and gas formation(s), b) production wells, c) drilling, workover, and hydraulic fracturing operations, d) fluid treatments to remove unwanted constituents prior to injection, e) capture (separation from produced oil & gas, etc.), f) injection operations, and g) trace materials added to assist in monitoring and verifying CO_2 migration. Any of the above associated substances and trace materials in the CO_2

should be small enough (dimensionally & in volume) and sufficiently chemically inert to pass through the injection well and the formation's permeability without any adverse effects (plugging scales, pore-throat particle plugging, etc.) on injection performance.

A3.1.2 CO_2 Well Life Cycle

The CO_2 well's life cycle covers all aspects, periods, and stages of the project, beginning with those necessary to initiate the project (including site screening, characterization, assessment, selection, engineering, permitting, and construction), that lead to the start of injection and proceeding through subsequent operations until cessation of injection; and culminating in the post-injection period, which can include a post-injection closure period and, if regulations require, a post-closure period. This SOP specifies that the post-closure period occurs only if a transfer of responsibility and liability to a designated authority or other responsible entity takes place. If a transfer does not occur, the project remains in the post-injection closure period and formal site (field, lease, or section thereof) closure does not occur. This Standard does not specify post-closure period requirements. Figure A3-1 illustrates the confines, limits, and boundaries of this SOP.

Figure A3-1 CO_2 EOR or Disposal/Storage Project Life Cycle



These Standards do not apply to:

(a) the post-closure period;
(b) CO_2 injection into unsuitable locations: coal or other mines, or salt caverns; and
(c) underground storage into any form of man-made containers.

A3.1.3 Application of Requirements in Standard

In this SOP, “shall” is used to express a requirement, i.e., a provision that the user shall satisfy in order to comply with the standard; “should” is used to express a recommendation or that which is advised but not required; “may” is used to express an option or that which is permissible within the limits of the standard; and “can” is used to express possibility or capability. Notes accompanying clauses do not include requirements or alternative requirements; the purpose of a note accompanying a clause is to separate from the text explanatory or informative material. Notes to tables and figures are considered part of the table or figure and may be written as requirements. Annexes are designated normative (mandatory) or informative (non-mandatory) to define their application.

A3.1.4 SI Units

The values given in SI units are the units of record for the purposes of this Standard. The values given in parentheses are for information and comparison only.

A3.2 MANAGEMENT SYSTEMS FOR INJECTION WELLS – WELL CONSTRUCTION AND OPERATING MANAGEMENT

Defining and implementing standards for geological storage/disposal is an essential component in the development of CO_2 injection and storage/disposal project. Management systems are essential for the implementation and public credibility of geological storage processes. They are typically prepared during the well planning and field development phases and need to be flexible to address changes during later phases of the project’s life cycle. They should be robust to ensure that they meet site-specific project and regulatory needs. Management systems for a CO_2 injection and storage/disposal project interconnect through all of the project’s activities and phases.

A3.2.1 General

The intent of management systems is to ensure that existing best practices are followed and to allow and promote improvement in the oil and gas field including the CO2 injection and storage project operating therein. Management systems also help to ensure that quality assurance/quality control, regulatory compliance, process improvements, and efficiency improvements are integrated into regular management processes and decision-making, as well as ensuring project transparency so that project stakeholders, regulatory authorities, and the public develop confidence in the management and implementation of storage projects. Another important function of management systems is the embedment of a risk-management process into the culture and practices of a storage project to help ensure that the circumstances or events that can affect project objectives are identified and managed. Risk management should include consideration of both internal and external factors.

A3.2.1.1 ***Project operator's roles and responsibilities***

The scope of the project operator's roles and responsibilities shall include operations that fall within the project boundaries as defined within Clause A3.2.3. These operational activities shall include those over which the project operator has control or significant influence, including those that have significant environmental or social impacts.

The project operator shall be responsible for:

(a) *all activities related to the storage project (including design, monitoring, and verification) and for the coordination and integration of those activities, especially activities that involve the handling and fate of the injected* CO_2*;*

(b) formulating a written statement of the storage project's objectives, principles, and values and communicating this statement throughout the project organization and to project stakeholders and regulatory authorities

(c) coordinating, integrating, and communicating the activities and responsibilities of persons or organizations related to the storage project to project stakeholders and regulatory authorities

(d) coordinating the activities of other organizations acting on its behalf;

(e) ensuring that all persons and organizations employed by the project operator comply with the requirements of this SOP;

(f) *project risk identification, risk evaluation, and risk management during the life cycle of the storage project, and for coordinating activities to minimize risk; and*

Note: *Requirements for risk management are specified in <u>Clause</u> A3.3.*

(g) *determining and ensuring the availability of the physical, financial, and human resources required to meet the objectives and principles of the storage project.*

The project operator can change over the project's life cycle. In such cases, the former project operator shall be responsible for ensuring that all necessary documentation, materials, and processes are transferred to the subsequent project operator. The subsequent project operator shall be responsible for the smooth transition of management systems and processes. Records should be retained by both the former and subsequent project operators.

A3.2.1.2 <u>Continuous improvement</u>

The project operator shall continuously improve the management systems by adapting to changing operational conditions or regulatory circumstances. Continuous improvement shall be undertaken for all activities of the storage project, including planning, design, development, operation, monitoring, and closure. The project operator shall develop a continuous improvement process that identifies deficiencies and improvements, assesses alternatives, implements corrective actions, evaluates action effectiveness, and assesses the need for further action.

A3.2.1.3 <u>Project stakeholders</u>

The project operator shall identify project stakeholders early in the storage project's life cycle and engage them during all phases of the project. The project operator shall provide educational or informational resources relating to the storage project to project stakeholders, including employees.

Note: *Examples of stakeholders are included in the definitions Appendix 1.*

A3.2.1.4 <u>Project definition</u>

The project operator should define a phased project scope that maintains and communicates the clear alignment of project activities with the storage project's objectives and principles. The project operator should organize, resource, and direct the activities of the CO_2 injection and storage/disposal project in accordance with the project's time periods specified in this Clause. A project operator may employ project periods different from that specified in this Clause but should describe and document support for the alternative periods.

During all project periods, the project operator shall be responsible for obtaining and allocating resources for the work at hand, setting specific period objectives and schedules, and setting priorities in regard to competition for resources. Particular responsibilities apply to the project operator during specific project periods. The following list of project periods includes some of those requirements:

(a) *Site screening period: the project operator shall set conceptual, geographical, geological, and hydrogeological criteria for, and boundaries of, the potential storage sites (see Clause A3.2.9 and Clause A3.2.3 for details).*

(b) Site selection and characterization period: the project operator shall:

(i) set performance assessment criteria by which the development of the project can be evaluated, and determine the relative importance of the attributes by which candidate site(s) will be compared;

(ii) ensure that the candidate site(s) have adequate capacity to accept the anticipated final volume of CO_2, adequate injectivity to accept the CO_2 stream at the desired supply rates, and containment characteristics that will ensure effective retention of the injected CO_2; and

(iii) establish the context and expectations for risk assessment and risk management, to ensure that the selected site(s) do not pose unacceptable risks to other resources, the environment, and human health, or to project developers, owners, and operators.

(c) Design, development, and operation period: the project operator shall

(i) develop and disseminate procedures for a QHSE (quality, health, safety, environment) protection program;

(ii) develop and disseminate protocols that promote the effective integrated functioning of project operator and subcontractor organizations;

(iii) select appropriate materials and methods for site development;

(iv) apply industry standards for site design, development, and operations, including wellsite design, drilling operation procedures, facility construction, monitoring hardware installation, and site security and emergency procedures; and

(v) develop operations and maintenance procedures for monitoring and improving the performance of the complete integrated storage system over the project's lifecycle.

(d) Post-injection period: the project operator shall

(i) set criteria for well abandonment and inspection; and

(ii) set criteria for continued monitoring that meets regulatory requirements and continues the progressive reduction of uncertainties regarding the CO_2 plume fate.

(e) Closure period: the project operator shall

(i) demonstrate that the CO_2 storage complex has appropriate long-term monitoring systems in place;

(ii) establish archives and attendant systems to ensure the future public availability of project data and knowledge;

(iii) prepare a plan for long-term stewardship;

(iv) decommission (or schedule for decommissioning) all surface equipment associated with the storage project that is not needed for the post-closure period;

(v) plug and abandon wells within the storage site that are not considered necessary for future monitoring purposes; and

(vi) ensure proper documentation of, and adherence to, transfer of responsibility requirements, where applicable.

(f) Post-closure period: this SOP does not cover the post-closure period. Local regulations shall be used to determine the operator's responsibilities such as archiving relevant oil and gas field and CO_2 injection and storage/disposal data. See Figure A3-1.

A3.2.2 Project Boundaries

A3.2.2.1 <u>Responsibility</u>

The project operator of a CO_2 injection and storage/disposal project bears responsibilities that can differ among the multiple overlapping dimensions potentially affected by the project. Within each dimension, the project boundaries can be defined in terms of legal descriptions (land surveys), contracts, permit conditions, surface and/or subsurface operational activities, or the physical effects (current or anticipated) of the project.

A3.2.2.2 ***Organizational boundaries***

The organization or person acting as the project operator for the CO_2 injection and storage/disposal project shall be identified and specific responsibilities and reporting relationships shall be defined between the project operator and designated persons and organizations involved with the project. If control of the project is shared among organizations (e.g. lease partners), the project's internal boundaries among organizations and areas of responsibility shall be defined.

A3.2.2.3 ***Operational boundaries***

The operational boundary of a storage project encompasses the activities that are directly controlled by the storage project. Activities within the project operational boundary include well drilling, CO_2 injection and storage/disposal project construction, site characterization, monitoring, personnel transportation, and CO_2 transportation that is internal to the storage project. For the purposes of planning and risk management, the project operational boundary shall be considered to include the communities within the area anticipated to be affected by the storage project and any temporary or mobile monitoring facilities.

A3.2.2.4 ***Physical boundaries***

The project operator shall define the surface and subsurface physical boundaries of the CO_2 injection and storage/disposal project. The surface physical boundary or boundaries shall include all project sites (injection sites, associated industrial facilities, and fixed, permanent monitoring facilities) and offices that pertain directly to the storage project. The project operator shall be responsible for all activities within the permanent surface boundaries over the project's life cycle and should establish the legal right to limit access within the permanent surface boundaries.

The subsurface physical boundary includes the subsurface pore volume within the designated rock formation(s) and its overlying surface area wherein CO_2 injection could impose important physical effects. Examples of important physical effects can include pore fluid (existing pre-injection) displacement and impacts upon known subsurface resources (oil, gas, water) or the exploitation thereof (e.g., impacts from fluid-pressure increases). The project operator shall estimate the nature and boundaries of subsurface effects and update and improve such estimates throughout the project's life cycle as new data become available.

A3.2.3 Management Commitment to Principles

A3.2.3.1 General

Persons in top management and other management roles throughout the project operator's organization shall demonstrate their commitment to best practices for the long-term safe geological storage of CO_2 by incorporating the principles specified in Clauses A3.2.4.2 to A3.2.4.4 into their actions and decisions.

A3.2.3.2 Internal principles

The project operator shall:

(a) *operate on the basis of sound science and engineering;*

(b) meet all legal and regulatory obligations and exceed them when appropriate;

(c) seek cost-effective means but allow a prudent margin for safety and environmental considerations;

(d) ensure safe CO_2 handling;

(e) identify and reduce project risks through an appropriate risk management system; and

(f) ensure that during the project's life cycle, the site will be monitored to ensure that unplanned occurrences can be addressed promptly (see Clause A3.5).

A3.2.3.3 External principles

The project operator shall:

(a) *operate in an open and transparent fashion with project stakeholders and regulatory authorities to build public understanding, trust, and credibility;*

(b) establish a local stakeholder advisory strategy and regularly engage with and seek input from local stakeholders;

(c) provide reports to the public when major milestones are arrived at or significant unplanned events occur; and

(d) *seek external independent assessments of significant project activities to ensure compliance with applicable standards and best practices.*

A3.2.3.4 <u>Health, safety, and environmental principles</u>

The project operator shall:

(a) *ensure that health, safety, and environmental protection for employees and local communities are the project's highest priorities;*

(b) *ensure the integrity of all facilities which includes preventing CO_2 leaks;*

(c) *develop and put in place an emergency response plan and designated team;*

(d) *upon completion of the project, convert the storage site and storage unit to a condition such that no negative impacts on human health or the environment are expected; and*

(e) *provide the resources to continually improve health, safety, and environmental protection.*

A3.2.4 Planning and Decision Making

A3.2.4.1 <u>General</u>

The project operator shall establish, document, implement, and maintain a management system and shall continually improve its effectiveness.

Note: *Examples of recognized management systems include ISO 9001 on quality management, ISO 14001 on environmental management, and ISO 31000 on risk management.*

A3.2.4.2 <u>Intellectual property</u>

EOR and geological CO_2 storage/disposal are oil and gas industry projects that could likely involve or concern multiple public (regulators, media, academia, etc.) and private (oil & gas services, vendors, subcontractors, etc.) organizations. While there is potential for both public and private benefit from the development of new technology, there is also potential for conflict and project failure because of disagreements over ownership of intellectual property (IP). Accordingly, the project operator should negotiate and establish early in the storage project's life cycle inter-organizational agreements that address the ownership of present and potential IP.

A3.2.5 Resources

A3.2.5.1 General

The project operator shall evaluate and document at regular intervals the resource requirements under its responsibility to ensure that the requirements are met throughout the project's life cycle.

A3.2.5.2 Competence of personnel

The project operator shall determine the necessary competence of persons doing work under its control that affect health, safety, and the environment, and ensure that these persons are competent based on appropriate education, training, skills, or experience. When appropriate, the project operator shall provide training or take other actions to achieve the necessary competence.

The project operator shall retain suitable documented information as evidence of competence. All employees shall be trained on safe operating procedures relating to their job responsibilities and empowered with stop work authority related to safety issues. At regular intervals, the project operator shall review required competencies to ensure that persons under its control remain up-to-date on changing regulations, knowledge, and best practices. The project operator shall ensure that subcontractors have equivalent programs and can demonstrate the competency of their personnel.

A3.2.5.3 Equipment management

The project operator shall retain, manage, and direct appropriate equipment and infrastructure to facilitate all project phases including the documentation of infrastructure and equipment allocations for the CO_2 project. The project operator shall further consider establishing emergency provisions to prepare for loss of equipment or infrastructure failure to a point that adversely affects site development, operations, or closure activities.

A3.2.6 Communications

A3.2.6.1 General

The project operator shall develop a communication plan early in the project, which shall include a trained, designated liaison (aka. spokesperson) for media relations. The project operator shall ensure that communication processes are clearly defined and that they are effective in advancing the storage project's objectives.

A3.2.6.2 Public communications

When the brine CO_2 project is in or near populated areas, the project operator shall develop an open community outreach and engagement strategy. Input from the local community on the process and details of the strategy may be obtained. Local outreach and engagement should include public meetings, public notices, public updates, and site visits. A local newsletter and social media may be used as needed.

The project operator should publicly communicate information on project activities, including; regulatory matters, standards performance, and safety and environmental issues early in the project's life cycle, at regular intervals and when specific events occur. Public communications shall be clear, transparent, and accurate, and include scientific, technical, and economic information concerning the storage project, and be expressed in language that the general public can understand. There should be a designated individual with a published telephone number and email address to answer questions.

Public communications dissemination should include local community organizations and the local media. Employees can also be public stakeholders. The primary focus for local communication should be issues related to the storage project and to matters of local benefit and concern with respect to environmental, economic, and social outcomes. Public communications shall be respectful of all parties and respond to critics in a diplomatic and factual manner.

A3.2.6.3 Internal communications

Employees should be fully informed of the nature and circumstances of the storage project, its goals and targets, and its progress in achieving those goals. All internal communications shall be clear, direct, and accurate. Employees should be briefed on the regulatory expectations and requirements of government agencies and any guidance or operating procedures referenced by government regulations. Employees should be informed of all stakeholder groups and their project concerns to lessen any public confrontations. Internal communications should be conveyed to project contractors and consultants where appropriate.

A3.2.7 Documentation

A3.2.7.1 General

Documentation systems shall be designed in order to meet the needs of the project operator, from both an internal and external data collection and reporting perspective. Institutional knowledge should be recorded to allow for the transfer of pertinent project information to either a subsequent project operator or to meet regulatory reporting requirements, as needed.

A3.2.7.2 Information management

The storage project documentation shall include:

(a) documented statements of policy and objectives;

(b) documented plans, procedures, and records required by this SOP, including the risk management plan, the monitoring plan, the communications plan, and the post-injection and closure plan; and

(c) storage project artifacts and information products, including documents, records, and other data determined by the project operator to be necessary for the effective planning, operation, and control of its processes.

A3.2.7.3 Knowledge and information management systems

The project operator shall implement and maintain over the project's life cycle a centralized project information management system to organize, control, and archive project management artifacts, which may include, e.g., decision documentation, contracts, regulatory applications and approvals, financial records, engineering designs, meeting minutes, schedules, progress reports, communications, work plans and other artifacts. The project operator shall implement and maintain over the storage project's life cycle a centralized data management system to organize, control, and archive the diverse knowledge generated and acquired by the project, including scientific and spatial data sets, model results, maps, and other information products.

A3.2.8 Well Planning- Site Screening, Selection and Characterization

A3.2.8.1 <u>**General**</u>

The purpose of site screening and selection is to identify prospective CO_2 injection or storage/disposal sites, gather necessary information on the prospective sites, and use this information to select the most promising candidates for further characterization that help maximize CO_2 injection performance, and minimize CAPEX and OPEX. Subsequent characterization and assessment of a site should demonstrate that the candidate site is likely to have adequate capacity to accept the anticipated final volume of CO_2, appropriate injectivity to accept the CO_2 stream at the desired/supply rates, and containment characteristics that will ensure effective retention of the injected CO_2 over the time-scales established by the regulatory authorities in the respective jurisdiction. In addition, the characterization and assessment process shall demonstrate that storage of the CO_2 stream at the candidate site(s) does not pose unacceptable risks to other resources, to the environment and human health, and to project developers, owners, and operators.

The site screening, selection, and characterization process is inherently an iterative process, i.e., as more information is gained about the sites under study, sites that might have been thought to be suitable candidates will be eliminated from consideration and further study will need to be conducted on other prospective sites. Also, as a site is developed and operated, new data and information will be acquired or become available that will enhance the characterization and understanding of the site. Thus, while this SOP presents the screening, selection, and characterization process in a linear fashion, users of this Standard should anticipate applying its guidance iteratively. Sites currently used for CO_2 EOR may, in the future be used for CO_2 storage, in which case, operators will need an accounting system to quantify all the CO_2 that has been stored and ensure its retention (See Section 8.4 Oxy's Wasson Unit Case Study # 4 and the Oxy Denver Unit CO_2 Subpart RR Monitoring, Reporting and Verification (MRV) Plan, December 2015).

A3.2.8.2 Mechanisms for CO_2 trapping

The main mechanisms for CO_2 trapping in geological media are:

(a) *structural and stratigraphic trapping, in which the lateral movement of continuous liquid-phase, mobile CO_2 in response to buoyancy and/or pressure forces within the storage unit (depleted reservoir or aquifer) is prevented by low-permeability barriers (caprocks, or aquitards or aquicludes) such as shales or evaporites (halite and anhydrite);*

(b) *residual-saturation trapping, in which discontinuous liquid-phase CO_2 is immobilized in individual pores by capillary forces;*

(c) *mineralization or dissolution trapping, in which injected CO_2 reacts with the dissolved substances in the native pore fluid and/or with the minerals making up the rock matrix surfaces of the storage complex, with the result that part of the injected CO_2 is incorporated into the reaction products as precipitates forming solid compounds or minerals (aka. scale).*

Hydrodynamic trapping, or migration-assisted storage, is not a trapping mechanism by itself, but a combination of trapping mechanisms in laterally open deep saline aquifers where a combination of mechanisms may contribute to CO_2 trapping.

A3.2.9 Site Screening

During the site screening process, sites that possess one or more of the following characteristics should not be considered for CO_2 injection and storage/disposal:

(a) *Technical:*

- (i) *lacking the necessary capacity and injectivity to match the rate of the CO_2 stream and the volume(s) to be stored;*
- (ii) *lacking, based on existing information, containment for the required period of time (as might be determined by the designated regulatory authority in the respective jurisdiction), including at least one regionally extensive competent primary seal (cap-rock);*
- (iii) *located in areas where containment is likely to be affected by seismicity and tectonic activity, although the presence of seismicity per se should not preclude a site from being considered;*
- (iv) *located in areas of extensive and high-density faulting and fracturing subject to reactivation;*

(v) located in over-pressured systems, i.e., systems where the natural pressure is significantly higher than hydrostatic, with gradients greater than 15–16 kPa/m (0.663-0.707 psi/ft) and sometimes approaching lithostatic pressure;

(vi) located in short hydrodynamic systems, i.e., systems with relatively short travel distances from recharge to discharge areas, such as systems in intra-montane basins and thrust and fold belts;

(vii) lacking adequate monitoring potential in regard to the evolution, fate, and effects of the injected CO_2 stream; and

(viii) the mechanical integrity of legacy wells penetrating the primary seal cannot be confirmed or, if known, cannot be adequately remediated.

(b) Legal and regulatory:

(i) located within the depth of protected groundwater as defined in the respective jurisdiction;

(ii) located at depths and locations where communication with, and impacts on, protected groundwater can be demonstrated;

(iii) located at depths and locations where communication with, and may have negative impacts on, other natural resources (energy, geothermal, and mineral) can be demonstrated;

(iv) located in protected areas, e.g., national parks, and in environmentally sensitive areas as defined by designated authorities, that are likely to be affected by operations or loss of containment; and

(v) located in areas where surface and/or pore space rights or operating permits cannot be obtained, e.g., military bases and native reservations, unless approved by the proper authorities.

Evaluation for site screening involves a certain level of site characterization, but this characterization should be based on readily available data and information and should not require acquisition of new data and a significant evaluation effort. In some cases, sites deemed unsuitable based on these criteria can be found suitable once additional data and information become available or alternative field development injection schemes are applied (e.g., horizontal wells or production of aquifer water), or legal and regulatory changes allow development.

A3.2.10 Site Selection and Well Placement

Site selection and well placement decisions builds on the performed geological evaluation and land use considerations during the initial site screening process. Data, information and knowledge acquired during the screening process should be incorporated into the site selection process. In areas where sufficient data (direct and/or analog) are available, models may be developed during site selection. These models can be useful for identifying data gaps and for quantifying uncertainty with respect to initial estimates.

During the selection of sites and well placement locations that passed the screening process, the following should be assessed:

(a) subsurface criteria:

(i) capacity — further refinement of site storage capacity as more information is gathered and the injection potential is better understood. This can be accomplished by evaluating existing well logs and cores to determine reservoir thickness, lateral variation, continuity, porosity, heterogeneity, and water saturation;

(ii) injectivity —influences the number of wells, well design (horizontal versus vertical), and injection pressure. Injectivity can be estimated from the well's production history, core analyses, or hydraulic testing;

(iii) storage security, including the potential for CO_2 leakage through;

(1) weak seals along faults and fractures, assessment of which may include

(a) interpretation and reprocessing of legacy 2-D and 3-D seismic;

(b) review of aeromagnetic surveys, logs (structure mapping), pressure mapping, and geochemical analyses of water;

(c) identification of primary and secondary seals;

(d) ensuring that the primary seal is regional in scale; and

(e) assessment of seismicity and tectonic activity;

(2) legacy wells, whose investigation should include the

(a) number of wells penetrating the storage complex within the area of review;

(b) age and construction of the wells;

(c) well status (producing, suspended, or abandoned); and

(d) history of well interventions in the area (i.e, surface casing vent flow (SCVF), sustained casing pressure (SCP), gas migration (GM), and well remedial operations);

(iv) pore space ownership rights (identifying pore space owners in the area of review);

(v) proximity to and potential effects on other subsurface activities, e.g., mining, natural gas storage, and fracturing in or near primary or secondary seals (e.g., for shale oil or gas extractions);

(vi) proximity to and potential effects on valuable natural, energy, and mineral resources, e.g., producing hydrocarbon reservoirs, potable groundwater, geothermal energy, shale oil or gas, dissolved minerals (e.g., lithium), and sedimentary-basin minerals (e.g., Mississippi-type Pb-Zn deposits); and

(vii) capture and handling of any hydrocarbons produced by storage operations (if oil & gas production is part of the CO_2 EOR or storage/disposal strategy for pressure control); and

(b) surface criteria:

(i) existence of and proximity to rights-of-way between (potential) CO_2 source(s) and the storage site;

(ii) existence of infrastructure, e.g., pipelines and rights-of way, access roads, and power lines;

(iii) population distribution in the area overlying the storage site and along the projected path of the CO_2 plume;

(iv) land ownership in the area of review, as defined in the respective jurisdiction;

(v) proximity to other industrial facilities and to agricultural activities;

(vi) exposure to and proximity to vehicular traffic, roads, railways, aircraft, or shipping traffic;

(vii) nearness of protected wildlife habitats (including endangered species) and environmentally sensitive areas (wildlife management areas, community watersheds, conservancy areas, ecological reserves, and protected areas);

(viii) distance to nearby rivers and other bodies of fresh water;

(ix) closeness to national parks and other reserved areas (e.g., military bases and native reservations);

(x) present and predicted development of adjacent properties;

(xi) site topography and variability in weather conditions;

(xii) cultural and historical resources; and

(xiii) socio-economic conditions.

Some site selection and injection well placement criteria are not necessarily related to storage capacity, injectivity, and security per se, but, nevertheless, should be considered because they affect siting. Proximity for safety and security of storage should be evaluated and defined in accordance with the regulations in the respective jurisdiction. Proximity for economic reasons does not form part of the considerations specified in this Clause, although proximity to (potential) source(s) of CO_2 to be injected and existence of adequate transportation networks — or planned transportation, if such networks are absent — is an important consideration. By evaluating available surface- and subsurface-related information, site selection should result in a ranked list of selected potential sites for further characterization.

A3.2.11 Site Characterization and Assessment

A3.2.11.1 General

The characterization of a storage unit and of the primary seal shall consider all forms of CO_2 migration and trapping for liquid-phase CO_2. Geological, hydrogeological, geochemical, geophysical, and geomechanical studies, and identification and characterization of legacy wells, shall be conducted. This may be achieved through the collection, interpretation, and, where needed and applicable, reinterpretation of all available data, including (a) seismic data; (b) well test data; (c) geophysical wireline data (cased and open hole); (d) wellhead injection pressure data; (e) aquifer or reservoir pressure data; (f) data from core samples; (g) analyses of sampled fluids (formation water, oil, and/or gas); (h) water well samples, and (i) oil and gas production and fluid injection data (water, steam, gas, and solvents).

Supplemental data may be obtained through 3-D seismic surveys or similar methods such as VSP, DAS, and reservoir surveillance well's sensor and sampling data.

A3.2.11.2 <u>Geological and hydrogeological characterization of the storage unit</u>

A geological and hydrogeological characterization of the storage unit to provide a reasonable estimate of capacity, injectivity, and containment shall be completed before injection of the CO_2 stream and should include:

(a) Assessment of the lateral and vertical stratigraphic and lithological properties of the storage unit to determine the extent of the storage unit and establish its boundaries. Available data from wellbores, geophysical data, facies analysis, and regional geological studies should be used for this purpose;

(b) Identification and characterization of fault zones and structural features that could affect containment. 2-D and 3-D seismic surveys, and other geophysical/geochemical techniques should be used to identify any faults and structural anomalies. The locations of such features should be identified using the wireline log analyses, core analyses, and hydrogeological and flow analyses described in Clause A3.2.12.2 (e.g., comparison of flow regimes and formation water chemistries of the storage unit with porous and permeable units overlying the cap-rock), to ensure that these analyses provide insights on the transmissivity of these features;

(c) Determination of the dip angle and direction of the storage unit and its distance to sub-crop or outcrop, if such is the case;

(d) Mapping of the depth, top, and thickness of the storage unit using appropriate mapping tools and assessment of the degree of compartmentalization that could limit capacity and injectivity;

(e) Assessment of porosity distribution in the storage unit using wireline logs and core analysis data;

(f) Evaluation of the initial pressure distribution in the storage unit (prior to human activities, if any) and of the current pressure distribution if the initial pressure is affected by production or injection of fluids (e.g., oil, gas, or disposal water);

(g) Evaluation of injectivity, which is a measure of the rate at which CO_2 can be injected into the formation. This parameter should be determined by performing an in-situ injectivity test and transient pressure analysis with an appropriate fluid, inverse geomechanical analysis of surface deformation measurements via satellite radar or surface tiltmeter array measurements, analysis of downhole micro-deformation measurements via tiltmeter arrays in surveillance wells, conducting core flood tests using core samples from the storage unit, and/or by performing numerical simulations;

(h) Evaluation of the background flow regime in the storage unit, including direction and strength. Reservoir and hydrogeological studies should be conducted to effectively characterize the velocity and direction of the flow of water;

(i) Evaluation of the potential total volume theoretically available for CO_2 EOR and storage/disposal (using viable injection scenarios) based on the porosity, conductive permeability, and dimensions of the storage unit and of any flow restrictions such as limited displacement and compressibility of existing pore fluids. This volume can then be converted into mass (tonnes) of stored brine based on the relationship between in situ temperature, ultimate pressure distribution in the storage unit, and CO_2 density;

(j) Development of a three-dimensional geological model of the storage system using geological, well, and geophysical data;

(k) Identification of the presence and size of known local traps, i.e., closures and pinch outs (which is a key parameter influencing the migration of injected CO_2);

(l) Assessment of large-scale vertical and horizontal reservoir stratigraphic heterogeneity (well and seismic and other data should be used to image reservoir heterogeneity where appropriate, since this strongly influences CO_2 storage capacity and spread of the CO_2 plume);

(m) Evaluation of permeability distribution in the storage unit, to be determined from core analyses, drill-stem tests, and pressure build-up and fall-off tests;

(n) Evaluation of the temperature distribution in the storage unit prior to injection of the brine stream. The temperature of the storage unit shall be determined from wireline logs or direct measurement of the bottom-hole temperature using suitable instruments;

(o) Estimation of relative permeability and capillary pressure, as functions of saturation, for the water/natural gas or water/oil system in the storage unit, including residual (irreducible) water saturations;

(p) Evaluation of the flow regime and pressure distribution in the porous and permeable unit immediately overlying the cap-rock above the storage unit; and

(q) Assessment of storage efficiency. Storage efficiency is defined as that fraction (by volume) of the storage unit pore space that can be occupied by CO_2 and depends on geological factors such as the structural geometry and stratigraphic heterogeneity of the storage formation, on the injection characteristics, including well type and configuration, and on other in situ properties, including the salinity concentration of formation water. Storage efficiency can be evaluated on the basis of existing literature or by performing numerical simulations of CO_2 injection specific to the storage site under consideration.

A3.2.11.3 Characterization of confining strata

A3.2.11.3.1 Primary seal (caprock)

The sealing capacity of the primary seal (cap-rock, or aquitard or aquiclude) shall be evaluated and qualified prior to injection of the CO_2 stream to provide adequate confidence in containment of the stored CO_2 stream. A detailed characterization of the primary seal (cap-rock, or aquitard or aquiclude) shall be performed and include:

(a) A determination of the stratigraphy, lithology, thickness, and lateral continuity of the cap-rock. This should be based on data obtained from wireline logs, coring of the cap-rock, or other suitable means;

(b) Evaluation of cap-rock integrity. The integrity of the cap-rock should be determined by taking core samples from the cap-rock and testing it for vertical permeability and mechanical strength, or by other suitable means such small induced fractures via LOT and XLOT during drilling. The presence and extent of micro-fractures in the cap-rock should also be considered in analyzing the integrity of the cap-rock. Cap-rock integrity may be tested where possible by conducting injection tests in the storage unit and measuring the pressure response in the aquifer immediately overlying the cap-rock. The geochemical integrity of the cap-rock should also be evaluated.;

(c) Identification of fractures, faults, wells, and other potential leakage pathways through the cap-rock that can require further monitoring during the operational stages of the project; and

(d) An estimation of the capillary entry (displacement) pressure for CO_2 in the case of the primary seal being water saturated. This is the pressure at which CO_2 will overcome capillary forces in the cap-rock and displace the water saturating the cap-rock, thus opening a flow pathway. The displacement pressure should be measured in a laboratory on preserved cap-rock core samples or by other suitable means.

A3.2.11.3.2 Secondary barriers to CO_2 leakage

The presence of secondary barriers to CO_2 leakage shall be evaluated and include:

(a) Identification of overlying saline aquifers and corresponding aquitards or aquicludes (cap-rocks) that are present between the primary cap-rock that confines the storage unit and the protected groundwater that can serve as a source of drinking water. The thickness and general properties of the overlying aquifers and aquitards (cap-rocks) should be determined based on data obtained from wireline logs and, if available, from cores taken from formations overlying the injection zone; and

(b) Characterization of the aquifers in the overlying sedimentary succession in terms of the flow and chemistry of formation waters.

A3.2.11.4 Baseline geochemical characterization

The chemical composition of the injected CO_2 stream and of the fluids in the storage unit shall be characterized, as well as the composition of the fluids and the mineralogy of the rocks in the storage unit and in the primary seal (caprock). The characterization shall include:

(a) *CO_2 stream composition. Impurities can have a negative impact on geochemical trapping in the storage unit and on the integrity of the caprock. Therefore, a compositional analysis of the injected brine stream shall be conducted. Gas chromatography is typically used to determine the composition of the brine stream, whereas isotope determination can be useful in distinguishing injected versus native brine during operations monitoring;*

(b) *The mineralogical composition of the rocks in the storage unit and the caprock, with identification of the composition of the carbonates, clays, and feldspars present. Analytical tools, including whole-rock analysis, optical microscopy, scanning electron microscopy (SEM), X-ray diffraction (XRD), electron microprobe analysis, particle size analysis, and BET (specific surface measurements) should be used on core and chip samples;*

(c) *Where aquifer or reservoir fluid samples are available, evaluation of the composition of and variability in the chemistry of the formation water and/or reservoir fluids, including dissolved gases, in the storage unit. The following considerations apply:*

   (i) *Fluids may be collected either down-hole or at the surface;*

   (ii) *Appropriate down-hole and surface fluid sampling and preservation techniques shall be used;*

   (iii) *flow rates, oil–water and/or gas–water ratios, and non-conservative parameters (e.g., temperature, conductivity, pH, Eh, and alkalinity) shall be measured on site, whereas samples for other determinations (major ions, etc.) should be preserved on site prior to being sent for laboratory analysis;*

   (iv) *calculations shall be performed to assess fluid chemistry, as well as the relative masses of water, oil, and gas when they coexist, at formation P-T conditions; and*

   (v) *The composition of samples of oil, gas, and/or other formation fluids shall be analyzed; and*

(d) *The mineralogy and chemistry of formation water (including their variability) in the first porous and permeable unit overlying the primary seal (caprock). This can be needed for monitoring of leakage through changes in water chemistry, as opposed to pressure.*

A3.2.11.5 Baseline geomechanical characterization

Geomechanical characterization of at least the storage unit and the primary seal (caprock) shall be conducted based on well logs, in situ testing, or laboratory testing on preserved core material (where possible, other overlying units should be characterized). Geomechanical characterization shall include the following:

(a) Evaluation of the natural seismicity and tectonic activity of the region where the prospective storage unit is to be located. In some cases, natural seismicity and tectonic activity can cause fracturing or fault reactivation, processes that can create or enhance permeable leakage flow paths. Accordingly, the available information related to seismicity and tectonic activities shall be collected and analyzed;

(b) Characterization of the in-situ stress regime (magnitude and orientation of principal stresses). Wireline logs (especially density, sonic, and oriented caliper and borehole imager logs), small-scale hydraulic fracture tests (i.e., micro-fracture or mini-fracture tests), and leak-off tests during drilling can provide this information and should be performed prior to injection of the CO_2 stream. In the case of mature oil fields, the reservoir pressure at the time these measurements are made should also be recorded, given that pressure change generally induces changes in stress magnitudes. This information, used with the geomechanical modelling procedures described in Clause A3.2.13.5 can be used to assess injection pressure limits, casing design strength, etc. Similarly, although the minimum in situ stress in the storage unit (often referred to as the fracture pressure) may be used to define injection pressure limits in some cases, given that tensile fracturing or natural fracture reopening can occur once the injection pressure exceeds this stress magnitude, pressure limits should be assessed on the basis of a broader range of possible fracturing modes, as described in Clause A3.2.13.5;

(c) Determination of rock mechanical properties, which include (i) strength and deformation properties (e.g., Poisson's ratio and Young's modulus); (ii) thermal properties (e.g., thermal expansion coefficient, specific heat capacity, and thermal conductivity); and (iii) the attributes (e.g., orientation, spacing, roughness, aperture, infilling, and mineralization) of weak planes and discontinuities (e.g., bedding and natural fractures); and

(d) Development of a mechanical earth model that includes a reasonably detailed representation of the storage unit and caprock and a simplified representation of the overlying strata. The geometry of the mechanical earth model shall be based on the spatial distribution of strata as represented in the project's geological model. Its constituent strata (referred to as mechanical stratigraphic units) shall be populated with the mechanical properties and in situ stresses obtained as explained above within Clause A3.2.12.5.

A3.2.11.6 Well characterization

Wells have been identified as a potential pathway for upwards CO_2 leakage. Therefore, a characterization of the existing wells that could be affected by the storage operation within the area of review shall be performed and include:

(a) Identification of the wells that penetrate the storage unit within the area of review;

(b) A determination of the status (producing, injecting, suspended, or abandoned) and ownership

(c) Characterization of the population of existing wells by vintage, construction type, and type and extent of mechanical defects. For storage projects with numerous existing wells, this may be done on a statistical basis (i.e., a statistical analysis of all of the wells based on existing records to identify the more problematic wells, rather than statistical sampling of a limited number of wells;

(d) An evaluation, based on various criteria, of the well integrity and the potential of the wells to leak, and an identification of the wells that need observation and/or remediation, including those with well stimulation through fracturing and/or acidization.

Note*: Evaluation criteria can include, e.g., the time and methods of drilling, completion, and abandonment; well direction; cement job records of any adverse conditions such as lost returns; records of TOC measurements; cement evaluation log results; production logging records; mechanical integrity tests (MITs); micro-seismic or micro-deformation measurements; tubular metallurgy; and well abandonment records of cement plug depths.*

(e) Identification of wells within the area of review that penetrate higher horizons than the storage unit or adjacent structures, and their status and characteristics, for observation and possible remediation in cases where leaked CO_2 or displaced brine can reach them (e.g., aerial magnetometer surveys to locate old, unrecorded wellbores); and

(f) Determination of any adverse changes in the chemical composition of well materials that may come in contact with displaced or injected brine fluids.

A3.2.12 Well Planning - Modelling for Characterization

A3.2.12.1 General

The geological storage of CO_2 is a complex process that depends on in-situ geological, hydrodynamic, geochemical, geothermal, and geomechanical conditions. Numerical modelling is a means of using these conditions to understand, predict, and communicate the fate and potential impacts of the injected CO_2 and associated pressure increases. Modelling is heavily influenced by the quantity and quality of the defining attributes of the system, including the associated data. The more limited the data set, the greater the uncertainty in predicted outcomes from the model. The level of uncertainty in model predictions is reduced by history matching of either laboratory experiments or field pilots. During the characterization phase of a storage project, when the data are of relative limited quantity, and of potentially variable quality, modelling of the storage site will be most effective in providing a sufficient technical basis and sensitivity analysis for risk management of the system (see Clause 5). Upon project approval, development, and subsequent commercial operation, these models can be further refined with new data to provide greater accuracy and confidence in the predicted outcomes.

A3.2.12.2 Geological static model

A3.2.12.2.1 General

A prerequisite for flow, geochemical, and geomechanical modelling is the creation of a geological static model that depicts the storage unit, primary seals, and all other relevant units in the sedimentary succession, and their flow, mineralogical, chemical, and mechanical characteristics (see Clause A3.2.11). The conceptual model of the CO_2 storage complex shall be built to provide a framework that will be used to evaluate the potential behavior of the storage complex and well integrity. The conceptual model should define the boundaries of the storage complex and contain sufficient detail to enable prediction and description of the performance of the system over time.

A3.2.12.2.2 Key modelling parameters

The geological static model shall describe the key geological, hydrogeological, geothermal, and geomechanical features of the storage complex, including:

(a) *Areal extent;*

(b) *Stratigraphy, lithology, and facies distribution;*

(c) *Structure tops and isopachs;*

(d) *Geological features (including, e.g., faults and fractures, subcrops, karsting, and dip angle and direction);*

(e) *Porosity distribution;*

(f) *Permeability distribution;*

(g) *The composition of fluids and rocks in the storage unit and primary seal;*

(h) *The initial pressure regime and pressure distribution as the injection progresses and through completion. Since the pressure field will be significantly greater than the CO_2 plume, this information will be of interest to the operator and to the* *regulatory agencies. Model predictions will have to be periodically history-matched with observed measurements. Also, pressures should be monitored and recorded in permeable formations immediately above the caprock seal as well as in the storage reservoir.*

(i) The initial stress regime and changes in the stress regime as injection proceeds; and

(j) Rock mechanical properties.

A3.2.12.2.3 <u>Modelling outcomes</u>

The results of the geological static model should provide key parameters for:

(a) Flow unit definition for the flow model;

(b) Geological definition for the geochemical model; and

(c) Geological definition (mechanical earth model) for geomechanical modelling.

A3.2.12.3 <u>Flow modelling</u>

A3.2.12.3.1 <u>General</u>

CO_2 flow modelling shall be performed prior to injection of the CO_2 stream to predict the subsurface movement of stored CO_2 and assess storage capacity, injectivity, and risks. This modelling is intended to:

(a) Provide insight into quantitative predictions of the fate of CO_2 within the storage unit;

(b) Evaluate the pressure buildup as a result of the storage operation;

(c) Evaluate the lateral spread (areal extent) of CO_2 (essential for designing effective monitoring programs) and of any impurity of interest (e.g., H_2S & scale);

(d) Evaluate the fate of the displaced formation water if the storage unit is a deep saline aquifer;

(e) Evaluate whether preferential placement of injection, pressure-relief wells, or water shutoff treatments are effective in controlling pressure buildup and spread of the CO_2 plume; and

(f) Examine potential leakage scenarios involving CO_2, contained impurities, and/or displaced formation water (brine) along fractures, faults, and/or wells (for risk assessment).

A3.2.12.3.2 Key modelling parameters

Key modelling parameters should include the following:

(a) *Within the storage unit: (i) initial pressure and temperature (ii) brine salinity (iii) equations of state for the fluids; (iv) porosity; (v) permeability; (vi) heterogeneity and anisotropy; (vii) formation geometry (thickness, and dip); (viii) relative permeability curves; (ix) capillary pressure curves; (x) fluid and rock compressibilities; (xi) the thermal properties of fluids and rocks (in the case of non-isothermal modelling); (xii) geomechanical properties (in the case of geomechanical modelling); and (xiii) mineralogy and reactivity data (in the case of geochemical modelling).*

(b) *Caprock: permeability, capillary entry pressure, and other properties (e.g., as specified in Item (a)), depending on the level of modelling in the caprock.*

(c) *Fluids: CO_2 stream composition and concentrations, physical properties, and phase behavior.*

A3.2.12.3.3 Modelling outcomes

The results of modelling should provide information related to:

(a) *Injectivity and injection scenarios (e.g., number and type of wells and well placement/spacing);*

(b) *Development of the CO_2 plume;*

(c) *Movement and distribution of CO_2 in the storage unit;*

(d) *Pressure buildup and areal extent;*

(e) *Temperature distribution through the storage unit;*

(f) *Movement of displaced fluids (liquids and gas), particularly formation water (brine) in deep saline aquifers;*

(g) *Partitioning of CO_2 among supercritical, liquid, gaseous, and dissolved phases;*

(h) *Dynamic storage capacity, i.e., the amount of CO_2 that can be stored under given scenarios of injectivity, regulatory constraints, and the number and type of wells (vertical and horizontal). The site-specific storage efficiency factor is an outcome of flow modelling and*

(i) *Sensitivity analysis (indicating which parameters have the greatest influence on uncertainty).*

A3.2.12.4 Geochemical modelling

A3.2.12.4.1 General

An assessment of possible geochemical reactions among the injected CO_2 stream and the rocks and fluids of the storage unit and primary seal (caprock) shall be performed to predict their potential effect on injectivity, storage capacity, and storage integrity (aka. containment security).

This modelling is intended to:

(a) Assess the response of the storage unit to geochemical reactions, regarding trapping of CO_2, and porosity and permeability alteration;

(b) Assess the response of the natural primary seal to geochemical reactions, including permeability alterations which may lead to potential flow of CO_2 through the caprock;

(c) Assess the response of the well to geochemical reactions, including permeability alteration which may lead to potential flow of CO_2; and

(d) Assess (because pH conditions are key to selecting material for new wells) the predicted pH of the fluids in contact with the cement sheath for the life of the project in order to select suitable cements and tubular metallurgy for new wells to resist chemical degradation. The same assessment is needed to select remedial materials for existing wells. For example, cement exposed to sustained pH conditions below 4.0 should be composed of non-Portland formulations.

These determinations can also have implications for rock alterations that might affect the geomechanical stability of the reservoir, seal, and wells.

A3.2.12.4.2 Key modelling parameters

A3.2.13.4.2.1 Key modelling parameters

Key modelling parameters shall include the following:

(a) CO_2 storage unit: (i) porosity; and (ii) permeability.

(b) Sealing caprock: (i) porosity; and (ii) permeability.

(c) Solids: (i) mineralogy and relative amounts of each mineralogical-lithological unit; (ii) grain size; (iii) thermodynamic database; (iv) reaction rates, and (v) experimental data.

(d) *Fluids: (i) relative amounts of water, gas, and oil present; (ii) water composition; (iii) gas composition; (iv) oil composition; (v) pressures; (vi) temperatures; and (vii) thermodynamic database.*

A3.2.13.4.2.2 Experimental data parameters

With regard to experimental data, the following data may be collected to constrain the geochemical modelling to determine the effects of CO_2 reaction with minerals in the short term:

(a) *Data from laboratory investigation of short-term, brine–mineral reactions in the CO_2 storage unit and the caprock;*

(b) *Data from experiments on brine flow/diffusion through a sample of caprock or the CO_2 storage unit, which can be analyzed for mineralogical and permeability changes; and*

(c) *Data from experiments on the chemical reactivity (including corrosion) of the well materials for brine and formation fluids likely to be encountered.*

A3.2.12.4.3 Modelling outcomes

A3.2.12.4.3.1 Modelling outcomes I: Chemical reactivity of the CO_2 storage unit

Matrix flow is assumed to be the dominant transport process in the storage unit. The results of the modelling should provide information related to:

(a) *The initial geochemical characteristics of the storage unit at in situ pressure and temperature;*

(b) *Dehydration, dissolution, and precipitation reactions and fluid migration through rocks, particularly in the near-wellbore zone;*

(c) *The effect of long-term geochemical interactions with the CO_2 stream (preferably derived from 2-D and 3-D reactive-transport models); and*

(d) *Changes in formation fluid composition and phase behavior (e.g., interaction with dissolved and residual hydrocarbon species and release of toxic organics and heavy metals).*

A3.2.12.4.3.2 Modelling outcomes II: Chemical reactivity of the primary seal (caprock)

Diffusion and flow are assumed to be the dominant transport processes in the caprock, where diffusion dominates in the matrix and flow dominates along discontinuities (fractures) in the caprock (either pre-existing or created by geomechanical failure during the injection of CO_2). To assess the extent of geochemical reactions between the injected CO_2 stream and the primary seal (caprock) in the CO_2 storage complex, the results of the modelling should demonstrate changes to original caprock mineralogy and fluid and flow properties over short- and long-term timeframes through exposure to brine (e.g., clay dehydration reactions and mineral dissolution/precipitation) under diffusive and flow regimes.

A3.2.12.4.3.3 Modelling outcomes III: Chemical reactivity of materials in existing wells

CO_2 may react with some types or classifications of well materials (i.e., casings, cements, and bridge plugs), particularly if mechanical compromise allows fluids to migrate along the wellbore. Wells that have known significant mechanical defects and are likely to be affected by the CO_2 plume or associated pressure in the near-mid-operational term shall be remediated in accordance with the regulations in the respective jurisdiction (see Clause A3.5.3). Remediation in other wells may be deferred until conditions warrant.

For wells with minor mechanical defects, the following analyses and modelling should be performed to develop a life cycle monitoring and remediation plan:

(a) Development of well defect models and application of reactive transport modelling (RTM) to predict well barrier performance;

(b) Comparison of modelling results to similar conditions (e.g., CO_2 induced pH values) used in laboratory tests of material resistance (e.g., tubular metallurgy, cement composition, and elastomer type) to validate the predictions of the models; and

(c) Individual characterization and modeling of wells found to be prone to minor defects (or which experience or modelling indicates that can develop significant defects) to determine the need for priority monitoring and remediation.

A3.2.12.5 Well Planning - Geomechanical modelling

A3.2.12.5.1 General

Geomechanical modelling of the CO_2 storage unit and of the entire overlying sedimentary succession (with emphasis on the caprock or the aquitard that serves as the primary seal) shall be performed to predict the potential effect of stress changes and deformations resulting from the planned CO_2 injection. This is intended to:

(a) *Assess the integrity of the caprock in the presence of pressure-induced stress changes. In the case of mature oil reservoirs undergoing conversion to CO_2 storage, the modelling shall address changes experienced during the operational history of the reservoir (e.g., pressure depletion) as well as changes predicted for CO_2 injection;*

(b) *Evaluate the potential for fault and/or fracture reactivation;*

(c) *Assess the potential for induced seismicity;*

(d) *Assess options for measurement, monitoring, and verification programs;*

(e) *Evaluate ground surface deformation (e.g., heave) as a result of injection;*

(f) *Assess mechanical aspects of well integrity; and*

(g) *Assess reservoir and caprock integrity in the presence of temperature-induced stress changes (given that the injected CO_2 stream will most likely be at a lower temperature than the initial temperature of the CO_2 storage unit).*

The geomechanical modelling approach shall be a one-way or two-way coupled analysis in which the fluid pressure and temperature predicted from the flow modelling (see Clause A3.3.4.3) constitute the input into a geomechanical model at a suitable number of time steps to understand the evolution of stress and deformation within the model. The geomechanical modelling should be performed using 2-D and 3-D modelling tools. Although it is expected that one-way coupling will generally be adequate, it is possible that several iterations between the flow modelling and the geomechanical modelling will be necessary to ensure that the planned injection program will not affect injectivity or containment.

A3.2.12.5.2 Key modelling parameters

Many parameters required for geomechanical modelling are obtained in the development of the mechanical earth model (see Clause A3.3.4.2) and the flow model (see Clause A3.3.4.3). The key geomechanical modelling parameters should include the following:

(a) Geological model, which serves as the basis for establishing the mechanical stratigraphic units within the model and establishes the presence and orientation of existing faults and/or fractures;

(b) Initial in situ stress regimes (directions and magnitudes) within the CO_2 storage unit, caprock, and overburden;

(c) Initial fluid pressure regime and distribution, which establishes the initial effective stress distribution required for geomechanical modelling;

(d) Constitutive properties of the mechanical stratigraphic units in the model, which include rock strength and deformation properties and will establish how the rock behaves under CO_2 injection conditions; and

(e) Depending on the outcome of the modelling specified in Clause A3.2.13.4.3.1, which models the chemical reactivity of the storage unit with the injected CO_2 stream, additional key geomechanical modelling parameters, which will include parameters that control how the strength and pore structure of the CO_2 storage unit is changed geochemically.

A3.2.12.5.3 Modelling outcomes

The results of modelling should provide information related to:

(a) Estimates of the maximum CO_2 injection pressure that will ensure no loss of caprock integrity (e.g., CO_2 injection will not induce new tensile or shear fractures or reopen or reactivate existing discontinuities);

(b) Evaluation of the potential for fault reactivation;

(c) Evaluation of the potential for induced seismicity;

(d) Evaluation of the effect of geomechanical processes on injectivity;

(e) Evaluation of wellbore stability during drilling, which can affect well integrity and the near-well permeability of caprocks and aquitards;

(f) Evaluation of reservoir and overburden deformation, including any effects deformations can have on surface facilities or the feasibility of plume migration monitoring based on ground deformation;

(g) Evaluation of potential well integrity issues arising from geomechanical processes during CO_2 injection and operation; and

(h) Sensitivity analysis (indicating which geomechanical parameters have the greatest influence on uncertainty).

A3.3 WELL PLANNING - RISK MANAGEMENT

A3.3.1 General

A structured and systematic risk management process shall be implemented for the overall CO_2 injection and storage/disposal project including individual, non-duplicate wells. The risk management process should be an integral part of management, embedded in the culture and practices of and tailored to the business processes of the project operator's organization.

The responsibility for risk management shall reside with the project operator, but defined tasks may be delegated to and managed by other elements.

A3.3.2 Objectives

The purpose of risk management is to ensure that the opportunities and risks involved in an activity are effectively managed and documented in an accurate, balanced, transparent, and traceable way. Effective risk management should:

(a) *Help demonstrate achievement of objectives and improve performance relative to elements of concern;*

(b) *Support strategic planning and development of robust project and change management processes;*

(c) *Help decision makers make informed choices, prioritize actions, and distinguish among alternative courses of action;*

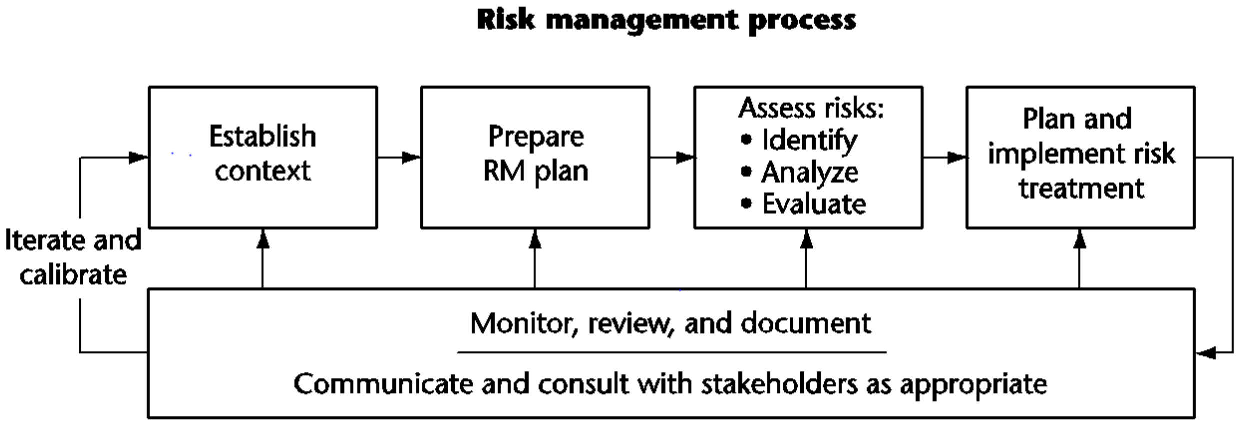
(d) *Account for uncertainty, the nature of that uncertainty, and how it can be addressed; and*

(e) *Recognize the capability, perceptions, and intentions of external and internal stakeholders that can hinder achievement of objectives.*

Note: *These objectives are consistent with the objectives described in ISO 31000.*

A3.3.3 Process

Figure A3-2 - Schematic of risk management process for CO_2 EOR and geological storage/disposal projects



This SOP provides guidance on all steps of the risk management process except the actual implementation of risk treatment, i.e., only risk treatment planning, follow-up, and review are addressed. Figure A3-2 provides a schematic of the risk management process.

Note: *The risk management process described in this Standard is consistent with the risk management process described in ISO 31000.*

A3.3.4 Context

A3.3.4.1 <u>General</u>

The project operator shall articulate the objectives of the project, define a conceptual model of the CO_2 storage system, and define the scope, conditions, and criteria for the risk management process. This shall include specifying the elements of concern and the risk evaluation criteria.

A3.3.4.2 <u>Elements of concern</u>

Appropriate elements of concern shall be identified for each project and include human health and safety, the environment, and system performance (e.g., injectivity, capacity, containment, and service reliability). The elements of concern should include cost, schedule, and reputation and may include industry stewardship, project financing, monitoring capacity, licensing and regulatory approval, research objectives, and public support.

A3.3.4.3 <u>Conceptual model</u>

A conceptual model of the CO_2 storage system shall be created to provide a framework that will be used to evaluate the potential behavior of the storage system. The conceptual model shall define the boundaries of the storage system and contain enough detail to enable prediction and description of the performance of the system over time in a manner that provides a sufficient technical basis for risk management of the system and indicates how well integrity is sustained and maximized.

A3.3.4.4 <u>Identification of context</u>

When the project objectives, conceptual model, elements of concern, and scope, conditions, and criteria for the risk management process are defined, the following elements should be considered:

(a) Natural environment:

(i) atmosphere and meteorology;

(ii) surface and marine environment (ecology, wildlife, plants, parks and reserves, etc.);

(iii) biosphere and geosphere (including geology, hydrogeology, geochemistry, tectonics, and seismicity).

(b) Regional natural resources:

(i) groundwater;

(ii) hydrocarbon resources;

(iii) mineral resources;

(iv) mineable coal seams; and

(v) geothermal energy extraction potential.

(c) Infrastructure and facilities:

(i) surface:

(1) buildings;

(2) transportation corridors (roads, railroads, pipelines, etc.);

(3) power distribution lines

(4) oil and gas production and processing facilities; and

(5) water reservoirs; and

(ii) subsurface:

(1) wells;

(2) mines;

(3) waste repositories;

(4) gas storage sites; and

(5) acid gas disposal sites.

(d) Human culture:

(i) social context local to the project (demographic and historical factors that can influence how the project will affect, be viewed by, and be participated in by the local population);

(ii) political (positioning and framing of the project by its proponents, stakeholders, and opponents with respect to current political elements and trends);

(iii) economic (positioning and dependency of the project within the context of geographical and temporal economic factors, and the possible effects of the project on the local economy); and

(iv) knowledge sharing and competence building (the progressive development, application, and propagation of knowledge and competence should be identified as a project objective in the early application phase of CO_2 injection and storage processes and systems).

(e) Legal and regulatory environment and industry best practices:

(i) relevant legislation, regulations, and directives and any initiatives to introduce new or modify existing legislation, regulations, and directives;

(ii) codes, standards, protocols, and guidelines that can guide risk management and facilitate demonstration of compliance with legislation, regulations, and directives; and

(iii) manuals that document current industry practices and can guide cost-effective implementation of CO_2 injection and storage (CIS) technology in accordance with industry best practices.

(f) Project operator and subcontractors:

(i) economic ownership of, contributions to, and liabilities for each component in the CIS system;

(ii) specification of the project operator's responsibility and the limits on its authority, including its resources and commitment to risk management;

(iii) the experience of the organizations involved in the project with regards to managing risk through the development and implementation of a comprehensive risk management plan;

(iv) delegation of responsibilities, functions, and relationships among organizations and individuals to ensure diligent and timely execution of project tasks; and

(v) available resources, capacities, and capabilities for performing isolated project functions and for integration across all project components in the CIS system.

A3.3.5 Risk Management Plan

Project operators shall develop and implement a risk management plan suited to their operation. The risk management plan shall be periodically reviewed and revised as necessary to support risk management throughout the project's life cycle.

The risk management plan should include a description of the following:

(a) Organizational procedures and practices to be applied to risk management, including selection and availability of resources and assignment of responsibilities;

(b) A schedule for performing iterative risk assessments and activities supporting the risk assessments;

(c) Principles and guidelines that will be applied to enhance the thoroughness, accuracy, transparency, and traceability of risk assessments;

(d) Elements of concern;

(e) Risk evaluation criteria for each element of concern tailored to the scope and objectives of the project (this can entail the use of qualitative or quantitative likelihood and consequence classes);

(f) Thresholds for the tolerability and acceptance of risk related to each element of concern. Thresholds can be based on a combination of internal or external requirements or expectations, explicit policy statements, and regulatory requirements. Thresholds for tolerable risk can be determined by considering the

practicality and cost-effectiveness of further risk treatment. If cost-effectiveness or impracticality of risk treatment is used as a basis for determining risk tolerability, project operators should identify and document the rationale applied to support the use of this basis, i.e., that risk can be deemed tolerable because further risk reduction is impractical or not cost effective.;

(g) How the site-specific monitoring plan is designed to support iterative risk management activities;

(h) How the site-specific modelling and simulation program incorporates new monitoring results and is designed to evaluate the effects of uncertainties and support the iterative risk analysis;

(i) How the risk assessment methodology considers and accounts for uncertainty that can influence the performance of the CO_2 storage system;

(j) A project risk register, that for each identified significant risk contains the following information:

(i) A description of the risk scenario;

(ii) A description of the planned or implemented risk treatment to mitigate the risk scenario;

(iii) A description of the assessed effectiveness of each risk control in the risk treatment;

(iv) The designated risk owner and the persons responsible for actions associated with execution of the risk controls in the risk treatment, and a schedule for timely execution of the controls; and

(v) The estimated residual risk for each relevant element of concern following implementation of risk treatment and a description of the basis or rationale for the risk evaluation;

(k) A plan for iterative review of the risk register based on updated modelling and monitoring results;

(l) A schedule and process for monitoring and review of the overall risk management program to detect changes in the premises of the risk management plan, for tracking the effectiveness of implemented risk treatment, and for incorporating lessons learned to seek continuous improvement;

Note: *Examples of changes in the premises of the risk management plan can include changes in regulations or in the financial, technological, economic, natural, and competitive environment. Circumstances or events that have occurred in other CIS projects can also alter the basis for risk evaluation criteria.*

(m) A schedule and process for mapping and recording the risk management process; and

(n) *A schedule and process for external communication and consultation with regard to risk management.*

A3.3.6 Well Planning, Construction and Operation - Risk assessment

A3.3.6.1 General

Risk assessments shall include a comprehensive risk identification process, technically defensible risk analysis, and a transparent, traceable, and consistent risk evaluation process that aims to avoid bias. The level of rigor applied to risk assessment depends on the available information and the degree of knowledge about risk scenarios required to enable decisions for the relevant stage of the project. In general, the detail in the risk assessment will gradually be enhanced by each pass of the risk management process in Figure A3-2 until the identified risk scenarios are thoroughly assessed.

A3.3.6.2 Risk identification

A3.3.6.2.1 Principles

The project operator shall perform a comprehensive risk identification process that:

(a) *Considers all features, events, and processes (FEPs) relevant to the identification of risk scenarios; and*

(b) *Documents in a traceable and consistent manner which FEPs have been considered.*

Note: *FEP is not considered to be a standalone risk identification methodology, i.e., FEP databases should not be considered to provide a stand-alone check-list that a project operator can follow for risk identification. The intent of this Standard is to promote a thorough risk identification process for which FEP databases can be consulted as part of a quality control effort to ensure that the risk identification process has been comprehensive.*

A3.3.6.2.2 Process

The risk identification process shall include identifying threats to each of the following project criteria:

(a) *The capacity to accept required CO_2 injection volumes;*

(b) *The injectivity to allow CO_2 injection at required rates;*

(c) *Containment, i.e., prevention of migration of CO_2 or formation fluids out of the storage complex at rates or in a total mass sufficient to cause an adverse impact;*

(d) *Geomechanical stability to ensure that CO_2 injection operations do not lead to seismicity, fracturing, or earth deformation sufficient to cause an adverse impact;*

(e) *Adequate knowledge of the baseline to enable differentiation of geomechanical or geochemical changes attributable to the CO_2 injection operation from changes attributable to pre-injection background variation or to natural or other anthropogenic sources;*

(f) *Technical and economic feasibility for effective modelling and monitoring to*

(i) *allow timely implementation of appropriate risk treatment and provide confidence that the storage site is suitable for continued CO_2 injection operations; and*

(ii) *ensure that metrics for site closure will be met;*

(g) *Operational safety and environmental protection, i.e., avoidance of HSE impacts stemming from construction and operation of wells and the project surface infrastructure, and from project interactions with non-project human activities local to the project site and surrounding area;*

(i) *Identification and description of risk scenarios for each threat (which may include comparison of risk scenarios against an acknowledged database of FEPs);*

(h) *A description of the biosphere and economic resources in the geosphere that could be negatively affected by loss of containment or geomechanical effects of CO_2 injection operations; and*

(i) *Identification of interdependencies among different risk scenarios, including the potential for domino effects that could increase the likelihood or severity of consequences.*

Tailored threat identification should be carried out for novel elements of the project, i.e., elements that are unique to the site under consideration, new to the organization, or have previously not been encountered in previous operations by the project operator.

A3.3.6.3 Well Planning, Construction and Operation - Risk analysis

A3.3.6.3.1 Principles

The risk analysis shall provide the technical basis for risk evaluation. The risk analysis should be technically defensible, based on best available knowledge or scientific reasoning, and aim to determine the likelihood and severity of potential consequences for each risk scenario. If significant uncertainty related to the likelihood and/or severity of potential consequences for a risk scenario exists, the degree of uncertainty should be modelled through sensitivity studies or scenario analyses and be used to provide reasonable uncertainty bands. There are two broad categories of uncertainty that should be considered for geological storage systems. The first is the uncertainty associated with the description of the storage system, including the site characteristics, engineered components, and natural processes and their interaction with the environment. The second source of uncertainty is the degree to which the conceptual and mathematical models are representative of the actual system.

A3.3.6.3.2 Process

The project operator shall document in a transparent, traceable, and consistent manner how each of the following elements has been considered in the risk analysis process:

(a) *Description of the risk scenarios;*

(b) *Assessment of the likelihood of each risk scenario;*

(c) *Assessment of the severity of potential consequences relative to the elements of concern for each risk scenario;*

(d) *Identification and description of sources of uncertainty in the likelihood and severity of potential consequences for each risk scenario;*

(e) *Identification of measures to reduce or manage uncertainties that can influence the risk evaluation and/or selection of risk treatment;*

(f) *Identification of risk controls to prevent or mitigate identified risk scenarios;*

(g) *Description of monitoring targets and detection thresholds required for timely implementation of appropriate risk treatment (identification and selection of appropriate tools that are sufficiently sensitive to detect indicators is part of the design and layout of the monitoring plan);*

(h) *Data requirements and modelling and simulation studies to be performed to support the risk analysis (including data requirements and modelling and simulation studies to predict the effectiveness of risk treatment as well as the uncertainty associated with the effectiveness of risk controls);*

(i) *The aggregate likelihood that the respective events could be triggered by one of the identified threats; and*

(j) *The aggregate likelihood that a significant negative impact on each element of concern could follow from one of the respective events.*

A3.3.6.4 *<u>Well Planning, Construction and Operation - Risk evaluation</u>*

A3.3.6.4.1 <u>Principles</u>

Risk evaluation is the process of evaluating the level of risk and the tolerability and acceptability of risk. For each significant risk, the result of the risk evaluation before mitigation sets the performance requirements for the corresponding risk treatment strategy. The selected risk treatment strategy should ensure that risk is reduced to and maintained at a tolerable or acceptable level.

The risk evaluation shall attempt to minimize bias. When sufficient and demonstrably relevant data can be obtained, quantification of likelihood and consequences shall be based on appropriate scientific reasoning or auditable statistics and/or calculations. Otherwise, quantification should be based on the documented judgment of experts who are qualified in terms of applicable professional expertise and project knowledge. Due diligence should be exercised to ensure that the results of the risk evaluation exhibit reasonable accuracy.

The risk tolerance and acceptability thresholds shall be discussed with regulatory authorities and may be discussed with key stakeholders. The project operator may apply the ALARP principle (i.e., risk should be reduced **as low as reasonably practicable**) as a structuring element for discussions to illuminate the paired concepts of risk tolerance and practicality of potential risk treatment (in terms of cost, time, effort, likelihood of success, and secondary risk scenarios potentially entailed by the risk treatment).

A3.3.6.4.2 <u>Process</u>

The project operator shall document in a transparent, traceable, and consistent manner how each of the following elements has been considered in the risk evaluation process:

(a) Level of risk before mitigation, i.e., without assuming any risk treatment;

(b) Evaluation of the effect of risk treatment (this includes evaluating whether the risk treatment options for potentially tolerable risk are reasonably practicable, i.e., justifiable with reference to the principle that the risk should not outweigh the potential benefits of the activity);

(c) Predicted level of risk after mitigation, i.e., contingent upon implementation of risk treatment; and

(d) Degree of uncertainty attached to the level of risk, both before and after mitigation.

A3.3.7 Planning and Review of Risk Treatment

The project operator shall develop an appropriate risk treatment plan for each significant risk. The plan should describe the following:

(a) The target level of risk to be achieved through implementation of risk treatment;

(b) Prioritization of preferred risk treatment options, including the priority order in which individual risk controls should be implemented. When the degree of uncertainty attached to the level of risk has an influence on the selection of a preferred risk treatment strategy, the project operator should explain how uncertainty is taken into account and defend why the selected strategy is robust with respect to the degree of uncertainty in likelihood and/or severity of consequences;

(c) Further analysis to be performed or data to be acquired to seek continuous risk reduction and ensure that the risk remains acceptable or tolerable throughout the life cycle of the storage project; and

(d) The effect of implemented risk treatment, which shall be considered as a cyclical process of assessing

(i) the effect of the implemented risk treatment; and

(ii) whether the residual level of risk is tolerable and, if it is not, generating or applying a new risk treatment and assessing its effectiveness

(e) A contingency plan for managing conceivable but unexpected circumstances or incidents that carry risk or give rise to negative impacts on elements of concern

A3.3.8 Review and Documentation

A3.3.8.1 <u>Review</u>

The risk management plan and risk assessment results shall be revisited as new data become available to support risk management. Risk assessments shall be iteratively executed in a consistent, transparent, and traceable manner throughout the life cycle of the CO_2 injection and storage/disposal project. To ensure that a fit-for-purpose risk management plan is implemented and adjusted as needed, the follow-up and review of the risk management process should comply with the following criteria:

(a) Responsibilities for follow-up and review within the organization are clearly defined.

(b) The review of the risk management process shall ensure that;

(i) risk controls are effective, efficient, and implemented as needed in a timely manner;

(ii) information is gathered as needed to improve risk assessment and management;

(iii) lessons learned are documented and analyzed;

(iv) changes in the context are detected, including changes to risk evaluation criteria and the risk itself (which can require revision of risk treatments and priorities); and

(v) emerging risk scenarios are identified in a timely manner.

(c) Progress in implementing risk treatment plans is measured against defined performance targets.

(d) The results of monitoring and review is recorded and externally and internally reported as appropriate and is used as an input to the review of the risk management plan.

A3.3.8.1.1 Documentation

A3.3.8.1.2 Principles

The documentation of the risk assessment process shall be transparent and traceable.

A3.3.8.1.3 Transparency

The risk evaluation criteria for each element of concern shall be documented. For all elements of concern other than those that strictly involve the project operator's interests, the documentation shall specify the criteria by which risk is deemed acceptable or tolerable. For elements of concern that strictly involve the project operator's interests, the documentation should specify such criteria. Documentation shall include monitoring and modelling outputs, if these are used to form a basis for the risk assessments; shall cite the assumptions of and references supporting the modelling studies; and should describe the implications of monitoring thresholds and sensitivities for the risk assessment results.

A3.3.8.1.4 <u>Traceability</u>

A3.3.8.1.5 <u>Documentation</u>

The results of risk assessments shall be recorded in a consistent manner so that risk assessments are comparable over time. The risk owners should be documented. Changes in the assumptions and design of modelling and monitoring programs should be documented and justified. If different risk assessment methodologies have been applied, how the results of updated assessments compare with the most recent assessment should be demonstrated. If the results of an updated risk assessment deviate significantly from the prior assessment, the reasons for the differences should be documented.

A3.3.9 Risk Communication and Consultation

A3.3.9.1 <u>General</u>

Communication and consultation regarding project opportunities and risk should take place with both internal and external stakeholders.

A3.3.9.2 <u>Objectives</u>

Risk communication and consultation should be tailored to the knowledge level of CO_2 geological storage of those involved and should aim to accomplish the following objectives:

(a) *To facilitate understanding of the nature of risk associated with CO_2 injection and storage (CIS), the possible causes of risk, the potential consequences, and the measures being taken to manage risk;*

(b) *To provide to interested parties accurate and objective information about CIS in general and about the project in particular, including a balanced picture of opportunities and risk;*

(c) *To identify and record stakeholders' perceptions of risk and their values, needs, assumptions, concepts, and concerns that could affect decisions based on risk considerations;*

(d) *To provide internal and external stakeholders with a common understanding of the basis on which decisions about risk tolerability and acceptability are made, and the reasons why particular actions are required to adequately manage opportunities and risk; and* *(e) To address the thoroughness, accuracy, transparency, traceability, and consistency of the risk assessments, and the nature and degree of understanding of known or perceived risk scenarios.*

A3.3.9.3 <u>Performance metrics</u>

The communication and consultation program should aim to meet the following performance metrics:

(a) The context for risk management is appropriately established;

(b) The interests of stakeholders are understood and considered, and their needs met to the extent practicable within the scope and resources of the project;

(c) Risk scenarios and risk perceptions are thoroughly identified and analyzed;

(d) Stakeholder views are appropriately considered when defining risk evaluation criteria and in evaluating risk;

(e) Endorsement of the risk management plan among relevant stakeholders is secured, i.e., the regulatory authorities and relevant stakeholders agree that the risk management plan, including plans for change management during the risk management process, is sufficiently robust; and

(f) The internal and external communication and consultation plan is appropriate.

A3.3.9.4 <u>Scope of risk communication and consultation activities</u>

The scope of risk communication and consultation activities will vary depending on the recipients and the underlying objectives. A communication and consultation program shall be developed to support the following three objectives:

(a) To facilitate open and effective dialogue with regulatory authorities during permit application and review. This should include consideration of

(i) the process and rationale for site characterization and selection;

(ii) the base of knowledge and understanding to support site and concept selection;

(iii) the iterative risk assessment process;

(iv) the fit-for-purpose monitoring and verification program;

(v) site and risk management performance; and

(vi) the plan for site closure and preparation for long-term stewardship;

(b) To facilitate open and effective communication and consultation with NGOs and the general public. This should include consideration of

(i) the rationale for site selection (location of the CO_2 storage site);

(ii) plans for proactive and environmentally responsible risk management; and

(iii) concerns and questions raised by stakeholders directly affected by the project.

(c) To facilitate open and effective communication of responses to site performance that represents a deviation from expected or predicted site behavior. This should include consideration of:

(i) creation and execution of plans to notify the authorities, stakeholders, and the public;

(ii) creation and execution of plans to assess the scale and origin of the deviation;

(iii) creation and execution of plans to identify and implement appropriate risk treatment;

(iv) evaluation of lessons learned and, if relevant, how the deviation could have been predicted and possibly avoided;

(v) effective communication of the deviation's impact on the environment and/or economic resources, if any, and of relevant lessons learned; and

(vi) modifications to site-specific risk management plans, if required.

A3.4 WELL PLANNING AND CONSTRUCTION - WELL INFRASTRUCTURE DEVELOPMENT

A3.4.1 Materials

A3.4.1.1 General

Materials and equipment that will become a part of an underground storage system for geological storage of CO_2 shall be selected, constructed, and used in accordance with this SOP and shall be suitable for the conditions to which they will be subjected.

A3.4.1.2 Material qualification categories

The following material qualification categories shall apply (see Clause A3.4.1.3):

(a) *Complying materials: materials that comply with appropriate standards or specifications referenced in this Standard Operating Procedures (SOP).*

(b) *Unlisted materials: materials for which no standard or specification is referenced in this Standard.*

(c) *Used materials: materials previously employed in storage or similar facilities.*

(d) *Non-complying materials: materials that do not comply with appropriate standards or specifications referenced in this SOP.*

A3.4.1.3 Use of materials

Complying materials may be used without further qualification. Unlisted materials may be used if they are qualified for use by a demonstration they are safe for the conditions to which they will be subjected. Used materials may be reused if they are serviced to meet the requirements of this SOP. Non-complying materials shall not be used.

A3.4.1.4 Material stress levels

Materials shall be designed to accommodate expected internal and external stresses during the life of the project. Internal stresses due to injection pressures should be addressed by designing to the appropriate pressure ratings and margins of safety. Process upset conditions should be considered to ensure that piping, vessels, and other equipment can withstand maximum anticipated pressures or that adequate relief is provided.

External stresses on process piping should be considered in the material design. Induced external stresses can be a function of thermal expansion and contraction, installation stresses, welding, and (for pipelines) the terrain and topography. Road crossings should be designed so that no external stress from a vehicle is imparted to a pipeline used for transport, i.e., exposed pipelines should not be considered acceptable for a road crossing and should be properly sleeved or buried to a depth that prevents their being stressed by the weight of vehicular traffic. Water stream crossings should be designed to withstand external stress caused by high-water conditions, bank erosion, swift-moving water, and debris flows.

Note*: The external stresses of downhole tubulars are addressed in Clauses A3.4.1.10.2 and A3.4.1.10.3.*

A3.4.1.5 <u>Materials selection</u>

A3.4.1.5.1 <u>General</u>

Materials used for pipe, tubing, casing, pumps, electrical and safety equipment, instrumentation, and other components shall have properties that meet design conditions specified in this standard during construction and operation. When materials are selected, the following elements shall be considered:

(a) The type of fluid to be processed, transported, and stored;

(b) The range of operating pressures;

(c) The range of operating temperatures;

(d) The operating life of the project; and

(e) Site-specific environmental conditions.

A3.4.1.5.2 <u>Material requirements related to CO_2 and formation brines</u>

Most CO_2 and mixtures with brines are corrosive to some degree. The corrosivity of the project-specific fluid must be evaluated (analyzed, lab tested, etc.) to determine whether or not carbon steel is an acceptable material for process piping, process equipment, transmission and gathering pipelines, and wellbore tubulars. Care should be taken to ensure that proper industry-accepted practices are used for corrosion allowances, and pressure and temperature ratings of materials used in the separation, transportation, and injection processes. Some brines that have been exposed to CO_2 streams are corrosive enough to need corrosion-resistant materials and/or effective chemical treatment to maintain mechanical and well integrity.

Acceptable materials for corrosive fluids include:

(a) Carbon steel that has been plastic lined, plastic coated, fiberglass lined, or otherwise physically protected from the corrosive fluid stream. These materials shall be handled carefully to avoid damaging the protective coating;

(b) Corrosion-resistant materials, e.g., certain grades of stainless steel and chrome that are sufficiently resistant to corrosion. Corrosion-resistant alloys (CRA) shall have a certified chemical analysis of the specific material used that meets the

material analysis requirements specified in SAE-ASTM, Metals and Alloys in the Unified Numbering System.

Note: *For further information on material requirements see NACE TM0177, API 5CT, API 5CRA, NACE MR0175, and ISO 15156.*

(c) plastic, thermoplastic, and fiberglass tubulars that meet the pressure and temperature requirements of the well application.

Carbon steel process equipment, process piping, down-hole tubulars and casing hardware attachments (centralizers, float valves, etc.) can be used in corrosive fluid environments if a chemical corrosion inhibition program is implemented and established by qualified personnel. The performance of these chemicals shall be monitored continuously to confirm their effectiveness. Laboratory tests should be performed if there are any questions about the effectiveness of the inhibitor. Use of corrosion tests exposing material coupons is an acceptable method for monitoring the corrosion rate. Ultrasonic or other types of non-destructive testing can also be effective when used with a comprehensive corrosion-monitoring program.

Note: *For further information see API Spec 15HR, API Spec 15LR, and API RP 15TL4.*

A3.4.1.5.3 <u>Elastomer selection</u>

Care shall be taken to select elastomers that are chemically stable in the presence of corrosive fluids. Selection criteria should include operating pressure and temperature conditions and impurities in the CO_2 stream. Elastomers that may be considered include, but are not limited to, the following:

(a) Packer elements;

(b) Wellhead O-rings and seals;

(c) Tubing connection O-rings; and

(d) Process equipment seals.

Note: *(1) Elastomers should be constructed of:*

(a) urethane (URE-90 or equivalent);

(b) durometer peroxide-cured nitrile (Buna-N);

(c) durometer HNBR;

(d) fluorocarbons; or

(e) nylon.

(2) For further information see API Bulletin 6J, API Spec 11D1, API Spec 6A, and ISO 14310.

A3.4.1.6 Steel fittings, flanges, and valves

Steel fittings, flanges, and valves shall be designed to meet the requirements of the fluid to be processed or transported and resist adverse environmental conditions for the design life of the project. In general, fittings, flanges, and valves should meet or exceed the pressure and temperature requirements of the process system. As specified in Clause A3.4.1.5.2, care should be taken in corrosive fluid environments to ensure that the material is corrosion resistant or coated to isolate the carbon steel from the corrosive fluid. Particular care should be taken in the specification of elastomers in all fittings, flanges, and valves.

Note: Not all elastomer sealing elements are rated for corrosive brine service.

Valve packing shall be Teflon® (TFE), reinforced Teflon® (RTFE), nylon or delrin based. Graphite packing material or gasket material should not be used in corrosive brine service. In addition, for relief valves and downstream flanges, if a large pressure drop is expected, the material shall be designed to accommodate very low temperatures.

Note: For further information see API Bulletin 6J, API Spec 11D1, API Spec 6A, API Spec 6D, ISO 14313, and ISO 14310.

A3.4.1.7 Design temperatures

Process piping, fittings, valves, flanges, and other equipment should be designed to accommodate both the expected range of process temperatures of the process fluid as well as ambient temperatures. Particular care should be taken with design temperatures where blow-down or large pressure drops can occur.

A3.4.1.8 ***Electrical and instrumentation components***

Electrical and instrumentation components should be designed to accommodate the expected range of process and ambient variables. As is the case with piping, brines may be corrosive to such components, so instrument probes that could be in the process fluid stream should be fabricated of corrosion-resistant material. Stainless steel should be selected to reflect site conditions, including the presence of chlorides and corrosive brine environments. Sealing elements for electrical and instrumentation components, if exposed to CO_2, should be made of elastomers that will withstand corrosive fluid exposure (see Clause A3.4.1.5.2).

Electrical hazardous area classifications should be reviewed to take CO_2 into account. Unlike hydrocarbons, CO_2 and mixtures with brine are not combustible. Depending on the level of impurities in the CO_2 injection stream, the hazardous area classifications may be relaxed. Care should be taken in areas of confined space with potential brine release.

Note: Refer to Clause A3.4.2.1.1 for further safety requirements and considerations with respect to operations within confined spaces.

A3.4.1.9 ***Piping***

All pipe should be designed to accommodate process fluids, pressures, temperatures, and environmental conditions. Pipe in this regard should be considered to include, but not be limited to, process piping, vessels interconnect piping, flow lines, gathering lines, and trunk lines, along with the associated valves, flanges or couplings, regulators, and other equipment used in the piping system.

Piping in corrosive fluid service should be:

(a) Constructed of corrosion-resistant material, e.g., stainless steel, fiberglass, or plastic;

(b) Lined with plastic, fiberglass, or another material to isolate the carbon steel from corrosive process fluids; or

(c) Chemically protected by corrosion inhibitors.

Piping in non-corrosive fluid service may be made of unlined carbon steel.

Note: *For further information see API Spec 5L, API Spec 5LD, API Spec 6D, and ISO 14313.*

A3.4.1.10 Well Planning, Construction and Operation – Wellbore Materials

A3.4.1.10.1 Wellhead and Production Tree Assembly

Wellhead and Production (aka "Christmas") tree equipment should be designed to accommodate the composition of the injected fluid, expected pressure and temperature ranges, and ambient conditions. The wetted areas of the wellhead, tubing hangar, and tree assemblies should be designed to resist corrosion due to injected CO_2 and other injection fluid components. When corrosive fluids are used, this equipment should be made of corrosion-resistant material or clad with CRA material. Chemical corrosion inhibitors may be used, but if they are, should be used in sufficient quantity to prevent corrosion, and the tree should be regularly inspected to ensure that the treatment is effective. Elastomeric seals should be made of material that is compatible with the corrosive fluid service (refer to Clause A3.4.1.5.3).

A3.4.1.10.2 Casing

Casing should be designed as specified in Clause A3.4.2.3.4. Material selection should consider the well-construction period as well as the producing/injection life. Conductor, surface, and intermediate casings should be designed to resist formation fluids (such casings are typically made of carbon steel). Production or long-string casing above the packer may be made of carbon steel if a chemically inert packer fluid is used. It is possible that the casing at the injection zone and below the packer will need to be made of a CRA material such as chrome or stainless steel to resist corrosive brine during the injection life of the well.

Liners that could be exposed to injection fluids should be designed to the same material specifications as the production string described in this clause.

Note: *For further information see API RP 7G.*

A3.4.1.10.3 Tubing

Tubing should be designed to accommodate the injection fluid conditions of the well, sized for the expected rates, and able to withstand the expected injection pressures.

Material selection should be governed by the injection fluids expected in the well. Tubing in corrosive fluid service shall be:

(a) Constructed of a corrosion-resistant material, e.g., chrome alloy (chrome 13), stainless steel, fiberglass, or plastic;

Note: *Use of CRA tubular necessitates special handling techniques and tools.*

(b) Lined with plastic, fiberglass, phenolic resins, cement, or another material to isolate the carbon steel from corrosive brine process fluids. To prevent damage to the lining, care should be used with lined tubing when running wireline or slickline; or

(c) Chemically protected by corrosion inhibitors.

Tubing in non-corrosive fluid service may be made of carbon steel.

Note: *For further information see API RP 7G.*

A3.4.1.10.4 Down-hole packers and tools

Down-hole packers and tools should be designed to accommodate the expected fluids, pressures, and temperatures. For corrosive fluid service, packers should be fabricated of stainless steel or a chrome alloy that is resistant to corrosive fluids. Packer elements should be designed in accordance with Clause A3.4.1.5.2. Down-hole tools such as nipples, mandrels, and mule shoes should be designed in accordance with the material criteria used for the tubing and packers.

Note: *For further information see API Spec 11D1 and ISO 14310.*

A3.4.2 Design

A3.4.2.1 Safety

A3.4.2.1.1 General

If site enclosures are necessary, a safe entry procedure should be established for entering wellhead enclosures and this procedure should be followed by all persons entering the enclosures.

A3.4.2.1.2 Identification signs

Permanent signs specifying the name of the well or storage facility, the name of the project operator, and a telephone number for emergency purposes should be clearly visible. Such signage should comply with local regulations.

A3.4.2.1.3 Warning signs

In areas that can contain accumulations of hazardous/ noxious fluids or vapors, the appropriate warning symbol should be displayed on identification signs. Windsocks should be employed to indicate wind direction (i.e., for assistance in emergency evacuations). Such signage should comply with local regulations.

A3.4.2.1.4 Fire prevention and control

A3.4.2.1.4.1 Permanent equipment spacing

Sources of ignition, flame-type equipment, and fires should not be located within close proximity to a well or unprotected source of ignitable vapors. Equipment should be spaced in accordance with or based on local regulatory requirements, as applicable.

A3.4.2.1.4.2 Combustible material control

Wellsites should be kept free of vegetation and combustible materials.

A3.4.2.1.4.3 Wellhead enclosures

Where enclosures are used for wellhead equipment, the enclosures and wellhead equipment should be designed and constructed to:

(a) Exclude flame-type equipment;

(b) Prevent the accumulation of hazardous/noxious fluids or vapors within the enclosure; and

(c) Use only electrical equipment approved for use within specified hazardous areas, as defined by local regulations governing the location of the storage site.

A3.4.2.2 Wellsite

A3.4.2.2.1 Location

A3.4.2.2.1.1 Setback considerations and proximity to population centers

A thorough evaluation of all surface and subsurface activities and their potential impact on the integrity of the storage complex should be conducted. This, evaluation, which should include but not be limited to an assessment of topographical and physical conditions, including proximity to other subsurface activities and to population centers, should be carried out in accordance with Clause A3.2.9.

A3.4.2.2.1.2 Geological evaluation

A geological evaluation of the storage facility should be conducted in accordance with Clause A3.2.13.4.2 and should include numerical simulations for predicting CO_2 plume size and migration.

Note*: See Clause A3.2.9 for site screening criteria.*

A3.4.2.2.2 Layout, siting, and spacing

The distance between two adjacent wellheads and between wellheads and other surface facilities should ensure the unobstructed access to any well by drilling and service rigs and service vehicles that might be needed during the drilling or service life of the well. Where adjacent wells are closer to each other than a distance equal to the height of a drilling or service rig, the project operator should ensure that physical protection is provided for the adjacent wellhead not being used by a rig or vehicle (e.g., dropped object protection, bump guards, and a cage).

Care shall be taken in the siting of all wells to:

(a) Provide adequate access to the wells for inspection, maintenance, repair, renovation, treatment, and testing; and

(b) Avoid seasonal flooding.

A3.4.2.2.3 Security

A3.4.2.2.3.1 General

Project operators shall restrict unauthorized access to wells and storage facilities and should consider employing security measures appropriate to the site location, e.g.:

(a) Barricades;

(b) 2 m (6.56 feet) high small-mesh industrial-type steel fences;

(c) Locking gates;

(d) Site security personnel, as necessary;

(e) Security lighting; and

(f) Alarm systems.

A3.4.2.2.3.2 Enclosures

Where fences or enclosures are used at wells, they should be constructed in a manner that allows unobstructed egress from anywhere within the confined area.

A3.4.2.2.3.3 Identification signs

Signage should clearly specify restricted access requirements, including warnings against trespassing to those without authorized access. Signage should also comply with all local regulations.

A3.4.2.3 Well Planning and Construction - Drilling

A3.4.2.3.1 General

The depth of the injection zone, bottom-hole temperature, required diameter of the wellbore, lost circulation zones, type of drilling fluid used, over- or under-pressured zones, swelling or sloughing shale, etc. should all be considered in the design of a drilling plan. The potential for fluid invasion and formation damage should also be considered when drilling through the targeted injection zones. The above factors shall determine the type of drill rig and equipment needed to successfully complete the project.

Note: *For further information on drilling practices to help ensure well control and sustained integrity and zonal isolation, see API RP 65 Part 2, API RP 96, API RP 59, API RP 53, and API RP 100-1.*

A3.4.2.3.2 Wellsite considerations for drilling

A3.4.2.3.2.1 General

The location and design of injection wells, i.e., vertical and horizontal deviated wells vs. dual purpose injection and highly instrumented, reservoir surveillance wells should be considered prior to the start of drilling activities. The wellsite should be large enough to accommodate the necessary drilling rig and equipment. A detailed drilling plan should be developed and, in some cases, subjected to an independent peer review (private auditing/consulting companies) to ensure that project goals are met before submitting to regulators. Necessary provincial/territorial/state and local permits should be obtained prior to building the wellsite for drilling.

A3.4.2.3.2.2 Injection wells

Injection wells will be necessary for delivery of CO_2 to the subsurface geological storage facility. Information specific to the location and associated design of CO_2 injection wells should take into consideration the following:

(a) *Selection of a location with suitable well spacing design where the necessary volume of CO_2 can be injected without excessive subsurface pressure interference;*

(b) *Adequate permeability and porosity for the anticipated volume of CO_2 and mixtures thereof required to be injected (so that injection pressures do not exceed the fracture gradient and fail the receiving formations); and*

(c) *Positioning to take into account potential migratory paths from the targeted zone to other geological formations adjacent to the proposed injection formation.*

Note*: See Clause A3.2.9 for well siting requirements.*

A3.4.2.3.2.3 Vertical and horizontal/deviated Injection wells

In some formations, the volumes and injection rates of brine required for injection operations can be more efficiently delivered by horizontal rather than vertical wells. Items that should be considered in drilling horizontal wells are:

(a) *Detailed geology, including the vertical depth of the target injection zone;*

(b) *Azimuth of the horizontal well;*

(c) *Length of the horizontal lateral;*

(d) Degree of build in bend; and

(e) When to start the bend in formation.

(f) Large enough hole and pipe diameters

A3.4.2.3.2.4 <u>Reservoir Surveillance / Observation Wells</u>

Construction of monitoring and observation wells should incorporate materials compatible with all fluids and conditions to be encountered during the life of the project. The location and design of observation wells should take into consideration the following:

(a) Locations that are suitable for monitoring reservoir pressure;

(b) Potential migratory paths from the targeted zone to another formation;

(c) The lateral and vertical heterogeneity of the storage complex;

(d) Fluid interface monitoring at the location of the spill point;

(e) Permeability zones and stratigraphic traps above the storage zones; and

(f) Low-permeability zones or formations adjacent to and in communication with the storage zone.

(g) Large enough hole and pipe diameters

A3.4.2.3.3 <u>Surface casing setting depth</u>

A3.4.2.3.3.1 <u>General</u>

Well surface casing should be set and cemented at sufficient depths to ensure:

(a) Isolation of protected groundwater sources; and

(b) Control of the well under maximum formation pressures and operating pressures prior to the next casing interval.

A3.4.2.3.3.2 <u>Safeguards for the preservation of protected groundwater</u>

All site activities shall be performed in a manner that avoids endangering protected groundwater sources.

A3.4.2.3.3.3 Pressure control for surface casing design

Surface pipe should be set to a depth sufficient to ensure control of the well under maximum formation pressures and operating pressures prior to the next casing interval.

A3.4.2.3.4 Casing design

A3.4.2.3.4.1 General

Casing the well begins with the large-diameter conductor pipe driven or augured into the ground through the surface rubble or loam to hard pan, usually to a depth of 8 to 30 m (26 to 98 ft). The conductor pipe prevents caving and washout at the rig base and provides containment of the cement for the surface casing at ground level. Once in place, the conductor casing is grouted with cement to maintain integrity around the casing and prevent washouts.

The well is drilled out through the conductor to below protected groundwater sources and surface casing is run and cemented back to the surface to protect any groundwater sources encountered. The long-string or injection casing is then drilled out to total depth in the well and cased with the appropriate grade, weight, and size of casing to handle the operating parameters expected in the well and should be cemented back to the surface. If this cannot be achieved, the director of the Regulatory Authority can in some cases issue a waiver. At a minimum, the design of the casing should account for the internal yield strength of the pipe, casing collapse pressure, the pipe body yield, the required internal diameter of the pipe, and the corrosion resistance of the metallurgy.

The following design factors shall be considered:

(a) Safeguards for the preservation of protected groundwater;

(b) Well control requirements during drilling;

(c) Wellbore conditions during the running and cementing of the casing;

(d) The range of operating pressures and temperatures for the well;

(e) Composition of the CO_2 stream being injected into the reservoir;

(f) The projected life of the well;

(g) The integrity of the geological formations being penetrated and the fluid content of each formation;

(h) The depth of the well; and

(i) Monitoring well design considerations.

Note: *For further information see API RP 7G.*

A3.4.2.3.4.2 Service conditions for production casing design

The operating service conditions should be considered during the design of production casing strings for injection and observation wellbores. Considerations in the production casing design should include the following:

(a) The H_2S and CO_2 concentration in the CO_2 stream;

(b) The content of the CO_2 stream and/or the potential to add diverting agents;

(c) The composition of inhibited fluid in the annulus between the injection tubing and production casing;

(d) The operating pressure at the injection zone;

(e) The differential pressure across the injection packer; and

(f) The operating range of temperatures anticipated, taking into consideration the lowest temperature expected due to CO_2 stream injection and the reservoir temperature.

The design influences of the CO_2 injection and storage service conditions should influence decisions on the metallurgy of the casing, and on whether specialty alloys are required and at what part of the casing string special alloys are required (e.g., inconel alloy for the casing string over the injection zone and where the injection packer will be landed).

A3.4.2.3.4.3 Yield strength

The following yield strength design requirements should apply:

(a) *surface casing connected into a wellhead and isolated from the production casing by seals should have a yield strength design to support the maximum operating pressure of the subsurface CO_2 storage facility or be otherwise protected by a pressure-relieving device or open vent;*

(b) *casing string other than surface casing should be designed for a yield strength based on loads from the overburden gradient, formation pore pressures, and expected internal well pressures, and be designed in accordance with site geology;*

(c) *production casing design should be based on the greater of the pressure gradient specified for the subsurface casing string and the maximum operating pressure gradient, with no allowance for externally applied pressure;*

(d) *casing yield strength should be calculated in accordance with API Bulletin 5C2; and*

(e) *the casing collapse and burst pressure rating should be sufficient to prevent well failure with expected pressures for well construction and operation. Safety factors specified in local regulations should also be considered.*

A3.4.2.3.4.4 <u>Collapse strength</u>

The following collapse strength design requirements should apply:

(a) *casing set deeper than 450 m (1476 ft) should be designed for collapse resistance based on a pressure gradient of 12 kPa/m (0.5305 psi/ft), with no allowance for internally applied pressure;*

(b) *productions casing design should be based on the greater of a pressure gradient of 12 kPa/m (0.5305 psi/ft) and the maximum operating pressure gradient, with no allowance for internally applied pressure;*

(c) *the casing collapse pressure should be calculated in accordance with API Bulletin 5C2;*

(d) *casing should not be subjected to a collapse pressure exceeding 90% of the minimum collapse resistance for the grade and weight of the casing being used; and*

(e) *collapse pressure reduction caused by axial loading should be considered in the design.*

Note: *For assistance in developing collapse strength, see API RP 5C5/ISO 13679, API Spec 5CT/ISO 11960, and API TR 5C3/ISO 10400.*

A3.4.2.3.4.5 <u>Tensile design</u>

The following tensile design requirements should apply:

(a) the casing minimum tensile strength should be the lesser of the pipe body strength and the joint strength;

(b) casing should not be subject to tensile loading exceeding 90% of the casing minimum yield strength for the grade and weight of the casing being used; and

(c) casing tensile design should be developed in accordance with API Bulletin 5C2.

A3.4.2.3.5 <u>Liners</u>

Liners should be designed in accordance with Clause A3.4.1.3. The minimum overlap distance should be subject to well design considerations for hanger placement in an area that has sufficient support from the cement above. Extended intervals for overlap can be necessary with unstable formations, e.g., a double-cemented annulus across salt zones in liner laps can be necessary to resist salt creep.

A3.4.2.3.6 <u>Number of casings</u>

The cemented casings installed in a CO_2 storage well should include

(a) one casing set across all protected groundwater source zones; and

(b) one casing set across all porous zones located above the storage complex.

A3.4.2.3.7 <u>Abandonment</u>

Clause 6.3.7 fiberglass tubulars shall apply to drilling abandonment procedures.

A3.4.2.4 <u>Well Planning and Construction - Well Completion</u>

A3.4.2.4.1 <u>General</u>

The completion of an injection well begins with a properly designed cement job in accordance with local regulations that places a well-bonded cement sheath around the injection casing from the casing shoe. This ensures that there is a safeguard for the preservation of protected groundwater aquifers by shielding the fresh water zones with casing and cement. The injection casing is perforated with the appropriate number and diameter of holes to establish sufficient communication with the injection zone(s) of the reservoir to introduce the volumes required. Stimulation or injection enhancement treatments can be necessary; however, any injection enhancement treatment should be performed in a manner that ensures the integrity of the caprock seal. Tubing and associated completion equipment of the appropriate diameter and weight is then run with an injection-style packer to handle the fluid stream. Consideration should be given to the metallurgy of the tubing string and the use of internal coatings within the tubing to prevent corrosion and leakage of the injection string. Injection packers can be made of stainless steel or other corrosion-resistant alloys (see Clause A3.4.1.10.3).

A3.4.2.4.2 Injection rates

The maximum CO_2 injection rate required in the well should determine the size (aka. diameter) of tubing, production casing size, borehole diameter, and other completion equipment needed to handle the volumes injected (and can influence the diameter of the wellhead casing hanger system necessary in the well). The maximum injection pressure should help determine the weight and grade of tubulars for the well. Packers of adequate internal diameter should be considered where subsequent wireline work might be desired during the life of the injection well. Well log data analysis helps to determine most of the well completion criteria, along with the number of perforations in each well, well locations, and the need for sand control systems to appropriately distribute the injected CO_2 along the injection zone interval.

A3.4.2.4.3 Monitoring

The CO_2 injection stream and the annulus between the tubing string and the casing should be continually monitored at the wellhead for pressure. At a minimum, monitoring of the temperature at the wellhead should also be considered.

Injection pressures should be monitored, for the following reasons:

(a) Injection pressure can be a leading indicator for subsurface issues, e.g., if injection pressure builds quickly after a period of no build-up, it is possible that there is a mechanical issue down hole that needs further investigation;

(b) Injection pressure falling quickly can indicate a leaking or ruptured flow line. The project operator should install a pressure safety low (PSL) switch that will activate a shutdown valve to prevent further leakage;

(c) If the injection pressure builds quickly to the point that an overpressure situation could occur, the project operator might want to consider installing a pressure

safety high (PSH) switch that will isolate or shut down the pressure source and thus possibly prevent overpressure.

Injection temperature should be monitored, as this datum is also useful for understanding the density of the injected fluids, which in turn allows bottom-hole injection pressures to be estimated. Pressure monitoring of the annulus is necessary to detect leaks within the tubing string, packer elements, or casing string.

A metering device is necessary to monitor the volume of the CO_2 fluid stream to be injected. Metering devices vary significantly in their operational requirements and can be as simple as an orifice meter or as sophisticated as a coriolis metering device. Onsite monitoring can be performed daily by an operator gathering information from a chart recorder or a remote terminal unit (RTU), or the data can be gathered by a supervisory control and data acquisition system (SCADA) and transmitted via radio, cell phone, or satellite system to a central computer database.

A3.4.2.4.4 Service conditions

Excessive impurities within the CO_2 flow stream can influence the outcome of a project on account of corrosion, improper measurement factors, pump incompatibilities, reservoir volumetric estimates, and can be severe enough to cause reservoir damage (pore-throat plugging, scale, etc.). Monitoring for impurities should be completed using industry standard techniques for sampling the CO_2 flow stream.

Impurities found in produced brine flow streams can cause corrosion problems. This can be removed with the proper EOR system on surface. Hydrogen sulfide (H_2S) is a potential impurity and will react with brine under certain conditions to form corrosive sulphuric acid. Corrosion problems can also occur when carbon dioxide (CO_2) is an impurity in brine injection streams and can form corrosive carbonic acid in the brine. Carbonic acid can also be removed with an EOR treatment system on surface so that it won't be excessive when re-injected under normal operating conditions. Other forms of corrosion, e.g., electrolysis, can exist and are corrected by cathodic protection or other means.

A3.4.2.5 Recompletion of existing wells

A3.4.2.5.1 General

Recompletion designs for converting oil and gas production wells for use as CO_2 injection wells should ensure that the requirements of this SOP are met. Converting production wells for use in CO_2 injection and storage/disposal projects should only be undertaken after careful evaluation. A detailed well conversion plan should be developed and, in some cases, subjected to an independent peer review (private auditing/consulting companies) to ensure that project goals are met before submitting to regulators to apply for permits. It should be noted that oil and gas production and EOR injection wells were originally designed for oil and gas production applications and not for other applications such as CO_2 injection. Therefore, loads imposed on such well operations (including cyclic thermal stresses and high pressure, hydraulic fracturing/stimulation etc.) have to be considered in casing and cement design and life cycle wellbore integrity of CO_2 injection wells (See Sections 2.1, 3.1 and 4.3).

A3.4.2.5.2 Casing

Recompletion of production wells into injection wells shall be dependent on the construction details of the original well. The casing of the wells to be converted should use casing that meets the requirements of Clause A3.4.2.3.3.1. Allowance should be made for the age and condition of the casing so that no recompletion is performed in wells that cannot safely meet the requirements of Clause A3.4.2.3.3.1.

A3.4.2.5.3 Inspection and testing

Prior to conversion for injection operations, the production casing shall be inspected and tested for integrity over its full length by:

(a) obtaining and evaluating cement integrity logs;

(b) running and evaluating a casing inspection log for casing corrosion or damage;

(c) pressure testing of the casing in accordance with field pressure testing techniques (MIT, etc.); and

(d) consideration of performing inspection methods;

(i) baseline temperature, pulsed neutron, and ultra-sonic logs for future comparisons.

(ii) a search for leaks via relevant logs such as temperature and ultra-sonic noise logs.

A3.4.2.5.4 <u>Recompletion of existing injection wells</u>

A well should be recompleted if any the following situations are present:

(a) annular hydraulic isolation is not indicated across confining zones above the storage complex; or

(b) lack of minimum primary cement placement across reservoir coning zones; or

(c) other reasons as specified in Clause A3.4.3.5 and in the cited API standards; or

(d) the well has a loss of mechanical integrity (aka. pressure barrier leaking), as evidenced by:

(i) a failed pressure test (MIT, etc.); or

(ii) leaks found by temperature or ultra-sonic noise logs; or

(iii) communications between the inside of the tubing and the tubing/casing annulus, indicating a leak in the tubing, casing, or packer.

A3.4.2.5.5 <u>Recompletion to regain mechanical integrity and zonal isolation</u>

A3.4.2.5.5.1 <u>General</u>

A well that has compromised mechanical integrity should be worked over or recompleted to re-establish mechanical integrity and zonal isolation. The loss of mechanical integrity should be investigated to determine whether the loss of integrity is from the tubing or packer or if the loss of mechanical integrity is from casing failure. Pressure testing of the tubing and annulus will suggest where the problem lies. Losses of mechanical integrity and zonal isolation should be evaluated by relevant methods as described in API RP 90-1 and API RP 90-2. All recompletion work should have well control and wellbore security as the highest priority.

A3.4.2.5.5.2 <u>Repairing a tubing or packer leak</u>

If the tubing or packer is suspected to have developed a leak, a plan should be developed to identify and confirm the leak's characteristics (location, type, etc.). If the well was constructed in such a way as to have a landing nipple above the packer, the tubing can be isolated and pressure tested. If no blanking plug was used, a mechanical caliper log can be run to locate the leak. If a leak is discovered, the tubing should be removed from the well and inspected and tested. If a seal-bore-type packer or tubing on/off tool was used, the tubing can be removed without removing the packer. Otherwise, the packer should be removed with the tubing.

If the tubing passes a pressure test, the packer or seal assembly should be removed from the well and repaired or replaced. After such repairs or replacements have been completed and the components have been reinstalled into the well, the casing or tubing annulus should be pressure tested to reestablish mechanical integrity. While the tubing is out of the well, a cement evaluation and casing inspection log should be run. All repair plans should be reviewed and approved by the proper Regulatory Authority. If, after a thorough investigation, it is determined that the well cannot be repaired, it should be plugged and abandoned in accordance with Clause A3.4.3.8.

A3.4.2.5.5.3 Repairing a casing leak

If the failed mechanical integrity test was due to a casing leak, a workover or recompletion plan should be developed and executed to repair the damaged area. First, the type of leak should be identified by running a casing inspection log. Cement integrity should be investigated at this time by running a cement evaluation log. Other logs may be run to determine whether there is fluid movement outside the casing. After the results of these logs are evaluated, a repair should be designed.

If flow is detected outside the casing, cement integrity should be reestablished by squeeze cementing with cement or chemical sealants. If the problem is casing failure due to corrosion or a mechanical defect, several options exist to repair the casing leak. Squeeze cementing can be used to repair some leaks. Specially designed cement systems, e.g., ultra-fine cement, very-low-fluid-loss slurries, and solids-free chemical sealant systems have proved effective in repairing casing leaks. Chemical sealants can penetrate pinhole leaks in casing to seal voids behind the casing and pore throats inside the permeability of formations. The use of a casing patch or lining the casing can be necessary to repair large leaks where there is also extensive structural damage in the casing or liner pipe.

In the event of casing collapse the severity of the restriction must be determined. If smaller casing can still be run through the restriction, repair options may allow the insertion of smaller casing and cementing it in place. In severe cases, the collapsed casing may require removal by milling the section and replacement with a scab liner cemented through the milled section. In each case, the internal diameter of the well, and injection capacity will be permanently reduced. A final option is to plug and abandon the well.

Well integrity outside the casing should be established prior to using these methods. If there is fluid movement outside the casing, cement integrity should be reestablished prior to the installation of a liner or casing patch. Wells involved in CO_2 injection and storage operations should be cemented back to surface such that casing replacement of long pipe sections might not be an economical option. In these cases, the available options can be limited to those that involve repairing the casing without pipe replacement, e.g., installing expandable liners and cement or chemical sealant squeezes. However, if casing replacement can be used, care should be taken to ensure that the mechanical integrity of the well can be restored and maintained.

After the required casing repairs have been made the casing should be re-tested with pressure tests and/or leak detecting logs. The packer and tubing will then be rerun into the well and mechanical integrity will be re-established by pressure testing the tubing casing annulus.

A3.4.2.5.6 <u>Well Planning - Abandonment</u>

Clause A3.4.3.8 shall apply to abandonment procedures.

A3.4.2.5.7 <u>Conversion records</u>

Testing, evaluation, recompletion, and abandonment records for wells shall be prepared and retained in the project operator’s files.

A3.4.3 Well Planning - Construction

A3.4.3.1 General

Well construction planning and operations shall meet project goals and objectives while complying with applicable regulations such as those for CO_2, brine and other fluid containment. Published well construction standards cited by regulatory authorities and contractual documents shall also be implemented.

A3.4.3.2 Safety plan

Safety preparedness (response plans) should be in place at a corporate level to mitigate spills caused by unexpected circumstances, e.g., drilling into high-pressure formations, which can cause kicks and the release of formations fluids to weak zones or to the surface.

Note: *For further information see API RP 97.*

A3.4.3.3 Well site

Well sites should be prepared to accommodate all drilling and service company equipment. Preparation will include the drilling rig, mud system, pipe racks, tool sheds, offices, logging trucks, cement pump units, and materials delivery and storage areas. Well sites should also have enough room to allow placement of well-control equipment that is identified in any applicable emergency response plan.

A3.4.3.4 Drilling

A3.4.3.4.1 Inspection, transportation, storage, and handling of casings

Casings should be inspected in accordance with API RP 5A5 and should be transported, stored, and handled in accordance with API RP 5C1.

A3.4.3.4.2 Casing threads

Before intermediate and production casing strings are run, all casing threads should be:

(a) inspected for gauge in accordance with API RP 5B1;

(b) covered by thread protector until the casing joint is hanging vertically in the derrick; and

(c) properly lubricated with a manufacturer-recommended lubricant or as specified in API RP 5A3/ISO 13678.

A3.4.3.4.3 Running casing

Note: For further information see API RP 5A3/ISO 13678, API RP 5A5, API RP 5B1, API RP 5C1, and API RP 7G.

A3.4.3.4.3.1 Casing torque

The following requirements apply to torque:

(a) for proprietary connections, the amount of torque applied to casing connections should be within the specifications set by the casing manufacturer;

(b) applied casing torque should be measured using a torque gauge; and

(c) when practicable, intermediate and production casings should be run using power tongs.

(d) the rig should demonstrate that the torque gauges are often calibrated to be accurate.

A3.4.3.4.3.2 Premium connections make-up

Threads that require a position make-up rather than a recommended torque should be made up in accordance with the manufacturer's recommendations. Torque/turn monitoring equipment should be used during installation. All measurements should be verified to confirm their accuracy by calibrating the measuring devices, including gauges for torque, pressure, weight, etc.

A3.4.3.4.3.3 Threaded joints

Threaded joints should be made up:

(a) in accordance with API RP 5A3/ISO 13678; and

(b) with thread compound that is compatible with the brine being injected, except for the bottom two joints (including the casing shoe), which should be made up with thread-locking compound.

A3.4.3.4.4 <u>Casing cementing</u>

A3.4.3.4.4.1 <u>General</u>

Casing cementing design and operations shall provide, from the casing shoe to the planned top of cement (TOC), a competent cement sheath in the annulus between the external casing surface and the drilled hole's formation surfaces that (a) structurally supports the casing; (b) resists all expected well and formation loads; (c) completely seals and isolates formation pore pressures in the cemented annulus; and (d) protects the casing from corrosive fluids in relevant zones. Defective cement sheaths should be remediated as specified in Clause A3.4.3.5. The well design and construction practices specified in API RP 65, Part 2, should be followed to help provide high enough quality in the drilled hole to enable successful cementing operations and cement sheath performance. Portland based cementing slurries may be used in annuli that don't have or will not have a sustained pH below 4.0 in the formations surrounding the cement. Special non-Portland cements are needed to fill annuli that have or will have a sustained pH environment below 4.0.

A3.4.3.4.4.2 <u>Cementing operations</u>

Casing cementing operations should comply with local regulations and take into consideration applicable specifications and recommended practice Standards, including the following:

(a) API Spec10A/ISO10426-1;

(b) API RP10B-2/ISO10426-2;

(c) API RP10B-4/ISO10426-4;

(d) API RP10B-5/ISO10426-5;

(e) API Spec10D/ISO10427-1;

(f) API RP10D-2/ISO10427-2;

(g) API RP10F/ISO10427-3; and

(h) API Standard 65, Part 2.

A3.4.3.5 Post-job cementing evaluation and remediation

A3.4.3.5.1 General

After the cement has been placed in the annulus, the cement sheath should be evaluated using the methods described in API Standard 65 Part 2, API RP 96, and applicable regulations. During the waiting on cement (WOC) time, the hole should be kept full to maintain an overbalance across potential influx zones. No other rig operations on the well should be performed that will disturb the cement and damage the seal or cause the cement to set improperly. Regulations may require casing to be pressure tested. Preferably, pressure testing casing should be done before significant gel strength has developed. However, such pressure testing will be limited by the pressure ratings of plugs, floats, cementing heads and other equipment. Pressure testing can be done after the cement has set but this can result in micro-annulus formation or damage to the cement sheath. The pressure should be held on the casing for the shortest length of time required to accomplish the test. The effect of pressure testing will depend on the properties of the cement, the pressure at which at the casing is tested and the properties of the formation around the cement. Mechanical stress modeling can assist in determining the best time to conduct the pressure tests. In the absence of regulatory guidelines on compressive strength requirements before drilling out, usually a minimum compressive strength of 500 psi (3.45 MPa) is recommended before drilling out the shoe of the cemented casing (API Standard 65-2).

After the required WOC time has elapsed, the cement evaluation practices specified in API Standard 65 Part 2 should be followed to determine whether the cement has been properly placed in the annulus and the top of cement (TOC) depth is acceptable. Other methods may be performed to determine whether the annular cement's placement and sealing performance are suitable and has no leaks or defects, e.g., wireline logs that evaluate cement placement (API 10TR1) and logs that can detect flow behind the casing by measuring temperature, noise, and the flow of oxygen-activated water and CO_2 molecules.

Note: *More information is available in the IADC Drilling Series Book titled "Well Cementing Operations" published by the International Association of Drilling Contractors in May 2015.*

Defective cement sheaths should be repaired using selected remedial methods and materials that meet the structural support and sealing requirements of the primary cementing design. For example, when the TOC is too deep and a potential flow zone is exposed, a cement squeeze should be used to repair the defect and seal the annulus from the measured TOC to the planned TOC. However, when structural support is not an issue and only flow path sealing is needed, non-cement types of chemical sealing systems, e.g., solids-free and CO_2-resistant, chemical gel sealants, may be squeezed into flow paths such as a micro-annulus between the casing and the cement sheath to achieve deep penetration sealing in those flow paths in the cemented annulus.

A3.4.3.5.2 Pressure Testing in Mills

Casing that has not been pressure tested in the mill for strength in accordance with API Specification 5CT/ISO 11960 should not be installed in CO_2 injection and storage wells/disposal wells.

A3.4.3.5.3 Field Pressure Testing

Production casing should be pressure tested for leaks and strength by:

(a) isolating the casing from the formation; and

(b) testing to a pressure that is 1.1 times the maximum operating pressure measured at the wellhead, but not greater than 100% of the casing minimum yield pressure at any point along the casing and continuing the test for the period of time required to reach stabilization.

(C) verify that measurements are accurate by calibrating the measuring devices, including gauges for pressure testing.

After drilling out the casing shoe, leak-off pressure testing (LOT) or formation integrity testing (FIT) shall be performed to confirm that the shoe will contain the drilling pressures expected for the next hole section plus a safety factor (aka. kick tolerance).

A3.4.3.5.4 Well Planning and Construction - Core acquisition

A3.4.3.5.4.1 General

Conventional or sidewall core shall be collected to sufficiently document the expected CO_2 displacement profile and storage complex prior to developing or commissioning the surface facility and injection wells.

Note: *See Clause A3.2.12.2 for further requirements on geological and hydrogeological characterization of the storage unit.*

A3.4.3.5.4.2 Core handling

Every core taken shall be:

(a) extracted from the core barrel in a manner that preserves its condition;

(b) placed in a core container strong enough to prevent breakage of the core;

(c) accurately and durably labeled with the,

(i) name of the well;

(ii) depth interval from which the core was obtained; and

(iii) sequential number of the container; and

(d) where caprock core is taken, preserved in a manner that minimizes evaporation and preserves the fluid saturations of the core before shipment to the laboratory.

A3.4.3.5.4.3 Core analysis during subsequent operations

Additional core collection and/or analysis of existing cores or additional sidewall core from caprocks and target reservoirs should be undertaken, as needed, for site development and operations to ensure proper construction and operation of injection and monitoring wells. The results of the analysis, if different from previous site characterization analysis, should be considered in injection and well design and operations.

A3.4.3.6 Well Planning and Construction - Completions

A3.4.3.6.1 General

All wells involved in CO_2 injection and storage projects, whether injectors or monitoring wells, shall be completed in a manner that meets project goals while maintaining wellbore integrity. A detailed completion plan should be developed and, in some cases, subjected to an independent peer review (private auditing/consulting companies) to ensure that project goals are met before submitting to regulators. All materials used should meet the requirements of Clause A3.4.11.

A3.4.3.6.2 Workover procedures

Workover procedures used during the completion process shall employ best industry practices while maintaining a focus on safety and wellbore security.

A3.4.3.6.3 Wireline and logging procedures

Wireline logging procedures should be used to determine casing and cement integrity, correlate formation depths, and establish baseline conditions for monitoring and verification activities. The logs used may include, but should not be limited to, (a) casing inspection log; (b) cement evaluation log; (c) cement bond log; (d) density, dipole (shear) sonic log, FMI, and ultrasonic imaging logs; (e) temperature log; (f) ultra-sonic noise log; and (g) pulsed neutron, gamma ray, spontaneous potential, and collar locator log.

The wireline and logging procedures used during the completion process should employ best industry practices while maintaining a focus on safety and wellbore security. Various wireline, slick-line, and tubing conveyed logging jobs can be necessary throughout the operating life of a CO_2 injection well, including wireline logs to determine casing integrity, checking cement sealing performance, correlation of formation depths, and the establishment of baseline conditions for monitoring and verification activities.

A3.4.3.6.4 Well Planning and Construction - Wellbore integrity

Wellbore integrity should be established using logs and pressure testing. The casing should be pressure tested prior to starting completion. Once the injection or monitoring packer is installed, the tubing and casing annulus should be pressure tested to ensure mechanical integrity. All pressure tests should be performed to applicable standards and in a manner that does not cause casing and cement debonding, cement stress cracking, and/or a micro-annulus.

A3.4.3.6.5 Well Planning and Construction - Formation testing

Formation tests may be performed to establish reservoir properties, e.g., injectivity testing, pump testing, initial reservoir pressure testing, and pressure transient testing, separately or in combination. These tests shall be reviewed to ensure that the formation has the required injectivity and to confirm reservoir models that will be used to predict CO_2 movement in the reservoir. Accurate records should be kept of all completion activities and retained throughout the life of the project. If required, copies of all completion records should be transferred to the authority that has jurisdiction for issuing well permits and to any other authority that has jurisdiction for any other relevant regulations.

A3.4.3.7 Well Planning - Workover procedures

A3.4.3.7.1 General

During the life of the project it is possible that a workover will be required to repair a defective component or to obtain information concerning wellbore integrity. After CO_2 injection into the receiving reservoirs has occurred, all workovers should be conducted using best industry practices for maintaining wellsite safety and wellbore security. Well control should be of primary concern to ensure that no injected CO_2 can escape from the formation to the surface. A detailed workover plan should be established prior to starting any workover operation and subjected to stakeholder and peer review. Necessary permits and approvals from all Regulatory Authorities involved should be obtained prior to starting workover operations (e.g., sundry notices).

A3.4.3.7.2 Wireline logging procedures

Wireline and tubing conveyed logging may be used during a workover for monitoring or in recompletion activities. All wireline operations during workovers should be performed in accordance with best industry practices for pressure control. The composition of wellbore fluids should be used by owners, operators, and service providers to prevent damage to wireline cable and tools.

A3.4.3.7.3 <u>Wellbore integrity</u>

During workover activities, wellbore integrity should be reestablished as in the original completion. Wellbore integrity can be verified using a combination of wireline logging and pressure-testing methods.

A3.4.3.7.4 <u>Workover records</u>

Accurate and detailed records should be kept of all workover operation activities. An accurate record should be kept of any changes made to, or recompletion of, any well (either monitor or injector) involved in the project. These records need to be retained for the life of the project. If required, copies of all workover records should be transferred to the Regulatory Authority issuing the well permit and to any other Authority as is required.

A3.4.3.8 <u>Well Planning - Abandonment and restoration</u>

A3.4.3.8.1 <u>General</u>

Well abandonment design should ensure the protection and isolation of potential CO_2 storage formations, prevent the migration of CO_2 or protected groundwater from one horizon to another, and ensure that the surface is returned to near-original condition. This activity is be guided by the Regulatory Authority issuing the well permit. In the U.S. Class II CO_2 EOR wells (with continued incidental storage) are regulated by the state agency while Class VI wells could be regulated either by the state agency or federal agency having regulatory jurisdiction. In Canada, the AER regulates CO_2 injection wells (See Section7.0) Clauses A3.4.3.8.2 to A3.4.3.8.5 specify requirements pertaining to abandonment of wells during the various project activities.

Note: *For further information see API Bulletin E3.*

A3.4.3.8.2 <u>Discovery of an abandoned well</u>

All abandoned wells should be identified, and applicable records searched to determine how the well was plugged and whether the method of plugging met the requirements of Clause A3.4.3.8. If the well cannot be identified, no records on how the well was plugged can be found, or the well was plugged in a manner that did not meet the requirements of Clause A3.4.3.8, the well should be monitored for leakage and repaired if necessary.

A3.4.3.8.3 Abandonment of a well during construction

If, during the construction of a well, a condition occurs that requires the well to be abandoned, it should be plugged at the direction of the authority that has jurisdiction and that issued the well permit, and in a manner that ensures that all the requirements of Clause A3.4.3.8 are met. Such conditions might include, but are not limited to, loss of drilling tools in the well, a stuck pipe that cannot be recovered, loss of coring or logging tools in the well, or conditions in the hole that make continuation of well construction operations unacceptable. The loss of a radioactive logging tool requires special provisions beyond those specified in Clause A3.4.3.8. All wells plugged as a result of a lost radioactive tool should be plugged in such a manner that Clause A3.4.3.8 is met as well as special provisions required to plug a well where a radioactive tool is lost. The preferred method of plugging should be the balanced plug method. Care shall be taken to ensure the integrity of each plug, before the next plug is installed.

Note: *For further information, see API Bulletin E3.*

A3.4.3.8.4 Well is unsuitable after completion but before brine injection has occurred

If, after completion, a well is found to be unsuitable for injection or monitoring, it should be plugged to meet the requirements of Clause A3.4.3.8. Casing/cement integrity and zonal isolation shall be established, and if remedial work is required, the well shall be remediated so that casing/cement integrity and zonal isolation are established. All open perforations should be sealed off using the cement squeezing technique as well as by permanent bridge plugs and cement plugs above the perforations. The well should then be further plugged at the direction of the Regulatory Authority that issued the permit and in accordance with a method that meets the requirements of Clause A3.4.3.8.

A3.4.3.8.5 <u>End of the project</u>

At the end of the life of the project, all wells associated with the project shall be plugged in a manner that meets the requirements of Clause A3.4.3.8. During plugging, care shall be taken to maintain well control at all times so that no injected fluids are released into the wellbore or the surface. All CO_2 shall be flushed from the wellbore and the wellbore should be filled with a fluid of a density and chemical composition that will maintain well control and integrity. Casing/cement integrity and zonal isolation logs should be rerun and compared to the original baseline logs to confirm cement/wellbore integrity and zonal isolation. If either the cement or the casing is found to be deficient, repairs should be made so that the wells can be successfully plugged to meet the requirements of Clause A3.4.3.8. All open perforations should be sealed using the squeeze cementing technique and then plugged by a series of cement plugs, permanent bridge plugs, or both, or by completely filling the well with cement. The Regulatory Authority issuing the well permit should be consulted with respect to plugging requirements.

A3.4.4 Well Planning, Construction, and Operation - Corrosion control

A3.4.4.1 <u>General</u>

Mechanical integrity and zonal isolation are high priority concerns during the operation of CO_2 injection and storage sites. A primary means of mitigating mechanical integrity problems is effective design of materials, coatings, and chemical programs to prevent internal and external corrosion of steel components. Once designed and in place, ongoing operations should include a program to monitor the effectiveness of the corrosion mitigation efforts. The program can include, but is not limited to, the following:

(a) chemical analysis of injected fluids for indications of trace metals;

(b) corrosion coupons placed in the CO_2 injection stream; and

(c) ultra-sonic or other non-destructive testing of vessels and pipe for wall thickness (metal) loss.

(d) mechanical integrity testing and leak detection logging

Ongoing maintenance should include external coatings and periodic visual inspection of the interior portion of all vessels for corrosion.

A3.4.4.2 __Design considerations__

Design should include a careful analysis of the CO_2 injection fluid composition throughout the injection period. Brines exposed to CO_2 are typically corrosive and may contain impurities such as H_2S that need to be considered. The design should also consider external environmental conditions. External corrosion can be influenced by the weather, ability of pipe to maintain external coatings, and whether the steel is exposed to the air (e.g., buried pipe versus pipe in a pipe rack). In offshore locations, exposed materials such as piping and structural steel are specified to accommodate salt laden air. Onshore locations may or may not have this environmental consideration for exposed materials depending on surface conditions (weather, dust, etc.).

A3.4.4.3 __Cathodic protection systems__

Piping and vessels should be adequately protected against galvanic corrosion by using cathodic protection. Vessels and skids should be adequately grounded. An impressed-current cathodic protection system should be considered for flow lines, pipelines, gathering lines, trunk lines, and (possibly) well casing in areas subject to highly corrosive conditions.

A3.4.5 Operation and Maintenance

A3.4.5.1 __General__

An operations and maintenance plan should be developed and implemented. The plan should provide for regular inspections to prevent a device or well component related to surface equipment from failing and to ensure that degradation normally experienced during the operation of equipment is repaired.

A3.4.5.2 ***Operation constraints and limitations***

The geological, structural, and integrity characteristics of the proposed storage region should be evaluated to establish constraints and limitations, e.g., minimum and maximum operating conditions and pressures.

This evaluation should include:

(a) *reviewing available pressure and production history data and test information from existing wells located in the proposed storage zone and in surrounding formations that might be in communication with the storage zone;*

(b) *conducting the necessary tests to evaluate acceptable and safe operating conditions, e.g., the pressure and temperature of the storage operations;*

(c) *ensuring that the maximum operation pressure shall not exceed 90% of the fracture pressure of the injection zone;*

(d) *determining the injection rate, pressure buildup, and formation flow characteristics;*

(e) *evaluating the reservoir capacity. A material balance analysis should be conducted to determine the reservoir capacity and to evaluate the storage zone's ongoing containment ability and the nature of any external drive mechanism; and*

(f) *establishing a range of operating pressures and temperatures for the wells.*

A3.4.5.3 ***Operating and maintenance procedure audits***

Audits of well operations and maintenance procedures should be performed yearly or as needed to ensure that processes and procedures adapt to any changes in operational or environmental conditions. It is possible that procedure audits will need to be revised as equipment ages.

A3.4.5.4 ***Design and operations records***

All design and operations records should be kept up-to-date for the duration of the project.

A3.4.5.5 ***Measurement of injected CO_2***

The CO_2 stream should be continuously metered at the custody transfer or receipt point to the storage facility and to individual injection wells as follows:

(a) each meter should be calibrated at regularly scheduled intervals and not less often than annually;

(b) the composition of the CO_2 stream should be determined at regularly scheduled intervals and not less than annually;

(c) given the potential variability in the properties and impurities of the CO_2 stream, flow- and density-meter runs shall measure salinity, TDS (total dissolved solids), pressure, and temperature to allow for accurate metering;

(d) calibration records should be maintained for accounting audit purposes; and

(e) injection volumes should be recorded for production accounting and regulatory purposes and to allow monitoring and verification.

A3.4.5.6 <u>Recording management of change</u>

Surface equipment should be maintained in accordance with accepted industry practice and local regulations. The mechanical integrity of piping and vessels should be maintained by the use of proper external and internal coatings, as necessary. As specified in Clause A3.4.1.5.1, if chemical methods are used for corrosion prevention, routine inspection and maintenance of chemical performance should be performed as a safeguard against excessive corrosion.

Routine maintenance of valves, chokes, rotating equipment, and safety systems should be performed to ensure proper operation. Records of routine and preventive maintenance as well as repairs should be maintained by the project operator.

Note*: See API RP 97 for further information on management of change.*

A3.5 WELL PLANNING AND OPERATION - MONITORING AND VERIFICATION

A3.5.1 Purpose

The purpose of monitoring and verification (M&V) is to address health, safety, and environmental risks and assess storage performance. Monitoring, verification, and accounting activities support a risk management strategy that enables an assessment of CO_2 injection and storage performance. "Monitoring" refers to measurement and surveillance activities necessary to provide an assurance of the integrity of CO_2 injection and storage process. "Verification" refers to a comparison of the CO_2 injection and storage project's predicted and measured safe performance relative to key performance indicators (KPIs).

A3.5.2 M&V Program Phases

A3.5.2.1 <u>General</u>

M&V programs should be flexible and adapt to changes in storage or injection conditions as well as to the different phases of the project. They should also help avoid poor performance and incidents caused by abnormal CO_2 flows within the storage complex. There are four generally accepted M&V phases, i.e., pre-injection, injection, post-injection, and post-closure. Each of these phases has different M&V requirements that relate to different periods in the project's life cycle and, as such, can require adaptation throughout the life of the project.

A3.5.2.2 <u>Pre-injection phase</u>

During the pre-injection phase (which occurs before sustained injection starts and corresponds to the site selection, characterization, design, and development periods), project vulnerabilities shall be identified, solutions to mitigate recognized vulnerabilities shall be proposed, monitoring tasks shall be defined, and baseline monitoring data shall be acquired.

A3.5.2.3 <u>Injection phase</u>

During the injection phase (which corresponds to the commencement of the operational period and can also include pilot injection tests), monitoring activities should be implemented to manage CO_2 containment risks and storage and injection performance. Monitoring practices should be evaluated and adapted during the entire course of injection to ensure that monitoring activities continue to be appropriate and effective.

A3.5.2.4 <u>Post-injection phase</u>

During the post-injection phase (which includes the closure period in the project's life cycle), monitoring activities should provide sufficient information for managing containment risk and for demonstrating the long-term integrity of the CO_2 storage complex.

A3.5.2.5 <u>Post-closure monitoring phase</u>

During the post-closure monitoring phase (which relates to the post-closure period in the project's life cycle), limited monitoring is maintained to verify that the storage complex is performing as predicted, and eventually to demonstrate that the containment risk has been reduced to a level where the need for further monitoring is eliminated. The post-closure monitoring phase is not addressed in Clause A3.5.

A3.5.3 M&V Program Objectives

Project operators shall develop and implement an M&V program suited to their operation. The M&V program should be defined according to the project phases specified in Clause A3.5.2 and shall be designed to serve the following objectives:

(a) to protect health, safety, and the environment by detecting early warning signs of significant irregularities or unexpected movement of injected CO_2 or formation fluid

(i) through gathering information on the effectiveness of long-term containment of CO_2 throughout the project's life cycle; and

(ii) by providing sufficient evidence, in the judgment of independent qualified experts, that the CO_2 has not moved beyond the confining zone, including no leakage to a shallow subsurface zone or to the surface;

(b) to support risk management throughout the project's life cycle;

(c) to provide adequate information for

(i) decision support within the project (among the project operators and principal project partners) and for communication with regulatory authorities; and

(ii) communication with other stakeholders external to the project, including the local community or local landowners as appropriate;

(d) to test the predictions of dynamic reservoir flow modeling and other models against observations and data documented from monitoring, enable adjustment of models to improve long-term storage performance predictions, determine the frequency and duration of monitoring activities, and support demonstration that criteria required for site closure are attained;

(e) to continuously improve the M&V program by adapting it to changing project circumstances and advances in technology or best practices;

(f) *to support quantification calculations for injected and stored CO_2 in accordance with verification requirements identified for accounting and injection flow performance purposes;*

(g) *to support management of CO_2 injection operations in a safe and environmentally responsible manner that complies with applicable regulations by gathering information that demonstrates that storage site operations are within the performance limits accepted by the project operator and the regulatory authorities;*

(h) *to support maintenance or improvement of storage system efficiency, safety, and economic performance;*

(i) *to support long-term stewardship of the storage site (injection, post-injection, and post-closure phases); and*

(j) *to support the achievement of project objectives and the preservation of project values additional to those specified in Items (a) to (i).*

A3.5.4 Well Planning and Construction - M&V program design

A3.5.4.1 <u>M&V program procedures and practices</u>

The M&V program shall document:

(a) *the alignment of the M&V program with the project's risk management policy, and should include accountabilities and responsibilities for monitoring activities that support the risk management plan;*

(b) *reviews of monitoring tools and monitoring activity performance, as appropriate, to inform the need to make changes to the monitoring program;*

(c) *communication of M&V requirements to internal and external stakeholders as appropriate;*

(d) *the allocation of appropriate resources to provide an assurance that monitoring activities are carried out in a diligent and timely manner;*

(e) *the explicit purpose and performance metrics for all monitoring activities; and*

(f) *the procedures for properly documenting the monitoring activities and the processes implemented for evaluating monitoring performance against the original purpose and pre-defined operational metrics.*

A3.5.4.2 <u>M&V program required specifications</u>

The M&V program should be based on the planned CO_2 injection operation and include the following:

(a) *the projected CO_2 volumetric capacity of the target formation(s) within the storage complex;*

(b) *the CO_2 injectivity of the target within the storage complex;*

(c) *the planned rate of injection of CO_2;*

(d) *the total mass of CO_2 to be stored;*

(e) *the boundaries of the CO_2 storage complex, including stratigraphic definition of the injection target and primary seals;*

(f) *the locations of planned or existing wells that penetrate the CO_2 storage complex within the predicted area of influence;*

(g) *the manner in which the M&V program will fulfill requirements imposed by applicable regulations;*

(h) *the schedule and reporting procedures to document compliance with M&V requirements in applicable regulations or as imposed by or agreed with regulatory authorities;*

(i) *the sensor systems and human observations that provide objective data on system behavior collected at a frequency sufficient to support efficient operation under normal conditions and to help prevent or recognize HSE impact under upset conditions;*

(j) *the process and frequency for reviewing the M&V program, which will include assessing observed performance against predicted performance, responding to changes in assumptions, and incorporating project lessons learned and changes to best practices. The process should consider:*

  (i) *the frequency of updates to the program when observed performance corresponds to predicted performance;*

  (ii) *the frequency of updates to the program when observed performance does not correspond to predicted performance;*

(k) *the process and schedule for documenting M&V changes and updates;*

(l) *the risk-based ranking of scenarios that have the potential to cause significant HSE impact or to negatively affect storage performance, including the planned rate of injection, the total mass of injection, or the integrity of containment. This description should encompass the link between M&V design and any updated risk assessment results in compliance with the risk assessment criteria specified in Clause A3.3;*

(m) *all baseline measurements that have been obtained. Such normal fluctuations in baseline need to be determined to differentiate natural variations from leakage, as follows:*

(i) *at a minimum, baseline measurements should be taken for every sampling position that will later be used for monitoring;*

(ii) *consideration should be given to having baseline measurements that extend geographically beyond the core plume and anticipated area of elevated pressure;*

(n) *the monitoring targets (or thresholds) for*

(i) *each ranked risk identified within the risk management framework;*

(ii) *identifying when there is a need for modifications to the numerical prediction models and monitoring protocols;*

(iii) *supporting demonstration that criteria required for site closure are attained (see Clause A3.6.4);*

(iv) *managing CO_2 injection operations, including the composition of the CO_2 stream, the injection rate, injection volumes, and reservoir pressures;*

(o) *the design of the monitoring program at the surface, in the biosphere, between the biosphere and the CO_2 storage complex, and in the storage complex, specifying the assumptions and expected conditions for which the monitoring program is designed, the parameter changes that the program is designed to observe, and the timing (frequency) and duration of monitoring activities for each monitoring target for each monitoring phase;*

Note: *Examples of monitoring technologies include the following:*

(1) *at the surface: near-surface geophysical monitoring, tiltmeter monitoring, eddy covariance***,** *Interferometric Synthetic Aperture Radar (InSAR), laser spectroscopy, gravity monitoring, electromagnetic surveys, hyperspectral imaging, soil gas surveys for displaced reservoir gases.*

(2) *in the biosphere: resistivity surveys, instrumented monitoring wells including sampling drinking water wells for pH and water chemistry monitoring, soil gas flux monitoring*

(3) *between the biosphere and the CO_2 storage complex: repeat 3D seismic or vertical seismic profiling (VSP) surveys, micro-deformation via downhole tiltmeter arrays, instrumented observation wells for pressure and temperature monitoring, repeat well logging, and*

(4) *in the CO_2 storage complex: repeat 3D seismic or VSP surveys, micro-deformation via downhole tiltmeter arrays, passive seismic monitoring, instrumented observation wells for pressure and temperature monitoring, downhole resistivity measurements, repeat well logging, tracer surveys.*

(p) *the requirements for data acquisition from monitoring activities needed for integration into the project's predictive modeling program and the frequency with which this integration will occur. This description shall also identify how* *monitoring and modeling jointly support the project's risk management program. Predictive models shall be used with a description of the potential range of outcomes and should incorporate any associated degrees of uncertainty. The M&V program shall include a process for gathering and using information that could improve CO_2 injection operational performance and storage safety;*

(q) *the decision criteria based on monitoring performance indicators used to determine whether the storage complex is exhibiting behavior outside the expected range of performance. The system of measurements and observations that comprise the monitoring performance indicator should have sufficient accuracy and precision that changes in monitoring observations can be distinguished with reasonable certainty relative to the decision criteria. This requires that detection thresholds (in a single observed parameter) or conditions (in a set of parameters) within each monitoring performance indicators must be determined and identified;*

(r) *the schedule and process for verifying both storage integrity and quantification of stored volumes of CO_2;*

(s) *the performance measures (i.e., criteria for evaluating the success of the monitoring program) to be met by all phases of the monitoring program, with statements of justification and a level of detail appropriate for the objectives to be achieved.*

A3.5.4.3 M&V program recommended specifications

The M&V program should take into consideration and describe the following:

(a) *the applicable performance measures and purposes of monitoring during the different phases of the project's life cycle, the monitoring technologies that will be used during each phase, the rationale for their selection, and any additional measurements or other data needed to support decisions involving monitoring activities. Technologies to monitor the following should be included:*

(i) injected CO_2 volume;

(ii) CO_2 flow rate and injection pressure;

(iii) composition of injected CO_2;

(iv) spatial distribution of the CO_2 plume;

(v) spatial distribution of elevated pressure

(vi) pressure within the storage complex;

(vii) well integrity;

(viii) leakage outside of the CO_2 storage complex;

(ix) integrity of the confining zone;

(x) extent of displacement of formation water in the formation;

(xi) pressure changes in the deepest aquifer overlying the confining zone;

(xii) potential induced seismicity or microseismic activity;

(xiii) geochemical changes in the reservoir that relate to risks from CO_2 injection or that enable validation of other observations such as those related to changes in permeability; and

(xiv) contamination of other potentially competitive resources that have been identified within an accepted area of review;

(b) *the methodology used to select and qualify monitoring technologies. The following elements should be included:*

(i) defining monitoring tasks;

(ii) identifying potential monitoring technologies;

(iii) evaluating the effectiveness of technologies against the required tasks;

(iv) estimating the life cycle risk reduction benefits of available technologies;

(v) comparing the life cycle costs of available technologies (if desired);

(vi) a description of the placement of observation wells, if part of the monitoring system, and all monitoring activities associated with each such well including a description of the methods involved in all continuous and periodic measurements to be performed;

(vii) the methods and frequency used to monitor changes in groundwater quality and composition from baseline conditions in the lowermost underground source of drinking water;

(viii) the identification and description of pre-existing wells in the area of interest that do not meet the requirements specified in Clause A3.5.3 (g). A determination should be made for each pre-existing well in the area of influence. If ongoing monitoring is required a description of the monitoring methods to be used should be included.

A3.5.4.4 <u>M&V program contingency monitoring</u>

The M&V program should describe the following:

(a) pre-defined monitoring observations that would likely indicate conditions other than normal expected system performance. These observations will arise from: (i)

measurements taken from individual instruments or methods; (ii) qualitative observations; and (iii) combinations or sets of measurements and observations.

(b) *pre-defined observations for all baseline parameters measured*

(c) *the operational changes more likely to be required, based on the occurrence of specific conditions other than normal operational parameters and the appropriate risk-based preparations to effect those changes;*

(d) *in the event of observations or conditions that are outside the anticipated range of parameters, the project operator's first response plan to check, confirm, and retake the observations, to the extent possible;*

(e) *the project operator's second response plan to follow up on the data checks specified in Item (d) in a broader sense to establish situational awareness based on all available information. The assessment of this information should be based on expert judgment, including experts from outside the project; and*

(f) *the project operator's third response plan to develop a remediation strategy including, if necessary, reevaluation of risks, monitoring programs, and operations, based on the information gathered through implementing the second response plan.*

Notwithstanding the project operator's diligent efforts to pre-define observations that are standard versus non-standard, the project operator should remain vigilant for the emergence of observations and conditions that do not fall clearly into pre-specified categories. Procedures should be documented to address situations arising from non-standard project conditions such as may require the establishment of a consultation panel of independent qualified experts.

A3.6 WELL & PROJECT PLANNING - CESSATION OF INJECTION

A3.6.1 General

The purpose of Clause A3.6 is to provide guidance to and establish predictability for project operators and regulatory authorities regarding the expectations of the post-injection closure period. Clause A3.6 establishes three fundamental objectives that should be accomplished during the period which starts at the cessation of injection and specifies the systematic process that can be followed to demonstrate and document compliance with these objectives.

The three objectives are as follows:

(a) sufficient understanding of the storage site's characteristics;

(b) low residual risk; and

(c) adequate, uninterrupted well integrity.

Note*: These objectives are not intended to replace requirements related to transfers of liability and responsibility under applicable regulations.*

A3.6.2 Activities

Immediately upon the project operator's termination of CO_2 injection, the first of the possible two closure periods begins. Known as the post-injection closure period, it is the period in which the project operator begins to prepare the storage site for post-injection activities. The activities included in this period are as follows:

(a) Risk management

(i) implementation of all required elements of the risk management plan; and

(ii) planning and review of risk treatment.

(b) Development — Operations and maintenance

(i) abandonment and closure of injection and monitoring wells not intended for post-injection use; and

(ii) operation and maintenance of remaining monitoring or remediation wells.

(c) Monitoring and verification

(i) implementation of the long-term requirements for the post-injection period; and

(ii) ensuring that brine plume characteristics are as expected.

It is envisioned that at the end of brine injection, the project operator will use the post-injection closure period to prepare the site for the transfer of responsibility and liability, with the intention of transferring all rights, obligations, and liabilities associated with the site to a designated authority. When this occurs, the site is said to achieve "closure". It is only at the point of transfer of responsibility and liability that a site achieves "regulatory or permitted" closure status. It is possible for a project operator to not transfer liability or responsibility for a site to a designated authority or responsible entity. In this case, the site will not achieve the milestone of site closure and will not enter the post-closure period but will remain in the post-injection closure period.

A3.6.3 Post-Injection Closure Period Plan

The project operator should develop a post-injection and closure period plan for the storage site. The plan shall outline the process for meeting applicable criteria to enable the site to enter the post-injection and closure period. The main parts of the plan should be as follows:

(a) *specification of provisional criteria for post-injection and closure operations, including*

(i) the requirements specified in the storage permit;

(ii) site-specific performance targets for site closure, as agreed to with the regulatory authority; and

(iii) the conditions for site closure specified in applicable regulations;

(b) *specification of the provisional site closure qualification process and timing;*

(c) provisional plans for site decommissioning, including plans for plugging and abandonment of wells and decommissioning of surface facilities associated with CO_2 injection and monitoring operations; and

(d) provisional plans for post-injection and closure period monitoring and remedial activities required by regulatory authorities.

The post-injection closure period plan should be updated as appropriate during the project's life cycle, as specified in Clause A3.3. The post-injection and closure period plan should be initiated when the project operator has ceased injection of CO_2 and therefore has entered the post-injection and closure period.

A3.6.4 Post-Injection and Closure Period Qualification Process

A3.6.4.1 <u>General</u>

The post-injection and closure period qualification process should follow a structured and transparent approach, ideally a joint effort between the project operator and regulatory authority or independent verifier (if a verifier is engaged). The process should be designed to identify compliance with individual risk and uncertainty risk management, specifically that risks and uncertainties have been gradually minimized and managed throughout the CO_2 storage project's life cycle. The objectives should be as follows:

(a) *to understand the total CO_2 storage system sufficiently to detail how its future evolution can be assessed with a high degree of confidence. In the case of EOR, consider future operation and re-starting CO_2 injection to recovery more hydrocarbons that migrated into the reservoir from other deeper reservoirs. Well Planning and Construction – well infrastructure development and Well Planning and Operation shall govern the methods by which data are collected and used to understand the total system. One recognized component for ensuring sufficient understanding of the total system is to understand the pressure aspects of the system. Specific component considerations should include the following:*

(i) *an understanding of current and future CO_2 plume dispersion and migration.*

Note*: Whereas stabilization of the plume (i.e., cessation of significant movement) is ideal, it may not occur in some storage sites and thus not specified as a requirement in this SOP;*

(ii) *an understanding of reservoir pressure evolution based on time series measurements;*

(iii) *an understanding of the pressure decay over time, specifically as compared to elevated reservoir pressure (taking into consideration the fact that a change in pressure is not an appropriate metric to specifically denote non-compliance);*

(iv) *an understanding of the implications for longer-term pressure evolution models; and*

(v) *an understanding of the displacement of formation water;*

(b) *that risks and uncertainties have been reduced to a level where future negative impacts on human health, the environment, or economic resources are unlikely. This shall be accomplished by using the processes and plans specified in Clause A3.3 – Well Planning which will be used to evaluate the spread in performance predictions since cessation of injection, obtained using a set of model realizations (feasible dynamic models), show a converging trend and that the uncertainty band on the predictions of CO_2 plume migration and pressure development is within acceptable limits; and*

(c) *to ensure well integrity by following the processes specified in Well Planning – risk assessment and Well Planning and Construction – well infrastructure development to the remaining monitoring wells, abandonment and plugging of injection or unused monitoring wells, which will form the basis for ensuring the required integrity.*

A3.6.4.2 Site closure qualification process

The site closure qualification process should comprise the following actions:

(a) a dialogue between the project operator and regulatory authority expressing the intent of ceasing injection, initiating execution of the site closure plan, and finalizing site closure performance targets;

(b) compilation of requirements for site closure, including:

(i) the requirements specified in the brine storage permit, updated as appropriate throughout the life of storage project;

(ii) site-specific performance targets for site closure, updated as appropriate throughout the life of the CO_2 storage project and agreed upon by the designated regulatory authority; and

(iii) conditions for site closure, in accordance with applicable regulations (including wells selected for abandonment);

(c) preparing a plan to demonstrate compliance with the requirements for site closure, including plans for collecting, reviewing, assessing, and structuring the information necessary for obtaining permission to initiate execution of the plans for site decommissioning;

(d) compilation of reports, results, and other data that will form the basis for the site closure assessment, including

(i) operational logs that document the history of CO_2 storage site operations;

(ii) monitoring logs that document and map the history of monitoring and verification activities;

(iii) an updated project risk database showing how significant individual risks that have been analyzed and managed have evolved throughout the life of the project, including a description of the reasons for upgrading or downgrading risks during the life of the project;

(iv) a description of how key uncertainties have been analyzed and managed throughout the life of the project and a retrospective review of key decisions made under risk uncertainties;

(v) compilation of project performance targets, including a record of changes made during the life of the project and a description of the reasons for those changes;

(vi) compilation of results and conclusions drawn from monitoring, modeling, and risk assessments to support a demonstration of compliance with site closure requirements, including a description of how geological, geochemical, and geomechanical characterization and flow simulation models have been calibrated or adjusted; and

(vii) a description of historical storage performance relative to predictions from modeling and simulations;

(e) updating of storage performance predictions and identifying potential residual health, safety, and environmental risks, including potential risks to future containment stemming from well abandonment and site decommissioning;

(f) updating of the environmental impact assessment, including potential impacts from site decommissioning;

(g) verification of storage performance predictions and environmental impact assessments; and

(h) assessment of compliance with site closure conditions

A3.6.5 Well Planning - Decommissioning

A3.6.5.1 Preparation

As the site moves into the post-injection and closure period, aspects of the project beyond injection shall be considered. The two major components, i.e., wells and surface facilities, should be prepared for appropriate post-injection and closure actions as follows:

(a) preparation of plans for ongoing site monitoring as required by applicable regulations and with the objectives of identifying migration of CO_2 out of the storage unit, any leakage of stored CO_2 at the surface, and impacts from migration of formation fluids. This should include:

(i) identification of monitoring technologies appropriate for the site; and

(ii) a timeline for site surveys;

(b) identification of appropriate corrective actions to address the most likely events identified from modeling of the storage unit required during the closure qualification process, which should include fluid migration (CO_2 and/or formation water or hydrocarbons) via wells;

(c) preparation of plans to notify future landowners and (if applicable) resource owners of the storage site and remaining subsurface infrastructure; and

(d) identification of the entity responsible for undertaking the long-term stewardship plans, including contact information for the public.

A3.6.5.2 Wells

As part of the post-injection closure plan, the project operator should have a provisional plan for decommissioning injection and monitoring wells to ensure that the wells do not allow fluid movement between zones and will continue to protect usable-quality water aquifers. The plugging and abandonment of wells should conform to this plan, be performed in accordance with the requirements of the regulatory authority and Well Planning – risk assessment and Well Planning and Construction – well infrastructure development, and take the following into consideration:

(a) *isolation of all existing storage zones from the immediate wellbore area;*

(b) *isolation of all zones of usable-quality groundwater;*

(c) *prevention of migration of* CO_2*, hydrocarbons, or water from one horizon to another;*

(d) *provision of a sufficient cement seal and prevention of fluid movement through any channels adjacent to the wellbore;*

(e) *maintenance of the integrity of the cement (cement may contain additives such as fly ash, etc.);*

(f) *isolation of all formations bearing oil, gas, geothermal resources, and other valuable minerals from zones of usable-quality groundwater;*

(g) *prevention of escape of oil, gas, or other fluids to the surface or to zones of usable-quality water;*

(h) *separation of porous and permeable formations from other porous and permeable formations;*

(i) *separation of lost circulation intervals in the well from other porous and permeable formations;*

(j) *isolation of the surface casing (or intermediate casing) from open holes below the casing shoe;*

(k) *sealing of operator-installed wells at the surface;*

(l) *primary sealing of historical wells; and*

(m) *long-term isolation of injected brine or displaced formation fluids (including brine and hydrocarbons) from all usable groundwater, economic deposits, and soils, and from the surface.*

A3.6.5.3 <u>Surface facilities</u>

All surface facilities and equipment associated with the storage project that is not intended for post-closure monitoring or contingencies should be removed. All facilities that are deemed to be part of the permitted storage site and owned by the landowner or required by regulatory mandate should remain and be maintained in a manner consistent with best practices and all applicable legal and regulatory requirements.

A3.6.6 Long-Term (post-closure) Stewardship

Long-term stewardship, more commonly known than the term in this SOP called the "post-closure period" Local regulations may specify requirements for long-term stewardship when the field's oil and gas mineral lease has expired, and all subsurface mineral rights and pore spaces are returned to the rightful owner. By definition, post-closure periods are not in the scope of this SOP. Therefore, the post-closure period is acknowledged as a part of a process which is marked by the transfer of responsibility and liability but is not considered by this SOP.

APPENDIX 4 - APPLICABLE STANDARDS AND GUIDELINES FOR WELL CONSTRUCTION, WELL OPERATIONS, AND WELL INTEGRITY

This reference list includes standards and other documents which address well construction, well operations and well integrity.

Engineering design, systems and equipment related documents:

API RP 5C7 Coiled Tubing Operations in Oil and Gas Well Services

API RP 49 Drilling and Well Servicing Operations Involving Hydrogen Sulfide

API RP 64 Diverter Systems Equipment and Operations

API RP 65-2 Isolating Potential Flow Zones During Well Construction

API RP 5A3 Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements

API RP 90-2 Annular Casing Pressure Management for Onshore Wells

API RP 92U Underbalanced Drilling Operations

API RP 96 Deepwater Well Design and Construction

API Spec 5CT Casing and Tubing

API Spec 5ST Coiled Tubing U.S. Customary and SI Units

API Spec 5C1 Care and Use of Casing and Tubing

API STD 6ACRA Age Hardened Nickel-Based Alloys for Oil and Gas Drilling and Production Equipment

API STD 7CW Casing Wear Tests

API Spec 7K Drilling and Well Servicing Equipment

API Spec 10B-2 Testing Well Cements

API Spec 16C Choke and Kill Equipment

API Spec 16D Control Systems for Drilling Well Control Equipment and Diverter Equipment

API Spec RCD Rotating Control Devices

API STD 53 BOP Equipment Systems for Drilling Wells

API STD 65 Cementing Shallow Water Flow Zones in Deepwater Wells

API TR 1PER15K-1 Protocol for Verification and Validation of High-Pressure High-Temperature Equipment

API 17TR8 High-Pressure High-Temperature (HPHT) Design Guidelines

EI Model Code of Safe Practice Part 17 Vol. 1: HPHT Well Planning

EI Model Code of Safe Practice Part 17 Vol. 2: Well Control during the Drilling and Testing of High-Pressure Offshore Wells

EI Model Code of Safe Practice part 17 Vol. 3: High-Pressure and High-Temperature Well Completions and Interventions

ISO TR 10400/API TR 5C3 Equations and Calculations for Casing, Tubing and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing (Addendum published 2015)

ISO 10405 Care and Use of Casing and Tubing

ISO 10417/API RP 14B Subsurface Safety Valve Systems

ISO 10418 Analysis, Design, Installation and Testing of Basic Surface Process Safety Systems

ISO 10423/API Spec 6A Wellhead and Christmas Tree Equipment

ISO 10424-2/ANSI/API Spec 7-2 Threading and Gauging of Rotary Shouldered Thread Connections

ISO 10426-1/API Spec 10A Cements and Materials for Well Cementing

ISO 10426-2/API RP 10B Testing of Well Cements/Recommended Practice for Testing Well Cements

ISO 10426-4/API Spec 10B-3 Testing of Deepwater Well Cement Formulations

ISO 10426-4/API Spec 10B-4 Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure

ISO 10426-5/API Spec 10B-5 Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure

ISO 10426-6/API Spec 10B-6 Methods of Determining the Static Gel Strength of Cement Formulations

ISO 10427-3/API RP 10F Performance Testing of Cementing Float Equipment

ISO 10432/API Spec 14A Subsurface Safety Valve Equipment

ISO 11960 Steel Pipes for Use as Casing or Tubing for Wells

ISO 11961/API Spec 5DP Drill Pipe

ISO 13354 Shallow Gas Diverter Equipment

ISO 13533/API Spec 16A Drill Through Equipment (BOPs)

ISO 13628-1/API RP 17A Design and Operation of Subsea Production Systems

ISO 13679/API RP 5C5 Procedures for Testing Casing and Tubing Connections

ISO 13680/API Spec 5CRA Corrosion-Resistant Alloy (CRA) Seamless Tubes for Use as Casing, Tubing and Coupling Stock

ISO 14310/API Spec 11D1 Packers and Bridge Plugs

ISO 14998 Downhole Equipment – Completion Accessories

ISO 15156/NACE MR 0175 Materials for Use in H2S-Containing Environments in Oil and Gas Production

ISO 16070/API Spec 14L Lock Mandrels and Landing Nipples

ISO 17078-4 Practices for Side Pocket Mandrels and Related Equipment

ISO 17824 Sand Screens

ISO 20815 Production Assurance and Reliability Management

ISO 23936-1 Non-Metallic Materials in Contact with Media Related to Oil and Gas Production – Part 1: Thermoplastics

ISO 23936-2 Non-Metallic Materials in Contact with Media Related to Oil and Gas Production – Part 2: Elastomers

ISO 28781 Subsurface Barrier Valves and Related Equipment

NORSOK D-001 Drilling Facilities

NORSOK D-002 System Requirements Well Intervention Equipment

NORSOK D-007 Well Testing System

NORSOK D-010 Well Integrity in Drilling and Well Operations

NORSOK M-710 Qualification of Non-Metallic Sealing Materials and Manufacturers

NORSOK U-001 Subsea Production Systems

Norwegian Oil and Gas 117 Well Integrity Guideline

Norwegian Oil and Gas 135 Classification and Categorization of Well Control Incidents

Well Management Related Documents:

API Bulletin E3 Environmental Guidance Document: Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations

API Bulletin 97 Well Construction and Interface Document

API RP 17N Subsea Production System Reliability and Technical Risk Management

API RP49 Drilling and Well Servicing Operations Involving Hydrogen Sulfide

API RP54 Occupational Safety for Oil and Gas Well Drilling and Servicing Operations

API RP59 Well Control Operations

API RP75 Development of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities

API RP90-1 Annular Casing Management Program for Offshore Wells

API 10TR6 Evaluation and Testing of Mechanical Cement Plugs

APPEA Prevention, Intervention and Response for Offshore Well Incidents

APPEA Self-Audit Checklist for Offshore Operations

APPEA Well Operations Competency Management Systems

ENFORM IRP Volume # 15 Snubbing Operations

IADC HSE Case Guidelines for Land Drilling Units

IADC HSE Case Guidelines for Mobile Offshore Drilling units (MODUs)

IADC Deepwater Well Control Guidelines

IEC 61511 Safety Instrumented Systems for the Process Industry Sector

IOGP 415 Asset Integrity – the key to managing major incident risks

IOGP 435 A guide to selecting appropriate tools to improve HSE culture

IOGP 463 Deepwater wells – Global Industry Response Group recommendations

IOGP 476 Recommendations for enhancements to well control training, examination and certification

IOGP 510 Operating Management System (OMS) Framework

IOGP 511 OMS in practice

ISO 13702 Control and Mitigation of Fires and Explosions on Offshore Production Installations

ISO 14224 Collection and Exchange of Reliability and Maintenance Data for Equipment

ISO 15544 Requirements and Guidelines for Emergency Response

ISO/TS 16530-2 Well Integrity for the Operational Phase

ISO 17776 Guidelines on Tools and Techniques for Hazard Identification and Risk Assessment

ISO/TS 17969 Guidelines on Competency Management for Well Operations Personnel

NORSOK Z-013 Risk and Emergency Preparedness Assessment

Norwegian Oil and Gas 024 Competence Requirements for Drilling and Well Service Personnel

Norwegian Oil and Gas 117 Well Integrity

Norwegian Oil and Gas 135 Classification and Categorization of Well Control Incidents and Well Integrity Incidents

OGUK OP064 Relief Well Planning

OGUK OP065 Competency for Wells Personnel including example

OGUK OP071 Guidelines for the Suspension and Abandonment of Wells including Guidelines on Qualification of Materials for the Suspension and Abandonment of Wells

OGUK OP092 BOP Systems for Offshore Wells

OGUK OP095 Well Life Cycle Integrity Guidelines

OGUK SC033 Well-Operators on Well Examination and Competency of Well-Examiners, Issue 1, November 2011

API Technical Report 5C3 Technical Report on Equations and Calculations for Casing, Tubing and Line Pipe, and Performance Properties

API Spec 5CT Specification for Casing and Tubing

API Spec 5B/ISO 11960 Specification for Threading, Gauging and Thread Inspection of Casing, Tubing, and Line Pipe Threads/Petroleum and Natural Gas Industries – Steel Pipes for Use as Casing or Tubing for Wells (Connections)

API Spec 6A Specification for Wellhead and Christmas Tree Equipment

API Spec 10A/ISO 10426-1Specification for Cements and Materials for Well Cementing

API Standard 53 Blowout Prevention Equipment Systems for Drilling Wells

API RP 65-1 Cementing Shallow Water Flow Zones in Deepwater Wells

API Standard 65-2 Isolating Potential Flow Zones during Well Construction

API RP-90 Annular Casing Pressure Management for Offshore Wells

API RP 90-2 Annular Casing Pressure Management for Onshore Wells (to be issued)

API RP 96 Deepwater Well Design and Construction

API RP 100-1 Hydraulic Fracturing – Well Integrity and Fracture Containment

API RP 100-2 Managing Environmental Aspects with Exploration and Production Operations Including Hydraulic Fracturing

API RP-1170 Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage

API RP-1171 Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs

ISO/TS 16530-1 Well integrity – Part 1: Life cycle governance

ISO/TS 16530-2 Well integrity – Part 2: Well integrity for the operational phase

NORSOK Standard D-10 Well integrity in drilling and well operations

NACE MR0175/ISO 15156 Petroleum, Petrochemical and Natural Gas Industries – Materials for use on H2S containing Environments in Oil and Gas Production

New documents in development:

API 5EX Expandable Tubulars

API 10TR7 Mechanical Behavior of Cement

API 17TR4 Subsea Equipment Pressure Ratings

API 17TR13 General Overview of Subsea Production Systems

API STD 16AR Repair and Remanufacture of Drill-Through Equipment

API STD 18LCM Product Life Cycle Management

API RP 92M Managed Pressure Drilling Operations

API RP 92P Pressurized Mud Cap Operations for Rigs with Subsea BOP Systems

IADC Well Design and Execution Agreement

ISO 16530-1 Well Integrity – Life Cycle Governance

Web-sites:

API: http://www.api.org

APPEA: http://www.appea.com.au

DNV GL: https://www.dnvgl.com/rules-standards

Energy Institute: https://www.energyinst.org

ENFORM: http://www.enform.ca

IADC: http://www.iadc.org

ISO: http://www.iso.org

NORSOK Standards: https://www.standard.no/en

Norwegian Oil and Gas: https://www.norskoljeoggass.no/en

Oil and Gas UK: http://oilandgasuk.co.uk

SPE: http://petrowiki.org/Well_integrity

www.wellintegrity.net

APPENDIX 5 - CEMENTING FUNDAMENTALS, EVALUATION/LOGGING TECHNIQUES AND PRACTICES TO ASSURE A GOOD PRIMARY CEMENT JOB AND ZONAL ISOLATION

A5.1 CEMENT PLACEMENT

Regardless of the cement slurry design, to effect long term isolation and an effective seal in the annulus, the chosen slurry must be placed completely around the casing. This process requires good mud removal and careful attention to displacement mechanics.

A key resource document for well construction is API Standard 65-2, "Isolating Potential Flow Zones during Well Construction." This document is an industry collaboration to identify key steps in the cementing process including initial site selection, design considerations, operational controls and post cementing operations and evaluation. The standard has been adopted into regulations in many areas, and should be considered included by reference with this work.

As noted in the overview of the API Standard:

"This standard contains practices for isolating potential flow zones, an integral element in maintaining well integrity. The focus of this standard is the prevention of flow through or past barriers that are installed during well construction. Barriers that seal wellbore and formation pressures or flows may include mechanical barriers such as seals, cement, or hydrostatic head, or operational barriers such as flow detection practices. Operational barriers are practices that result in activation of a physical barrier. Though physical barriers may dominate, the total system reliability of a particular design is dependent on the existence of both types of barriers."

In the overview; the API designates barriers as mechanical and operational elements. This is reflected in the definition of a barrier or barrier element with the document:

"A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed."

For cement to function as a barrier element, as noted it must be designed properly to address the chemical environment in the well. By using one of the described slurry designs that address CO_2 interaction, and attention to the mechanical properties of the set cement, the first part of the design is complete. The remaining task is to properly place the cement in the annulus to affect a barrier in the annulus.

There are several practices and factors that can affect cementing success. Well-designed cementing operations optimize cement placement through assessing laboratory testing of the cement, maintaining the placement pressures within the pore pressure – fracture gradient window, properly designing fluid systems such as spacers with emphasis on density and rheological properties, and using compatible fluids in the displacement of the mud in the well. While this list is not exhaustive, the intent is to highlight salient points that should be considered within the relationship of drilling and cementing operations.

Hole quality: To obtain a successful cement placement, hole quality should be addressed. Drilling parameters such as directional surveys must be part of the cementing job design. Caliper logs are useful in determining cement volumes as well as flow regimes of the fluids being used.

Directional data is critical to designing proper standoff of the casing through use of centralizers. Knowing where various build sections in the well are located allow for better and more effective placement of centralizers. Directional data including azimuth information is entered into centralizer modeling and displacement simulators to greatly improve simulation quality.

Drilling fluids: The selection of the drilling fluid is an important drilling practice that can impact cementing results. Samples of the drilling fluid should be used in the laboratory to check compatibility of the spacer with the drilling fluid, and to optimize the rheology of the spacer and its ability to effectively remove the drilling fluid. In the cases where non-aqueous fluids are used, laboratory work should also include an evaluation of the surfactants used in the spacer(s) to remove the NAF (non- aqueous fluids) and leave the pipe and formation water wet.

Casing hardware: Defined as the mechanical devices attached to or integral within the casing, casing hardware is selected to provide optimized performance in the well. Casing centralizers, used to move the casing toward the center of the well are important to provide a consistent flow area around the casing during cement placement. If the casing is off centered, a preferential flow path will exist, limiting the placement of cement on the narrow side of the annulus. In cases where the casing is touching the formation, no cement can be placed in that area, thus potentially compromising isolation.

API Specification 10D addresses bow spring centralizers and offers the user standards where the centralizers can be tested to minimum industry standards. Data from these tests can be used in centralizer placement simulators to determine the optimum number and placement of bow spring centralizers in the well.

There are several instances where bow spring centralizers may not have application. These include portions of the well where the side load on the centralizer exceeds its design limits, or in wells where the added drag from the bow spring centralizer would exceed the allowable force to run the casing in the well. In those instances, use of rigid or solid centralizers is appropriate.

API has issued two technical reports, "Selection of Centralizers for Primary Cementing, API 10 TR4 and API Technical Report API 10TR5, "Methods for Testing of Solid and Rigid Centralizers." These two technical reports, coupled with Specification 10D provide the users with selection criteria for centralizers, recommended placement methods, and the equations needed to determine centralizer placement.

Suppliers of API centralizers and cementing service companies have computerized programs that accept survey data, caliper information and casing data to provide selection and placement of the various centralizers to allow for optimized flow around the casing.

Other pieces of casing hardware are the float collar and float shoe. These devices provide one-way check valves to prevent backflow of the cement after placement. If the hydrostatics in the annulus exceeds those of inside the casing, the resulting u-tube would allow flow of the cement back into the casing if the float equipment was not in place. The current API Recommended Practice 10D on Cementing Float Equipment designates several categories for equipment performance. This document is currently being rewritten and will include several additional testing categories and ratings that will address varying flow rates, temperatures and pressures. Information on the document development is available on the API standards site.

Additional pieces of "casing hardware equipment" can include wiper plugs, cementing plug containers and heads, and finally any equipment such as liner hangers that could cause some sort of flow restriction.

Cement wiper plugs are used to provide a mechanical separation of various fluids inside the casing as the fluids are being pumped. The plugs are also used to give a positive indication of the end of displacement. Wiper plugs should be matched to the landing profile of the float equipment, and be able to function at the bottom hole temperature, pressures and be compatible with the drilling fluid type. Not all wiper plugs are compatible with all types of float equipment or other equipment such as stage collars and liner hangers. Wiper plugs and associated equipment should be designed for the specific casing string being cemented.

Cementing plug containers allow for launching of various plugs during the cementing operation. Optimally these systems can function without the need for shutting down the pumping and removing the head to insert a plug or other device. Cementing heads can also provide pressure containment in the event the float equipment does not prevent backflow due to u-tubing of fluids.

Finally, consideration should be given to any equipment that could cause a restriction in flow area. Close tolerance can restrict fluid flow causing excessive pressure drop and potentially limit circulation rates or cause lost circulation. These devices include some liner hangers, liner top packers, external casing packers and other such equipment. Simulations should be run to determine the impact on the equivalent circulating density should this equipment be used in the well. This will allow the design to account for the flow restrictions and modifications can be made to fluid density, rheology or pump rates to address any concerns.

Engineering design: To properly engineer a well design, sound engineering practices must be employed that address the well objectives and meet all the regulatory requirements of the well. The cementing objectives should contain performance requirements for the cement slurry design which should include the need for any gas control, minimum acceptable thickening time, needed strength development, free fluid, slurry stability and fluid loss. Mechanical properties such as Young's Modulus and Poisson's Ratio may also be needed to ensure the system can withstand the stresses encountered throughout the life of the well.

Engineering design of the cementing job should start with determination of where the cement needs to be placed, what zones have the potential for flow, and where isolation in the well is required. Once that is determined, then the remaining well and design parameters can be addressed. These include:

Pore Pressure / Fracture Gradient – impacts slurry density and circulating rates

Temperature – impacts retarder selection, strength development, need for specialty materials

Slurry Volumes – impacts thickening times, placement pressures, final ECD

Engineering software: There are several industry simulators available as tools to aid in the design of a cementing operation. These are key tools for the design engineer to be able to better understand the impact of such variables as:

Surge and swab pressures – impacted by running speed of casing and casing reciprocation

Circulating pressures – impacted by fluid rheology, fluid densities and pump rates

Centralizer placement – impacts casing drag forces, circulating pressures and displacement efficiency

Displacement mechanics and effectiveness – optimized through centralization, casing movement, pump rates, fluid selection

Static pressure calculations – impacts fluid densities and volumes (top of cement)

Specialty cement calculations – critical in foamed cementing operations

As is true with all simulation software, the quality of the input directly impacts the quality of the simulation. Care must be exercised to use the best and most accurate available information for the simulation. While the use of a cementing simulator is highly recommended, their use does not obviate the engineer from applying sound engineering practices. Computer programs are not sufficiently sophisticated to remove the engineer from the equation, and the engineer must be able to determine if the output from the simulator is practical, applicable and makes sense.

Recommendations: To properly design and execute a cementing operation, the objectives of the job must be determined, the design made to address the objectives, and an evaluation plan to assure the operations addressed the objectives of the job, are critical design elements. To aid this process, the guidance found in API Standard 65-2 should be considered as a starting point in the design.

Gathering good quality data for use in an appropriate cement job simulator is important to the design. However, good quality engineering that takes into account equipment capabilities, well limitations and the means used to address those parameters is a key to the success of the operation.

A5.2 CEMENT EVALUATION

Cement evaluation is independent of the type of well to be drilled. Whether the well is for oil and gas production, injection of fluids or CO_2 sequestration, the goal of cement evaluation is to determine the presence of a solid in the annulus that can provide isolation in the annulus. The tools and techniques used for cement evaluation do not change with the purpose of the well, but will vary with the data needed to determine of the quality of the cement in the annulus.

Cement evaluation is usually thought of as running a cement bond log (CBL) and attempting to interpret the results to decide if there is isolation in the wellbore. That interpretation is often made with little or no information on what happened during the drilling and cementing of the well, the cement systems used or the properties of the set cement at the time of logging.

Quality and meaningful cement evaluation is much more than simply running a CBL. Understanding the objectives of the cement job, the design limitations imposed by those objectives and the resulting slurry and job designs are all integral parts of cement evaluation.

To effectively evaluate a cement sheath, location data from the cement job, the slurry designs used and the information that can be obtained from the evaluation technique must be understood. Attempting to perform a cement evaluation in isolation and based solely on the log output from a CBL, or any log, invites considerable error and bias into the interpretation.

This review discusses various methods of cement evaluation, from job data, casing and formation pressure testing through sonic and ultrasonic logging. The limits of each technique are outlined along with cautions on how misinterpretation of the results can lead to determination of cement integrity that may not be appropriate.

An overview of cement evaluation, and a risk based discussion of which technique may be best based on the cementing objectives is included. Reducing risk uncertainty in cement evaluation is discussed along with the "validity" of the various data sets available to the engineer to perform a proper cement evaluation on the well.

Understanding the objectives of the cement job sets the boundary conditions for the designing the cement jobs, and from those designs the ability to evaluate the resulting cement placement and well isolation can be determined. Setting the evaluation methodology and understanding the type of information required to apply that methodology can improve the quality of the evaluation.

A5.3 CEMENT JOB EVALUATION TECHNIQUES

Cement Bond Logs

Cement bond logs (CBL) were introduced in the 1950s. In one of the early papers by Grosmangin, Kokesh and Majani published in 1960, the authors conclude:

“This new tool can be used to evaluate the quality of the cement job around a casing string and, in many cases that its use may eliminate the necessity of expensive inflow and circulation tests.”

Paraphrasing the remainder of the conclusion, the authors note that with additional research on cementation and the propagation of sound, the interpretation of the cement bond log can be made even more reliable.

Through the next several decades, improvements in the basic CBL have occurred, along with the development of more sophisticated tools and interpretation techniques. What remains consistent throughout those decades is the dependence on the indirect measurement of the cement-to-casing interface to interpret the effectiveness of a cementing treatment.

A statement by Fertl, Pilkington and Scott in their 1974 paper addresses some of the limitations:

“Despite its potential, the cement bond log is probably one of the most abused, misused, and misunderstood logs used in the oil field today. Mis-calibration, inadequate information, and a severe lack of standardization are enough to push petroleum engineers into a morass of bewilderment.”

The authors realized depending only on a cement bond log would not lead to effective cement evaluation. Without information on the cement systems pumped, how the job was performed and the criteria used to determine the success of the operation, proper cement evaluation is tenuous at best.

The goal of cement evaluation depends on the objective of the job. If the objective is to have pressure isolation at a casing shoe for continued drilling, the evaluation technique may simply be a pressure test. For objectives requiring top of cement above a certain point in the well, then pressure matches using job data, temperature surveys or sonic logs may be all that is required.

Determining the presence of zonal isolation is one of the more difficult tasks in cement evaluation. Depending on the length of the interval requiring isolation and the slurries pumped, the selection of evaluation technique can become quite complex, and will require the use of multiple sets of data and are fundamental to CO_2 storage applications.

Understanding the Objectives and Limits of Cementing

Understanding the objectives of the job, and the design parameters used to meet those objectives, a decision should then be made as to how the effectiveness of the cement job is to be evaluated. Coupled with this is a determination of the success criteria to be used to evaluate if the job has been performed properly and the objectives met.

As noted in the discussion of cementing, for effective cement job design, the slurry, placement and ultimate objectives of the operation must be understood. Once this is performed, the actual slurry design is developed, and its composition can impact the selection of evaluation technique and may dictate a particular type of electronic log be used for the evaluation.

For example, laboratory data from the ultrasonic cement analyzer (UCA) may be used to "calibrate" an ultrasonic log. The data is used to set the baseline for the expected value of the impedance of the cement in the annulus. The acoustic impedance is a function of slurry density and ultrasonic travel time, with the travel time being determined by the UCA.

Pressure Testing

One of the simplest and most common methods of cement evaluation is a pressure test. This can be a test at the end of a cement job to "check the floats," a casing pressure test before drilling out the casing, casing shoe tests or liner top tests. Understanding the meaning and limits of each of these tests is important in the evaluation of cementing.

Checking the floats at the end of a cement job may give an indication that the valves in the float equipment have closed and are holding. However, this is only true where the differential pressure at the end of a job is high enough to provide a u-tube pressure capable of moving the top plug back up the casing. The top plug is a pressure fit inside the casing, and requires pressure to push it back up the casing. For example, to push a

7 inch (17.78 cm) top cement plug back up a casing string requires approximately 150 psi (1.03 MPa). A differential pressure at the end of the job less than 150 psi (1.03 MPa) would not move the plug, and therefore any float check would not show flow at surface because the plug, and not the float equipment would prevent flow. On many cement jobs, the differential pressure at the end of the job is too low to move the top plug up the casing, and the "float check" test at the end of these cement jobs does not evaluate the float valves and is invalid.

Because of this, it is critical to calculate the differential or u-tube pressure at the end of the cement job. If it is low, the test to "check the floats" at the end of the job is meaningless. Instances where this can occur are with extended or high angle casing strings, jobs with limited vertical lift of cement, and jobs where the density difference between the cement and the mud are limited.

Positive pressure tests on the casing evaluate the ability of the top cement plug seated on the float equipment to seal. There can be a successful casing pressure test with no set cement below the plug. This is readily evidenced by the fact that many operations routinely pressure test the casing immediately after bumping the plug.

Formation pressure testing after drilling out the casing shoe is often required by regulation before drilling ahead to the next objective. The leak-off test is used to determine the presence of a pressure seal at the casing shoe. In some wells, the calculation of leak-off pressure at the bottom of the well can be impacted by mud compressibility which should be taken into account for accurate determination of the leak off pressures.

Testing of liner tops and overlaps should be performed with an understanding of leak paths. A successful positive or negative pressure test can indicate the overall system is holding pressure, while an unsuccessful test will indicate only the presence of a leak and will not give an indication of the source of the leak. The leak path can be at the top of the liner, through the shoe of the liner, in the upper casing or through some surface leak in the system. As noted, these tests when successful indicate the total system is pressure tight, but a failure of the test will require additional evaluation to determine the leak path.

Pressure testing evaluates overall systems rather than individual components. A successful test may occur when only one component of a multi-component system is functioning. Failure of a test can be an indication the total system is not working.

Finally, pressure-matching job data can give an indication of the success of the cement job and allow calculation of the approximate top of cement in the annulus. While not a definitive test, the lift pressure may be used to approximate that the top of cement is above some minimum point in the well. This test can be very useful in cases of loss of circulation during the job.

Temperature Logs

Temperature logs are used to determine top of cement, and the presence of flow behind casing. With respect to finding the top of cement, the log is used to locate changes from the normal temperature gradient brought on by the exotherm of cement setting. The log must be run within the time window when the cement is setting to catch the exotherm. The lighter weight the cement, and the narrower the annulus, the less exotherm there will be, and the reliability of the measurement reduces.

Because heat rises in the annulus, determining the precise top of cement using a temperature log is not practical. Depending on the cement system and size of the annulus, the uncertainty in the top of cement can exceed 100 feet (30.48 m). To improve the reliability of a temperature log, multiple runs can be made and a comparison of the temperatures made. This will give a differential temperature at each point in the well and aid in better determining the presence of the cement.

Determining flow in the annulus with a temperature log requires sufficient flow rate to “move” the temperature up the hole. Temperature logs, coupled with noise logs, can not only identify flow, but with sufficient evaluation may give an indication if the material moving in the annulus is fluid or gas. Supplementing the temperature log with the noise log in those instances gives more data and can result in better remedial actions for any needed repair.

Sonic and Ultrasonic logs

Temperature and noise logs may be considered “passive” measurements where the log only records a specific parameter in the well. Sonic and ultrasonic logs are considered “active” logs because the tools emit some sort of sound and then “listen” to the response of the well to that sound. Sonic logs utilize sound in the frequency of approximately 20 kHz where ultrasonic logs can use a frequency anywhere from 80 to 700 kHz, depending on the tool with 80 to 200 kHz being more common.

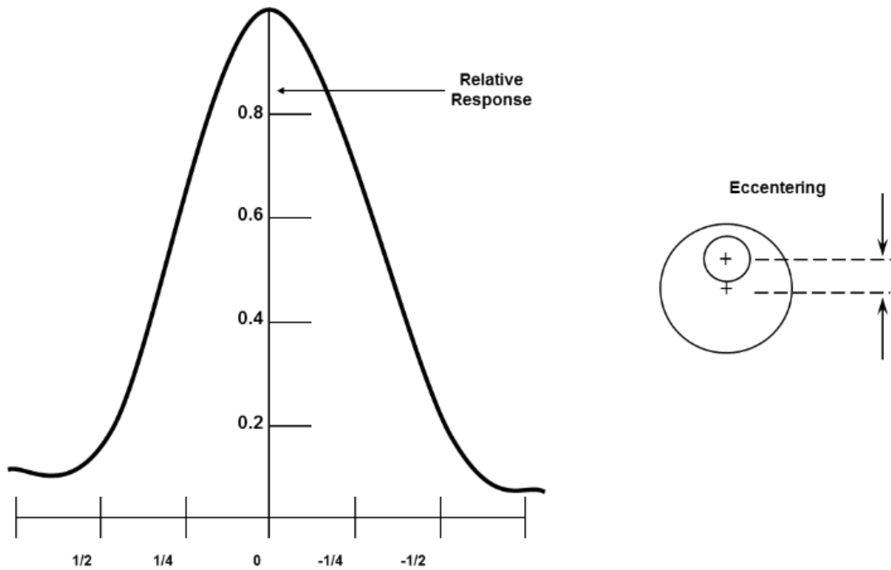
Conventional Cement Bond Log (CBL)

As noted, the conventional sonic cement bond log (CBL) was first introduced in the 1950s with an early paper presenting the technology presented in 1960 by Grosmangin, Kokesh and Majani. Still in common use, the basic tools use a transmitter and a pair of receivers spaced at 3 and 5 feet (0.91 m and 1.52 m). The transmitter sends out an omnidirectional signal which is picked up by the receivers. The receiver at 3 feet (0.91 m) presents the amplitude of the signal and at the 5 feet (1.52 m) receiver the signal is converted into a microseismogram that is presented on the log. Since its introduction, there have been several advances in CBL technology as well as the interpretation of the signals from the tool.

There are two key assumptions made with the interpretation of the CBL. Because the tool averages around the wellbore, there is an assumption the cement strength is uniform throughout the interval, and that the cement thickness (annular gap) is constant, usually 0.75 inch (1.905 cm). These assumptions, coupled with the use of an omnidirectional signal from the transmitter, impact the interpretation of the interpretation of the data. It is critical to understand the information received at each receiver with a basic CBL tool is an average around the well.

CBL tools are sensitive to eccentering as indicated in the following graph. Having an off centered tool will lead to the “impression” less energy has been returned to the tool and appears to be a better “bond” than is actually present. Attention to the transit time curve on the log will give the user an indication of tool eccentering. If tool eccentering is a persistent problem, it is recommended the tool be pulled out of the hole and the centralizers replaced, or additional centralizers added.

Figure A5-1 - CBL Tool response to eccentering

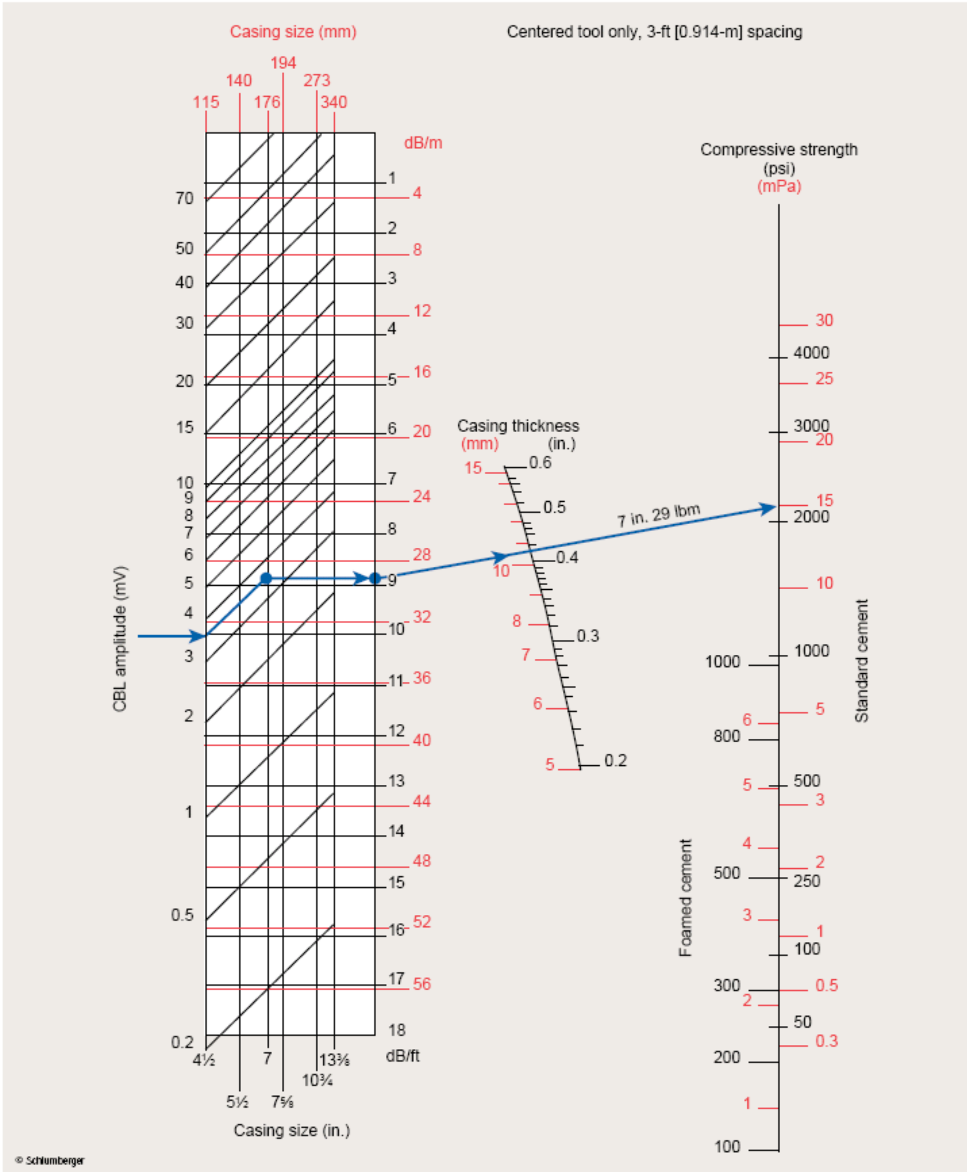


Because of the averaging of the wellbore, determining "isolation" over small intervals will be subject to error, and may become unreliable. While there can be some relative assurance of cement coverage over long sections, using a CBL to determine coverage over intervals less than approximately 50 feet (15.24 m) increases the risk of misinterpretation. There may not enough data through the averaging of the signal, coupled with the assumption of constant strength and annular gap in the well, to make definitive isolation decisions in shorter intervals.

CBL Bond Index

Pardue et al. included a description of bond index in their 1963 SPE paper. The authors state if there is no contamination of the cement, a calculation of the bond index may be used as an indication of channeling. In this same paper a nomograph was published correlating cement strength, casing size and weight, and the expected millivolt output from a log. Also found in the paper is a graph relating the % attenuation rate to that of the % circumferential bond.

Figure A5-2 - Typical CBL Nomograph



Cement bond index may be displayed on some logs rather than an amplitude or attenuation curve. Typically, percent bond or bond index is a ratio of the amplitude reading in a given section of the hole to the lowest amplitude reading in the hole:

$$BI = \frac{(A_{fp} - A_{ls})}{(A_{fp} - A_{100\%})}$$

Where:

BI = Bond Index

A_{fp} = Amplitude of free pipe

A_{ls} = Amplitude of the logged section

$A_{100\%}$ = Amplitude of 100% "bonded" pipe

Bond Index (***BI***) is the ratio of the difference between free pipe amplitude (A_{fp}) and the received amplitude in the logged section of hole (A_{ls}) to the difference between the free pipe amplitude and the lowest received amplitude ($A_{100\%}$), or what is considered to be 100% bonding. Many logs make the BI calculation, display it as part of the log, and deem 80% BI as "*good*" cement, with any value below 80% as either "*poor*," contaminated or channeled cement.

The major problem with this concept is changes in cement density and strength affect A_{ls} and $A_{100\%}$. Changes in density occur between a lead and tail cement, and strength can vary throughout the wellbore simply due to temperature differences. The assumption inherent in the calculation is the cement from the top of the well to the bottom has the same properties throughout.

Additional factors that will impact the bonding index include borehole lithology. Softer, less dense rock will yield lower amplitude, which may be interpreted as better bonding. Hard limestone and dolomites will yield higher amplitudes, which may be interpreted as poor bonding.

It is important to recognize the <u>expected</u> value for 100% bonded pipe is part of the bond index calculation. If the well has been cemented with a lightweight slurry, and the tool has not been properly set to account for the lower expected value, the bond index calculation will be wrong. For example, using the interpretation chart above, if the cement strength is assumed to be 2,100 psi (14.5 MPa), but in fact is 500 psi (3.45 MPa), the difference in the 100% amplitude signal will be 3.5 vs 12. This means the bond index calculation will show 500 psi (3.45 MPa) cement of having a bond index of 58, thus giving the impression of a large channel or no cement.

Changes in casing size and weight will impact the free pipe calculation, and must also be adjusted, particularly in wells with mixed casing strings. Often changes in bond index can simply be a result of a change in casing size and weight.

In the 1985 paper by Fitzgerald et al. the authors reproduced a graph relating the minimum cemented footage required for isolation in various casing sizes, assuming an 80% bond index. As noted, differentiating between lower-strength cement or a channel is not possible with these basic logs. It is difficult to conclude a well with a potential channel comprising 20% of the circumference of the annulus could be considered isolated, regardless of the length of the interval.

The bond index concept finds its way into many logs, from conventional CBL presentations to ultrasonic log cement maps. Some log presentations will have a color change in the cement map at specified values corresponding to an 80% bonding which again is predetermined based on an arbitrary value of what is considered "good" cement.

Because of the inherent error with the calculation of bond index, its use for determining cement quality is not recommended as a single method of cement evaluation. With conventional omnidirectional CBL logs, there is insufficient data to distinguish between channeling and lower-strength cement. With other cement map presentations, it can lead the user to interpretation errors based only on an arbitrary cut-off point on the log (See Recommendations below).

Pad-Type Tools

An improvement to the omnidirectional signal generated by the conventional CBL tools is the pad-type tools that use multiple transmitter and receiver pairs. This technology was reported by Lester in 1989 and again in 1990 by Bigelow, Domangue and Lester. The six-pad tool can provide a more detailed evaluation of the material behind the casing, and does not average the signal around the wellbore as with a conventional CBL. The pad-type tool operates at the low end of the ultrasonic spectrum, around 80 MHz. The tool can be limited in very small casing strings because of the inability to have the pads pass through small-ID casings. As reported in their paper, the color map for the tool shows 80% "Bond Rating" which then diminishes to white, intended to represent unsupported pipe.

A pad-type tool has several advantages in that, through use of directional signals, it has the ability identify channels. There remain the inherent questions relating to bond index, although these can be addressed with careful log presentation (See Recommendations below).

Pulse Echo Technology

In the 1986 paper by Sheives et al. pulse echo-type tools were introduced and have since expanded in their use. The original tools employed a set of eight transducers, which were later replaced by a family of tools employing a rotating transmitter/receiver. The tools evaluate the travel time of an ultrasonic signal through various materials in the well.

The principle of an ultrasonic tool is the measurement of the ultrasonic signal reflection coefficient (Cr) created by the materials in contact with the inner and outer surfaces of the casing.

This reflection coefficient is the ratio of the difference in the acoustic impedance of the intimately coupled material to the sum of their acoustic impedance:

$$C_r = \frac{(Z_1 - Z_2)}{(Z_1 + Z_2)} \quad (4)$$

Where

Z_1 = Acoustic Impedance of the casing, 10^6 Kg/m2 sec

Z_2 = Acoustic Impedance of the material in contact with either the inner or outer casing surface

Acoustic impedance (Z) of a material is defined as:

$$Z = V_c P_b \quad (5)$$

Where:

P_b = Bulk density, Kg/m^3

V_c = Composite velocity of a sonic signal, m/sec

Acoustic impedance is a measurable physical property of a material, regardless if the material is a solid or liquid. While knowledge of the strength of the cement is important in evaluating a conventional CBL log, ultrasonic log interpretation does not depend as heavily on knowledge of the cement strength.

Acoustic impedance measurements of a material are independent of loading conditions, and consequently, acoustic impedance will yield a more correct interpretation of the relative quality of the cement. A calculation is made of the apparent acoustic impedance of the material behind the pipe. Using this indirect measurement of the acoustic impedance of the annular material and based on the calculated impedance, a determination may be made as to the nature of the material(s) behind pipe.

Because the tool utilizes a rotating transmitter/receiver, several measurements are made on each revolution of the transmitter. Typically, 72 readings are taken per revolution with the transmitter rotating at approximately 7.5 RPS (revolutions per second).

Newer tools incorporating ultrasonic technologies send a signal at an angle to the casing, thus setting up a flexural wave. The flexural wave is used in cases where the annular material has very low impedance that may not be discernable by other tools. This can be useful in determining the presence of very lightweight or specialty cement systems in the annulus.

Cement Maps

Most cement evaluation logs incorporate some sort of cement map, a computer-generated color scheme designed to depict the "quality" of the material in the annulus. These displays may be useful for trend analysis of the job, though it must be noted the color map is highly dependent on the set points for the log. For example, setting a value for the expected impedance of cement at 4.0 would yield a very different cement map than if the expected impedance were set to 2.5.

The challenge with cement maps, as noted earlier, is the user may be led to believe that the color map indicates a true picture of what is in the annulus. In reality, it is simply a color representation of the calculated impedance values. The correlation to the quality of the material in the annulus is based on the set values for cement. Much like the bond index calculation, the expected impedance of the cement in the annulus is key to proper interpretation of the color map on the log.

Other efforts have been made to enhance the understanding of the data gathered from logs and to improve the interpretation of the cement map. Enhanced analysis methods using statistical variation processes have been developed and are used to improve the reliability of logging lightweight and specialty cements. Frisch, Graham and Griffith presented one of these techniques in 1999 and 2000.

Understanding Available Data Sets

There are multiple sets of data available for evaluation of a cement job, each with its own set of limitations. Evaluating each data set is a key step in performing a quality evaluation of a cement job. Evaluating the design of the cement job, from centralization, fluid conditioning, cement mixing and pumping is central to full analysis of the operation.

Field data in the form of pressure, rate, and density measurements of fluids pumped is very important, and if properly gathered, forms one of the more credible sets of data available. Knowing the cement was mixed to the proper density and pumped at the rates planned for the job is critical in determining the quality of the job. Evaluating the nature of the returns, whether full returns were maintained through the job, or if losses occurred (and at what time), coupled with lift pressure data aids in determining the most likely top of cement, and if the cement has covered the requisite zones.

Logging data, when calibrated and run properly, is an equally valid data set. It is when the data from a log conflicts with field data that the evaluation of the quality of a cement job becomes difficult.

Data from the job and the logging data are important and credible data sets and must be evaluated in concert. When the two data sets yield conflicting answers, efforts must be made to resolve the differences and determine a course of action. As noted, properly setting the expectations of the properties of the cement in the annulus will improve the interpretation of the data.

Overall Risks in Cement Evaluation

Thus far it is assumed the engineers have data available from cementing operation as well as logging operations. Many cases where older wells are being plugged and abandoned, there is little or no cement job data available. All too often the morning report from the rig simply said, “ran casing, cemented same.” Cement densities, or the type of cement system used is simply unavailable. In these cases, accurate cement evaluation becomes more demanding.

In the 1985 paper by Fitzgerald et.al, the authors note the recommendation for isolation using an 80% BI number should be multiplied by a factor of 3 if fracturing operations are to be performed. Using this as a baseline, with the full understanding that 80% BI is highly dependent on the cement strength chosen, then using a minimum factor of 10 times their recommendation would seem reasonable. This would mean for 7-in casing, when evaluated with a conventional CBL, the amount of cement required to obtain a “reliable” seal in the annulus would approach 300 ft.

If additional data is available, in the form of more advanced logs that do not average the signal around the wellbore, the risk of misinterpretation of isolation is reduced. Additional information, from whatever source, will aid in providing more confidence in the ultimate decisions related to wellbore isolation. Lacking sufficient data, the choice in many situations is to take the most conservative approach and attempt repair where none may be required.

The risks associated with inadequate cement evaluation can range from performing unnecessary repair work, production of unwanted fluids, inadequate stimulation operations or fluid movement in the well.

Reducing the risk of poor evaluation requires collecting additional data and evaluating the full data sets together. <u>Depending on a single set of data, be that a log or a pressure chart, increases the risk of inadequate evaluation.</u>

Conclusions:

Cement evaluation is much more than simply running some type of log into the well. Proper evaluation begins with defining the objectives of the cementing operation, determining any limitations or challenges in the design, performing the job as per the design, and then evaluating that job to assure the design and execution met the objectives. Without a clear definition of the purpose of the job, it becomes very difficult to meet the undefined expectations of the job. Reducing the risks and uncertainties in cement evaluation involves gathering as much data as possible, understanding the limitations of that data, and resolving and discrepancies between data sets.

Cement evaluation is highly dependent on the material in the annulus. Cement properties such as density and strength are key inputs into calibrating the logs. Without knowledge of what is expected in the annulus, the risks of misinterpretation increase. When performing cement log evaluations, the engineer must understand the limits of the tools being employed as well as the assumptions that go into the logging display.

Recommendations:

Although these recommendations address cement evaluation for all types of production and/or injection wells, they are particularly important for assuring the integrity of longer-term CO_2 storage wells. Proper cement evaluation should not be limited to a single set of data, for example from a conventional bond log. The beginnings of cement evaluation start with the objectives of the job, the type of cements used in the wellbore and an evaluation of the operational parameters during the job. These must be matched with an appropriate cement evaluation technique to properly evaluate the cement sheath. As noted in this section, different logs will give different data and can readily be used in combination with each other.

Operators should not depend on a single data set for the cement evaluation, but rather employ all of the available data including service company design reports, operational records, and the electronic logging results. When selecting the type of cement evaluation log to use, consider the limits of the tools based on the slurry design and the well conditions. Proper cement evaluation is not a one size fits all recommendation but requires sound engineering practice to perform.

Basic CBL tools will offer the least amount of information of any of the evaluation logs, though may be appropriate in conjunction with more sophisticated logs. Calibrating the expected tool response with laboratory data from cement slurry design used on the well rather than using a default value is essential to quality log evaluation.

Do not use bond index as a measure of the effectiveness of the cement coverage.

A5.4 DESCRIPTIONS OF REGULAR PORTLAND CEMENTS AND SPECIALTY CEMENTS

Table A5-1 - Regular Portland cements are briefly described as per API Specification 10A and ASTM Specification C150. The API specifications are reviewed annually and revised according to the needs of the oil industry.

API Class (ASTM Type)	*Description*
Class A (Type I)	Portland cement for use where no special properties are required. Processing additions may be used in the manufacture of the cement, provided the additives meet the requirements of ASTM C465. Class A cement is available only in ordinary (O) grade and is applicable from surface to 6,000 feet (1,830 m) depth.
Class B (Type II)	Portland cement with sulfate-resistant properties to prevent deterioration of the cement from sulfate attack in the formation water. Processing additives may be used as long as in compliance with ASTM C465. Available in both moderate sulfate-resistant (MSR) and high sulfate-resistant (HSR) grades and is applicable from surface to 6,000 feet (1,830 m) depth.
Class C (Type III)	Intended for use when high early strength and/or sulfate resistance is required. Processing additives may be used as long as in compliance with ASTM C465. Available in ordinary (O), moderate sulfate-resistant (MSR), and high sulfate-resistant (HSR) grades and can be used in the depth range of 6,000 to 10,000 feet (1,830 to 3,050 m).
Class G	No additions other than calcium sulfate or water, or both. Shall be blended with the clinker during manufacture of Class G cement. Class G is a basic oil well cement and is available in MSR and HSR grades. Depth range is between 10,000 and 14,000 feet (3,050 to 4,270 m). Class G is ground to a finer particle size than Class H.
Class H	No additions other than calcium sulfate or water, or both. Shall be blended with the clinker during manufacture of Class H cement. Used as a basic oil well cement and is available in both MSR and HSR grades. Depth range is from surface to 8,000 feet (2,440 m). Note: Surface areas based on the Blaine test method for Class G and Class H cements typically lie in the range of 300 to 400 and 220 to 330 m_2/kg respectively.

In addition to the API and ASTM classified cements, various special types of cement materials (**specialty cements)** can be used for primary and remedial cementing operations. Many of these special cements are developed for specific applications. Some are a dry blend of API cements with a few additives, while others are cements containing other chemical characteristics. The composition, quality and uniformity of these cements are often kept confidential by the supplier.

Table A5-2 - Description of special cements (modified from Contek/API, 2008 and Nygaard, 2010)

Name	**Description**
Pozzolanic- Portland Cement	Pozzolanic materials are often dry blended with Portland cements to produce lightweight (low density) slurries for well cementing applications. Pozzolanic materials includes any natural or industrial siliceous or silica-aluminous material, which in combination with lime and water, produces strength-developing insoluble compounds similar to those formed from hydration of Portland cement. The most common sources of natural pozzolanic materials are volcanic materials and diatomaceous earths. Artificial materials are usually obtained as an industrial byproduct, or natural materials such as clays, shales and certain siliceous rocks. Adding pozzolanic materials to API or ASTM cements reduces permeability and minimizes chemical attack from some types of corrosive formation waters.
Gypsum cement	Gypsum cement is blended cement composed of API Class A, C, G or H cement and the hemi-hydrate form of gypsum. In practice, the term "gypsum cements" normally indicates blends containing 20% or more gypsum. Gypsum cements are commonly used in low temperature applications since it sets rapidly, has high early strength and positive expansion. Due to their high ductility and acid solubility, they are not considered suitable for CO_2 service.
Microfine cement	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. Have average size of 4 to 6 microns and maximum particle size of 15 microns, which enables them to harden fast and penetrate small fractures. An important application is to repair casing leaks in squeeze operations, particularly tight leaks that are inaccessible by conventional cement slurries because of penetrability.
Expanding cements	Cement slurries with significant quantities of NaCl or KCl (also known as "salt cements") are used during cementing across massive salt formations or water-sensitive zones to prevent salt dissolution and clay swelling. Primary application is to improve bond of cement to pipe and formation. Expansion

Name	Description
	can also be used to compensate for shrinkage in neat Portland cement
Calcium aluminate cement	High-alumina cement (HAC) or calcium aluminate cements (CAC) are used for very low and very high temperature ranges. Several high alumina cements (with alumina contents of 35 to 90%) have been developed. Setting time for these cements is controlled by the composition and no materials are added during grinding. These cements can be accelerated or retarded to fit individual well conditions, although the retardation behavior is different than for Portland cements. Addition of Portland cement to this cement results in very rapid hardening, therefore must be stored separately. Calcium aluminate phosphate blended with a few additives produce cements that are highly resistant to the corrosive conditions found in wells exposed to wet CO_2 gas or CO_2 injection wells.
ThermaLock™	ThermaLock cement is specially formulated calcium phosphate cement that is both CO_2 and acid resistant. This cement is well suited for high temperature geothermal wells and has been laboratory tested and proven at temperatures between 60^0 C to as high as 371^0 C. It is also being marketed for CO_2 EOR and CO_2 storage wells.
Latex cement	Latex cement is a blend of API Class A, G or H with polymer (latex) added. Latex-modified cement systems provide several benefits: improved pumpability, increased tensile strength and increased bonding between steel/cement and cement/formation interfaces. Styrene butadiene latex additive is effective in preventing annular gas migration. It is well known that CO_2-laden waters can destroy the structural integrity of set Portland cements. As a result of the reaction chemistry, the net result is a leaching of the cement material from the cement matrix, an increase in porosity and permeability, and a decrease of compressive strength. Downhole this translates to a loss of casing protection and zonal isolation. Addition of pozzolans and latex can reduce the corrosion rate by as much as 50%. A well distributed latex film may protect the cement from chemical attack in some corrosive conditions, such as formation waters containing carbonic acid. Latex also imparts elasticity to the set cement and improves the bonding strength and filtration control of the cement slurry.
Resin/plastic/synthetic cements	Resin or plastic cements also known as organic polymer epoxy cements are specialty materials used for selectively plugging open holes, squeezing perforations, and the primary cement for waste disposal wells, especially in highly aggressive acidic environments. A unique property of these cements is their capability to be squeezed under applied pressure into permeable zones to form a seal within the formation.
Sorel cement	Sorel cement is magnesium oxychloride cement used as a temporary plugging material for well cementing. The cement is made by mixing

Name	Description
	powdered magnesium oxide with a concentrated solution of magnesium chloride. Sorel cements have been used to cement wells at very high temperatures (up to 750^0 C).
EverCRETE™	EverCRETE CO_2 is marketed as CO_2-resistant cement that can be applied for CO_2 storage wells as well as for CO_2 EOR wells. EverCRETE cement has proven highly resistant to CO_2 attack during laboratory tests, including wet supercritical CO_2 and water saturated with CO_2 environments under downhole conditions. It can be used for both primary cementing as well as for plugging and abandoning existing wells.
Self-Healing and CO_2-Resistant Cement	A new promising technology consists of an engineered particle size distribution (ESPD) blend containing a reactive material that swells upon contact with CO_2. This swelling allows the closure of micro-fissures and/or the reduction of the micro-annulus, which heals the cement sheath and reestablishes the integrity of the well. This technology has been successfully deployed in an onshore well in Brazil (Engelke et al, 2017)
Freeze-protected Arctic Cements	During drilling and completion, a permafrost formation must not be allowed to thaw (external freeze-back leads to higher collapse loads at base of permafrost). Melting can cause the thawed earth to subside, particularly in the upper 200 feet of the well. Also, below the base of the permafrost, casing experiences tension while above it experiences compression and causes the base to be uplifted. Desirable to use a quick-setting, low-heat-of-hydration cement system that will not melt the permafrost and develop sufficient compressive strength (without freezing) at temperatures as low as 20^0 F. Casing strings must be cemented to surface, or a non-freezing fluid (oil-based or glycol) placed in the annulus, to prevent casing failure (known as internal freeze-back) owing to the expansion of water upon freezing. There is also a need for complete displacement of water-based fluids. Systems that perform in permafrost are: calcium aluminate cement; gypsum-Portland cement blends (with NaCl as a mix-water depressant); and ultra-fine Portland cement. In order to prevent contact between alumina and Portland cements, extended Class G systems are widely used today.
Ultralow-density/Foamed cements	Formations that have a low fracture gradient (FG), or are highly permeable, cavernous or vuggy are difficult to cement since they are unable to support the annular hydrostatic pressure of a conventional cement column and ultralow density cements (less than 10 pounds per gallon -ppg) provide a solution to such problems. Foamed cements are made of a base conventional cement slurry (15-16

Name	Description
	ppg), nitrogen gas, surfactant and other materials to provide foam stability. Foamed cements are less expensive than engineered particle size (EPS) systems containing glass microspheres or cenospheres; however, special equipment is needed at the wellsite to inject the nitrogen or air into the base slurry. Foamed cement has several advantages in addition to its low density: relatively high compressive strength developed in a reasonable time; less damaging to water-sensitive formations; its compressible nature prevents fluid influx and annular gas migration; ability to cement past zones experiencing total losses; system density can be adjusted during the job by simply changing the gas concentrations; controlling shallow gas flows below the mudline in deep water wells. Stability of foamed cement is critical, if unstable – gas bubbles will coalesce and migrate through the slurry. With complete gas break-out and upward migration – will result in loss of overbalance and a loss of volume and a lower TOC (Top of Cement).

APPENDIX 6 - PLUGGING AND ABANDONMENT OF WELLS

CO_2 geological storage projects will likely incorporate a range of well types, from injection and production wells, to abandoned and previously completed wells. While the risks for leakage from newly drilled and completed wells are expected to be less, due to improved technology and regulations, older wells that were improperly constructed (although in compliance with existing regulations at that time) and that may or may not have been improperly abandoned (again may have been in compliance with existing regulations at that time) may pose a greater risk of escape of CO_2 and formation fluids to overlying formations or to the surface. Also, legacy wells were not designed for handling CO_2.

Storage in deep saline aquifers may also pose a lower risk (due to lower number of wellbores encountered) than those encountered in oil and gas fields. Depleted oil and gas reservoirs are likely to incorporate a greater number of wells penetrating the reservoir cap-rock due to the historical exploitation of these fields. Seepage, migration and leakage can occur through faults and fractures in the cap-rock above the reservoir and/or through improperly plugged and abandoned existing old oil and gas wells. (For the context of CO_2 geological storage, natural CO_2 migration from the storage reservoir, usually along faults which can reach the surface forming CO_2 vents to the atmosphere is termed **seepage**, movement of CO_2 or other fluids through permeable strata which covers designated reservoirs, aquitards and caprocks (at very low levels) is termed **migration**, and **leakage** is the movement of CO_2 or other fluids out of a storage complex. This covers geological formations and wellbores, and in reality rates of leakage could be too low to accurately detect.).

Therefore a good understanding of well abandonment and remedial measures and current abandonment practices and regulatory requirements are necessary to assure safe and secure long-term storage of CO_2 in the subsurface reservoirs. A variety of techniques are employed around the world to facilitate well abandonment and state and federal regulatory agencies may specify the exact requirements for doing so. Table

A6-1 below describes each plugging method and the drawbacks and limitations of each method.

Table A6-1 - Description of abandonment methods

Abandonment Method	Description	Benefits/Limitations
Balanced Plug	The more common method of abandonment, with the tubing placed at the target plug depth and the cement slurry is then injected onto a bridge plug device which forms the plug base. Cement is then pumped into the annulus until it is equal to the level inside the casing.	One of the simplest techniques. Main limitation is potential for cement contamination, which can be minimized by use of best practice and use best suited plug base materials.
Cement Squeeze	Squeeze cementing involves pressurized forcing of cement at a pre-determined depth coinciding with perforations in the casing. The pressure forces the liquid of the slurry into the formation, leaving the cement to form a seal	Used for remedial cementing after a flawed or damaged primary cement job. Since exact quantity of cement required cannot always be calculated, may lead to excess cement entering the casing above the packer. This may lead to sticking of tubing in hole, preventing future removal.
Dump Bailer	A known quantity of cement is lowered into the wellbore on wireline, and the bailer is activated when it reaches the desired depth, just above the bridge plug and raising the bailer releases/dumps the cement.	The stationary nature of the cement during the descent can lead to premature setting, therefore more suited to setting plugs at shallower depths.
Two-plug	Top and bottom plugs are set at calculated depths, the lower plug cleans the well as it is lowered, and the cement can then be placed with minimal contamination from other fluids.	Allows maximum accuracy of placement with minimum cement contamination. Isolation of cement slurry from other fluids ensures predictable cement performance.

A bridge plug is a downhole tool that is located and set to isolate the lower part of the wellbore. Bridge plugs may be permanent or retrievable, enabling the lower wellbore to be permanently sealed from production or temporarily isolated from a treatment conducted on an upper zone. Cement retainers are similar except that they are designed to allow cement to be pumped below the tool.

API Bulletin E3 "Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations", 1993 gives additional guidelines on plugging and abandonment requirements. An update to this document is currently being developed by API. The requirements for the Texas Railroad Commission for plugging and abandonment for Class II CO_2 EOR wells are given in Texas Administrative Code (TAC), Rule § 3.14 and for Class VI Storage wells are given in Section 7.1.

In general terms, the procedure for CO_2 EOR wells involves:

1. *Setting the ON/OFF plug in the tubing string to the OFF position,*

2. *Pulling the string,*

3. *Setting a cement retainer or bridge plug,*

4. *Placing sufficient cement to isolate the producing formation (squeezing through the cement retainer or placing a cement plug on top of a bridge plug), and,*

5. *Depending on the number of horizons in the well, repeating steps 3 and 4 for each.*

6. *Positive and/or negative pressure tests to verify the integrity of the cement and mechanical plugs.*

The foregoing plug and abandonment procedure is used to isolate the production/injection formation from other formations and to protect ground water resources from potential contamination.

A6.1 RECOMMENDED BEST PRACTICE FOR WELL ABANDONMENT FROM A CCS PERSPECTIVE

The recommended best practice for well abandonment from a long-term storage integrity perspective involves (IEAGHG):

- *Advanced materials; improvement in the capacity of wellbore sealants to isolate stored CO_2 can be applied during drilling, completion, workover and abandonment operations*

- *Reduced cement permeability and reactivity: either by reducing the water to cement ratio or the addition of specialist materials which also allows the slurry density to be adjusted over a range of values*

- *Use of non-Portland cements: these are less reactive with wet CO_2, however they are not compatible with Portland cements, and cross-contamination must be avoided. They also entail higher costs than Portland based cements*

- *Self-healing cements and swelling packers: these contain specific additives that react with the fluids present to effectively block cracks and annuli to prevent flow.*

Swelling packers are used in case of cement failure – they are designed to swell upon contact with hydrocarbons, water or both.

Carlsen and Abdollahi (2007) describe a methodology for abandonment that is shown in Figure A6-1. The process involves removing the tubing and packer before placing a cement plug at the bottom of the well, and then injecting a specialized fluid into the reservoir to clog the near-well area and displace the CO_2 to minimize contact between CO_2 and wellbore materials. The casing is then milled at the level of the cap-rock and cement injected into this open section to prevent leakage along micro-annuli between casing and cement elements. The well is then filled with non-corrosive completion fluid. If secondary seals are present, then an additional cement barrier should be placed at this point.

Figure A6-1 - CO_2 storage well before (left) and after abandonment (right) according to the methodology described by Carlsen and Abdollahi (SINTEF 2007)

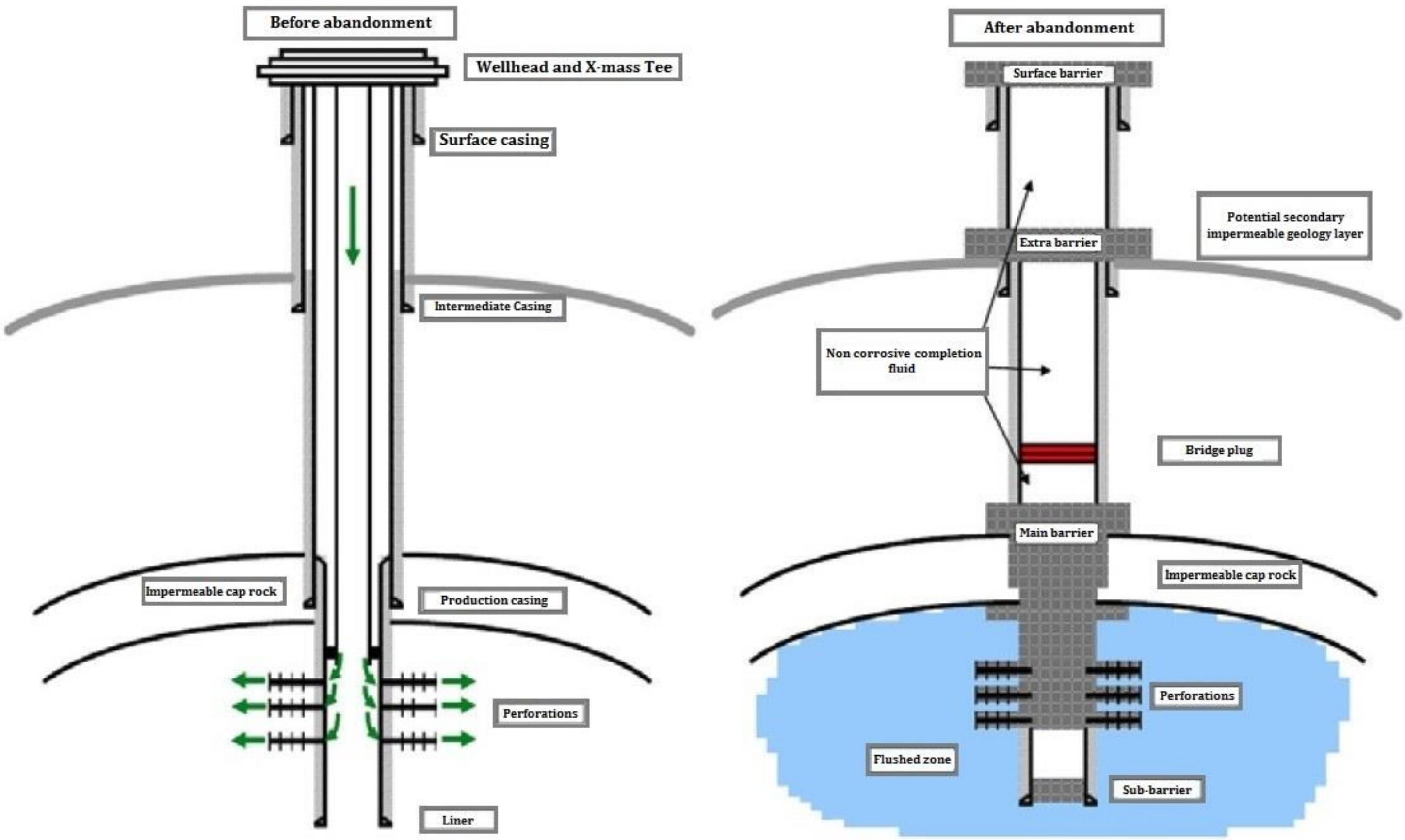
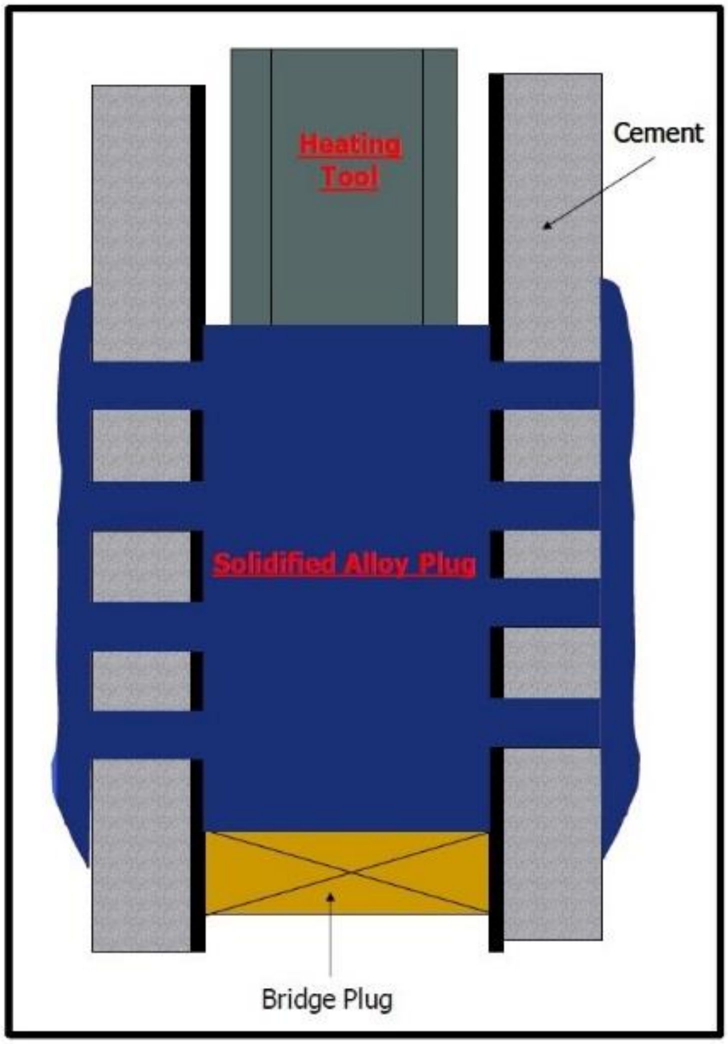


Figure A6-2 - Schematic of using metal alloy plug to seal and abandon production zone (Canitron, 2008)



Removing the casing in certain areas is another recommended practice to mitigate leakage caused by poor bond or de-bonding between casing and cement. Besides, CO_2 can attack both steel and cement and create leakage paths. In the West Texas field case, it has been seen that reactions have occurred at the casing cement interface and the cement formation interface. Before the final cement squeeze and plug is set, a CO_2-resistant polymer may be injected in the near wellbore region to prevent CO_2 from coming in contact with the cement after injection. CO_2 resistant cements are recommended to seal the reservoir as the cement will be exposed to the CO_2 in the future. An open hole completion will reduce the need for milling the casing and may be a simplified solution where appropriate.

APPENDIX 7 - WELL INTEGRITY MANAGEMENT SYSTEMS (WIMS)

A7.1 WELL INTEGRITY MANAGEMENT SYSTEMS

A Well Integrity Management System (WIMS) is a solution to define the commitments, requirements and responsibilities of an organization to manage the risk of potential loss of well containment over the well's lifecycle. The tasks necessary to establish and maintain well integrity, and the roles accountable and responsible for delivery, are specified in a WIMS document. To implement the WIMS, various forms from simple solutions utilizing a spreadsheet, to complex electronic management systems are utilized.

The objective of a WIMS is to specify requirements necessary for delivery of well integrity, including:

- *Well integrity refers to maintaining full control of fluids within a wellbore at all times, in order to prevent unintended fluid movement or loss of well control*
- *Well integrity policy defines commitments and obligations to safeguard health, safety, environment, assets, and reputation*
- *WIMS assures that well integrity is maintained throughout a well's lifecycle by the application of a combination of organizational, technical, and operational processes.*

Commercially available WIMS software/systems include:

- *Woodgroup - Intetech-IQRA*
- *Exprosoft – Well-Master*
- *Oxand – Simeo risk based assessment*
- *RIFTS – mainly artificial lift, structural under development (JIP)*
- *OREDA – Offshore and Onshore Reliability Data*
- *Halliburton – Landmark – Decision Space Well Integrity (DSWIM)*
- *Yuit SWIS – Smart Well Integrity System*
- *Peloton – WellView10 – Enhanced with Well Barrier and Integrity Program*

A7.2 ELEMENTS OF THE WELL INTEGRITY MANAGEMENT SYSTEM

- *Wells ownership over the lifecycle for wells that are:*
  - *Developed*
  - *Acquired*
  - *Divested*
  - *Suspended*
  - *Shut-in*
  - *Operated*
  - *Exploration*
  - *Abandoned by company*
- *Organizational structure with roles:*
  - *Responsibilities*
  - *Competencies*
- *Risk assessment with a risk register that:*
  - *Defines the risk*
  - *Mitigations for the hazards that are to be managed*
- *Well types with:*
  - *Well barriers*
  - *Well barrier envelopes that control hazards*
- *Performance standards that:*
  - *Define the requirements to maintain the well barriers within its operating limits*
- *Well barrier verification that:*
  - *Assures the mechanical status of the well is maintained on a defined risk*
- *Underlying processes like:*
  - *Reporting*

- *Documentation*
- *Management of change*
- *Continuous improvement*

A7.3 RISK ASSESSMENT

A Risk Assessment is a procedure to determine the quantitative or qualitative value of a risk or threat to a specific situation. Risk can be defined as a combination of both the severity of the consequences of an event and the likelihood or probability that the event will occur. Risk increases with increasing severity and/or likelihood. It is an industry accepted practice to require prevention or mitigation for significant and/or high risk category wells.

One vey general but accepted definition for a high risk well is: "A well in which the last barrier is under threat of being compromised". Each company should create their own specific definitions for well risk based on operating area, well stock, and risk tolerance. There are several risk assessment methods available and a few are summarized below:

A7.3.1 Quantitative Risk Assessment (QRA)

Quantitative Risk Assessment (QRA) is a risk assessment method that is based on numerical probability using historical data and reliability models. This method is commonly used in risk assessment of hydrocarbon processing facilities and oil pipeline systems. The challenge for using a QRA for well integrity is the availability and reliability data for use in a risk model. Even with a sound model, if the initial and boundary conditions are not correct, the prediction risk may be flawed.

A7.3.2 Qualitative Risk Assessment

A Qualitative Risk Assessment is a more conventional method for well integrity and it is primarily based on experience and the application of good engineering judgement. Qualitative Risk Assessments are easier to execute but are limited by the experience and knowledge of the people performing the assessment.

A7.3.3 QRA/Qualitative Hybrid

Due to a lack of well integrity reliability data for QRAs, many well integrity risk assessments are QRA/Qualitative hybrids based on known failure data, rules, procedures and risk matrices rather than using straight qualitative or QRA analyses.

A7.3.4 Considerations for Risk Assessments

Some of the factors/considerations for managing risks from a well or wellfield are:

- *Outflow potential to surface or subsurface environments*
- *Fluid types and composition, H_2S, CO_2, gas, oil, water etc.*
- *Location: subsea, offshore, swamp, land, urban, natural reserve etc.*
- *Earth model, subsidence, earthquakes, permafrost, deep water, high pressure high temperature (HPHT) etc.*

A7.4 ENVIRONMENTAL HEALTH AND SAFETY PLAN FOR CO2 INJECTION (AFTER JARRELL ET AL, 2002)

Overall, the advantages of CO_2 injection outweigh the disadvantages. Although CO_2 is a greenhouse gas and venting should be minimized, large scale releases to the atmosphere normally do not occur because produced CO_2 is reinjected into the reservoir for enhanced oil recovery or into a saline aquifer for long-term storage. Due to the unique characteristics of CO_2 previously discussed, the preparation and implementation of a written environmental, health and safety (EHS) plan is a pre-requisite prior to initiation of any CO_2 injection project.

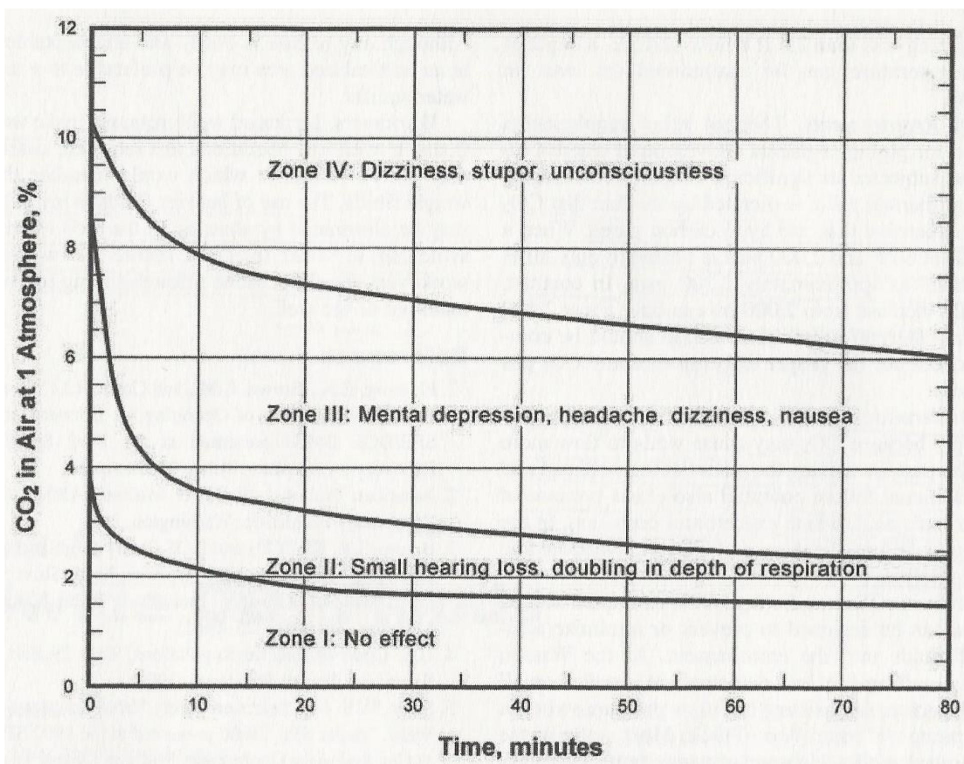
As used in EOR and storage, CO_2 in high concentration can pose serious safety concerns – asphyxiation, atmospheric hazard control, noise level (during pressure relief), frostbite, hydrates/ice plugs, and high pressures.

A7.4.1 The Dangers of CO_2

At normal conditions, the atmospheric concentration of CO_2 is 0.04% (400 ppm), a non-toxic amount. Most people with normal cardiovascular, pulmonary-respiratory, and neurological functions tolerate exposure of up to 0.5% to 1.5% CO_2 for one to several hours without harm. Higher concentrations or exposures of longer durations are hazardous and may cause asphyxiation if the concentration in the air is reduced to below the 16% required to sustain human life (Figure A7-1). The current U.S. standard for the maximum allowable concentration of CO_2 in the air for eight continuous hours of exposure is 0.5%, while 3% is the maximum concentration that operating personnel can be exposed to for a short period of time. At concentrations above 20%, death can occur in 20 to 30 minutes (Fleming et al, 1992).

People exposed to CO_2 who are still conscious and alert should be taken to fresh air and kept under observation. Unconscious or disoriented persons should be moved to fresh air and be treated with a respirator or receive cardiopulmonary resuscitation (CPR), as warranted. First aid always should be followed by a professional medical examination.

Figure A7-1 - Exposure to CO_2 Hazards (Jarrell et al, 2002)



A7.4.2 Atmospheric Hazard Control

- *Venting of CO_2 should be minimized, although for safety and other operational reasons, it sometimes cannot be avoided. Adequate ventilation must be provided when CO_2 is discharged into the air, and CO_2 vents should be located at high elevations and in areas where maximum dispersion can occur.*

- *Due to its high density, released CO_2 will flow to low elevations and collect there, especially under stagnant airflow conditions with high concentrations persisting in open pits, tanks and buildings. For this reason, operators should install monitors wherever CO_2 might concentrate and should regularly check and calibrate the equipment. It is also recommended to have portable monitors, since CO could collect in so many places and installing a fixed monitor at every location would not be economically feasible.*

- *Fixed CO_2 monitors should sound an alarm and/or turn on safety equipment such as ventilation fans when activated. They also may activate emergency shut-down procedures if the concentration is particularly high. There are at least three types of CO_2 monitors available: tube reaction (similar to a Drager H_2S monitor), thermal conductivity and nondispersive infrared.*

- *If the presence of CO_2 is suspected in areas where the air is stagnant such as sewers, wells, and closed-off rooms, personnel entry should be carefully planned according to written operating procedures that should include preventing additional CO_2 from entering the area, clearing the area by forced ventilation, and testing and continuously monitoring the atmosphere to detect an oxygen deficiency.*

- *Where it is not feasible to install ventilation, personnel entering the area should be trained and proficient in the use of appropriate respiratory equipment (airline respirators or self—contained breathing apparatus (SCBA).*

A7.4.3 Noise Levels

- *High noise levels can result whenever pressure is relieved, such as when vessels are evacuated for maintenance or when CO_2 is bled from a wellhead before switching to water injection. Hearing protection must be worn whenever the noise exceeds 90dB for an extended period of time (U.S. Occupational Safety and Health Standards).*

A7.4.4 Frostbite

- *Frostbite (freeze burn) is a serious injury that can result from contact with cold surfaces, solid CO_2 (dry ice), or escaping liquid CO_2. Any CO_2 pressure drop can cause a hazardously cold condition, and frost is not uncommon on wellheads and flowlines where a large amount of CO_2 is being produced.*

- *When containment pressures are released accidentally and a small amount of CO_2 turns to gas, the temperature of the remaining liquid immediately drops to approximately -101^0 F (-74^0 C), nearly the temperature of solid dry ice. Personnel should avoid entering a CO_2 vapor cloud not only due to the high CO_2 concentrations, but also due to the danger of frostbite. Precautions such as wearing gloves and eye goggles must be taken.*

- *Should frostbite occur, the most important element of treatment is speed, since the longer a body part is frozen the greater the likelihood for it to be destroyed. Treatments for frostbite are found in many publications.*

A7.4.5 Hydrates/Ice Plugs

- *Hydrates, or ice plugs, can form in the piping of facilities and flowlines, especially at pipe bends, depressions, and locations downstream of restriction devices.*

- *Subfreezing temperatures are not required for hydrates to form. Hydrates are slushy crystals of CO_2 and water that may form when the temperature drops below 55^0 F (12.8^0 C), when pressures are below 5,000 psi (34.5 MPa). Using glycols, alcohols, and other freeze depressants can prevent or reduce hydrate formation. Installing heat tracing on pipes also is effective.*

- *First indication of an ice plug will be an abnormally low pressure on the downstream side of the blockage, and when this is suspected, the section of the line with the suspected ice plug should be isolated as soon as practical. Pressure should be maintained as close to equal on both sides of the plug to prevent it from being dislodged by a pressure differential and then damaging equipment downstream. Applying heat to the exterior of the pipe in the form of heating pads or hot air blowers can melt the plug.*

A7.4.6 High Pressures

A principal source of danger in a CO_2 facility is the high pressure (generally above 1,100 psi – 7.58 MPa) at which CO_2 is transported and injected. High pressure is particularly dangerous with CO_2 because of CO_2's high coefficient of thermal expansion – a small change in temperature can cause a large change in pressure.

To prevent over-pressurizing the system (which could cause emergency releases or burst pipes), the CO_2 must never be trapped or blocked. Following these rules helps maintain proper pressures:

- *Do not close more than one flow valve at a time without proper venting*
- *Prevent formation of ice or hydrate plugs*
- *Do not pressurize the system above the weakest part of the system*
- *bury piping at least 2.5 feet (0.76 m) below surface, a depth at which constant temperature can be maintained (at least in moderate latitudes) (Boone, 1985).*

A7.4.7 Thermal Relief Requirements

Thermal relief requirements must be considered for piping segments aboveground where CO_2 may be trapped and subjected to significant temperature changes. The requirement for thermal relief is dictated by the fact that CO_2 is more thermally expansive than are hydrocarbon gases: When a sample of pure CO_2 at 600^0 F (315.5^0 C) and 2,000 psi (13.8 MPa) is heated to only 800^0 F (427^0 C), the pressure increases to approximately 3,300 psi (22.8 MPa). In contrast pure methane would increase from 2,000 psi (13.8 MPa) to only about 2,180 psi (15.0 MPa). Emergency and thermal relief systems also should be computer modeled to check for the proper dispersion of any CO_2 gas that may be released.

A7.4.8 Wellhead Considerations

Well problems often accompany CO_2 injection simply because CO_2 may cause production wells to flow more than they have in the past, increasing the potential for wellhead and tubing failures. Additional failure potential also exists because of the presence of carbonic acid, which exacerbates corrosion. In the event of a catastrophic failure, the release of CO_2 and wellbore and reservoir fluids is possible.

To prevent accidental releases of fluids into the environment, equipment system designs include:

- *Installation of stuffing-box detectors on all wells. These leak detectors and existing high/low pressure switches are connected to pump off controllers (POC). Wells are also equipped with a high-performance butterfly safety shutdown valve to which the POC is connected. Pressure switches operate these valves through electrohydraulic actuators (D'Souza et al, 1995)*

- *The Wasson Denver Unit (Fleming et al, 1992) uses a similar system in which a vibration detector on the beam unit shuts down the pump in the event of a rod or wrist-pin failure. In addition, injector valves are programmed to close upon detection of low tubing pressure, low injection line pressure, high casing pressure, and other potentially dangerous conditions.*

- *The status of the safety equipment should be continuously monitored to enable quick detection of leaks and blocked flowlines in wells where casing integrity may be compromised.*

A7.4.9 Protection of Near-Surface Waters

In some cases, operators have installed casing pressure relief valves to protect shallow freshwater zones. These valves ensure that in high casing pressures, the result is a surface release rather than an underground blowout. Although any release is costly and unacceptable, a surface release in an uninhabited area may be preferable to a release into a freshwater aquifer.

A7.4.10 Populated Area Wells

For wells in populated areas special measures can be taken to protect the public from an accidental CO_2 release. The entire well location can be fenced and monitored 24 hours a day via computer assisted alarms; atmospheric dispersion models can be done to verify that CO_2 releases in the area pose no danger at maximum anticipated rates.

A7.4.11 Workovers

Increased well pressures make workovers more difficult. If well-kill operations are required sodium chloride brine may not be adequate, requiring the use of heavier-weight fluids. The use of heavier weight fluids in injection well workovers may be eliminated by shutting in the well to let it stabilize, or by switching to water injection before the workover. If possible, workovers should be done through tubing to avoid pulling equipment out of the well.

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