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Carbon Dioxide Enhanced Oil Recovery Injection Operations Technologies

(Poster Presentation)

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Abstract

Over the past 35 years, the oil and gas industry has developed many technology improvements and operating practices for injecting carbon dioxide (CO_2) for enhanced oil recovery (EOR). Over this time, the US oil and gas industry has operated over 13,000 CO_2 EOR wells, over 3,500 miles of high pressure CO_2 pipelines and has injected over 600 million tons of CO_2 without any significant safety or environmental endangerment events. Today, the US produces over 245,000 barrels of oil per day as a direct result of CO_2 EOR.

This presentation will describe many of the technical improvements and operational practices that have been developed as a result of the oil and gas industry's experiences with CO_2 EOR. When these technologies and practices are applied, operators can expect facility and wellbore integrity at levels equivalent to those seen for conventional oil and gas operations.

Many of the technologies and practices that have been developed for CO_2 EOR may have applicability in carbon capture and storage (CCS) projects, recognizing however, that each project should be designed to meet its site specific conditions. The CO_2 EOR experiences of the oil and gas industry represent the largest collective base of technical information available on CO_2 injection and, as such, provide valuable information for development and implementation of CCS field projects as they move forward.

Keywords: Enhanced Oil Recovery, CO2, Carbon Dioxide, Oil and Gas Production Technology, CCS, Carbon Capture and Storage

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1. Introduction

The oil and gas industry has been producing, capturing, transporting, and injecting carbon dioxide (CO_2) for enhanced oil recovery (EOR) for over 35 years. The experience gained over this time will prove invaluable as carbon capture and storage (CCS), a technically similar process, moves forward.

In the United States alone, the oil and gas industry operates over 13,000 CO_2 EOR wells (injection and production) with a degree of reliability comparable to that of conventional oil and gas wells. In developing CO_2 based EOR, the industry's improvements in design and operating practices for CO_2 EOR wells have been significant (table 1). Particular areas of design improvement include:

- Selective use of corrosion resistant materials and alloys for surface piping, metal component trim and specialty coating applications
- Use of CO_2 resistant elastomers, Teflon, and nylon for packer elements and seals
- Use of novel tubular coatings or liners using plastic, epoxy resin or fiber glass/resin materials
- Use of specialty cements and additives
- Use of automatic controls and real time monitoring systems

Careful selection and prudent use of these materials and associated operating practices has led to significant improvements in wellbore and production equipment integrity and longevity, relative to initial implementation efforts that were based on the use of standard oil and gas equipment and practices developed for hydrocarbon-produced water systems alone. Today, CO_2 EOR operators routinely achieve wellbore integrity levels similar to those seen for conventional oil and gas production operations. Additionally, there are no indications that geologic integrity (containment) at CO_2 EOR fields is at risk.

2. Background

The solvent characteristics of supercritical CO_2 have long been recognized. 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. Thermodynamically, CO_2 is said to be in a supercritical state when it exists at pressures and temperatures above 1,070 psi (7.38 MPa) and 88^{o}F (31^{o}C), respectively, and exists as a dense phase fluid.

Injection of supercritical CO_2 was first identified as a potential means for improving oil recovery in aging fields in the early 1950s. Field tests conducted in the 1960s demonstrated the concept of CO_2 EOR. In 1972, the first commercial scale injection of CO_2 for EOR was initiated in the SACROC (Scurry Area Canyon Reef Operators Committee) Unit of the Kelly-Snyder field in West Texas. This project continues in operation today and is the world's largest CO_2 miscible flood EOR project both in terms of CO_2 injection volume and oil production.

The early successes of CO_2 based EOR projects has led to over 110 similar projects, most in West Texas, but several in other parts of the world as well. Over 2 billion cubic feet (BCF) per day of CO_2 are injected in West Texas alone and approximately 250,000 barrels of oil per day are produced as a result.

The most common approach to conducting CO_2 based EOR is by the injection of alternating cycles of CO_2 and water, commonly known as the water alternating gas or WAG process. The WAG process facilitates optimal use of injected CO_2 by:

- Displacing crude oil during the water injection cycle that has been made miscible with CO_2 from the previous CO_2 injection cycle
- Controlling the vertical stratification of CO_2 by suppressing its tendency to buoyantly rise to the top of the receiving formation, thereby increasing ultimate oil recovery

WAG cycles are repeated many times over the life of an EOR project. Injected CO_2 that is co-produced with the crude oil as a normal part of the EOR process is separated and recycled. In a mature project, over half of the CO_2 used in a project may be recycled CO_2.

Operationally, the WAG process creates a worst case scenario from a wellbore and surface facility integrity standpoint due to the mixing and chemical reaction between CO_2 and water. Specifically, CO_2 reacts with water, (both injected water and naturally occurring formation water), to form carbonic acid which, over time, can produce severe corrosion in both the injection and production sides of a facility (pipelines, wellheads, tubing, separators). Managing the adverse effects of carbonic acid has been the focus of the vast majority of the technology development that has occurred with CO_2 EOR. To a secondary degree, technology developments have been devoted to identifying swell resistant materials to circumvent the effect of CO_2 permeation in seals and packers.

Managing the effects of CO_2 aqueous solutions on a daily basis is a critically significant difference between CO_2 EOR and CCS operations. Although no specifications have been established for the quality of the CO_2 transported in new or existing pipelines for CCS projects, it is very likely that, because of both thermodynamic and material considerations, pipeline operators are very likely to require that it be shipped and injected in an essentially dry state. Thus, concerns about corrosion in the injection system are inapplicable. Additionally, in CCS operations, production of CO_2, or carbonic acid due to the presence of formation water, is not anticipated. The net impact of these two conditions means that the service conditions for CCS injection wells, from a corrosion viewpoint, are expected to be much less severe than those of corresponding EOR wells. Even if the decision is made to transport and inject wet CO_2, the experience and technology developed for CO_2 EOR provide~~s~~ valuable lessons learned that can be applied directly to the design of all CCS injection wells.

As a result of the challenges associated with managing produced water in an EOR project, most fields that convert from conventional water flooding operations to CO_2 based EOR undergo significant retrofitting and modification of surface facilities and wellbore equipment (both injection and production). This results in substantial costs prior to commencement of the CO_2 EOR project. Once CO_2 injection begins, it can take several years before a response (increased production) is observed. Field experience has demonstrated that, over the life of an EOR project, incremental production of between 8%–20% of the original oil in place might be expected with net requirements of 5 to 12 thousand cubic feet of CO_2 for each barrel of oil produced. These points illustrate the challenging economic conditions faced in CO_2 EOR projects.

3. Well Design for CO_2 EOR

All wells have two basic elements: the wellbore, which includes the casing, cement, and casing heads, and the completion which includes the packer, tubing, and wellhead valves assembly. These are also the components that must survive exposure to injected and produced fluids to ensure the long term safety and integrity of the planned operations. Industry has developed many standards for well equipment design that are routinely used in CO_2 EOR operations today (table 2). For reference, typical injection and production wellbore designs are presented in figure 1.

3.1. Casing and Tubing

As is required in all engineering designs, surface equipment and well components are designed for the anticipated operating pressures. This constraint translates into selecting the appropriate casing and tubing grade and weight/thickness to avoid wellbore collapse.

Economically, it is preferable to use carbon steel components, as opposed to exotic alloys or clad materials for well construction, whenever possible. However, in CO_2 EOR applications, due to the combined presence of CO_2 and water, carbon steel (subject to direct exposure to injected or produced fluids) must be either coated or lined with appropriate materials to prevent corrosion. Materials meeting these constraints are presented in table 1. As shown, tubing strings exposed to wet CO_2 typically have a coating of plastic, epoxy, or glass reinforced epoxy as a protective liner.

In very specialized cases, where significant concentrations of hydrogen sulfide are present (combination of concentration, pressure, and temperature), special grades of carbon steel or, in severe cases, corrosion resistant alloys (CRA) may be required. However, these applications are more typical of deep (>15,000 feet) disposal wells rather than CO_2 EOR injection wells.

In CO_2 EOR operations, it has been observed that production wells, because they produce multiphase fluids (oil, water, gas), are somewhat less susceptible to corrosion than injection wells. One can think of this as a dilution or coating effect induced by the hydrocarbon mixture. Nonetheless, corrosion can occur. To suppress corrosion, inhibition chemicals, either in batch or continuous treatment, are used on a routine basis.

3.2. Cement

Cementing is critical to the sound mechanical performance of a well. The cement anchors the casing to the formation providing structural stability and providing a seal between the casing and the surrounding formation. The vast majority of wells in CO_2 EOR service are cemented with standard Portland cements. While the chemical degradation of Portland cement by carbonic acid is well known, field experience strongly suggests that the dynamics of this process may not necessarily be as problematic as laboratory data suggests should be the case.

Solutions to limiting the cement degradation caused by carbonic acid have been developed for use in severe service situations. These solutions usually involve the addition of materials like fly ash, silica flour, or other acid resistant materials, which reduce the proportion of Portland cement in the total mixture. These specialty cements have not been widely used in CO_2 EOR applications, mostly due to their higher costs and the observed adequate performance of standard Portland type oil well cements.

3.3. Corrosion Control

The carbon steel casing used in CO_2 EOR wells can be subject to corrosion when exposed to wet CO_2 and/or associated formation fluids if not properly protected or if those protection measures fail (figure 2). Available protection measures include:

- Correct placement of cement
    - Careful hole cleaning and mud removal prior to placement of cement
    - Use of casing centralizers
    - Use of adequate volumes of cement
- Use of acid resistant cements under severe conditions
- Cathodic protection of the casing
- Use of biocides and corrosion inhibitor chemicals in the annular fluids

3.4. Completion Equipment

As previously discussed, use of the WAG injection process in CO_2 EOR operations, creates a worst case scenario from a corrosion and materials stand point. The components of a well that are routinely exposed to these conditions include wellheads, tubing strings, and packers. These components are commonly considered the completion equipment in the well.

To control corrosion, wellhead valve trims and wetted parts of packers are typically stainless steel, nickel, or Monel. Tubing, although made of carbon steel to minimize cost, is coated with an internal plastic or epoxy resin or a glass reinforced epoxy lining as illustrated in figure 3.

Early experiences with injection of supercritical CO_2 demonstrated the need for selection of elastomers and seals resistant to swelling. As a solvent, supercritical CO_2 not only dissolves in crude oil but in any hydrocarbon based material. This effect has led to the use of Teflon and nylon packings and sealing elements, as well as hardened rubber (80 -90 durometer Buna-N) for packer elements.

Conclusions

- Industry experiences, procedures, and technologies developed over the past 35 years of commercial scale injection of CO_2 for EOR provide a substantial basis for technical standards and practices for use in the design, construction, and operation of wells used for CCS.
- The WAG injection process used in CO_2 EOR production operations represents a worst case exposure situation for wells and related surface equipment, due to the long term exposure of these components to CO_2 acidified water solutions. Assuming that CCS CO_2 is transported in a dry state, as currently done in CO_2 EOR practice, then surface piping and injection wells in CCS applications will be exposed to a much more benign corrosion environment.
- When appropriate mitigation measures are applied, normal carbon steel can be safely and effectively used for well casing and tubing. Service lives of 20-25 years or more, comparable to other oil and gas wells, can be expected. Use of corrosion resistant alloy tubulars may only be necessary under special situations.
- In general, conventional Portland type oil well cements provide sound performance in most CO_2 exposure situations. Acid resistant cements are available, but have only been used selectively in CO_2 EOR applications.
- Due to the solvent characteristics of supercritical CO_2, special attention must be paid to rubber and plastic components such as packing and sealing elements. Use of Teflon, nylon, and hardened rubber (80-90 durometer Buna N) is recommended where appropriate.
- Valve trim, wellhead equipment, and other relatively small surfaces exposed to injected or produced fluids should be made of stainless steel, nickel, or Monel depending on the specific conditions of exposure.
- Tubing that can be potentially exposed to a wet CO_2 stream should be plastic coated or have glass reinforced epoxy liners. Use of corrosion barrier rings in tubing connections is also recommended.
- Other downhole equipment (landing nipples, subsurface valves, and packer internals) exposed to injected or produced fluids should be nickel plated or constructed of stainless steel as appropriate.

References

1. American Petroleum Institute, 2007, Background Report, *"Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology"*, 1220 L Street NW, Washington, DC.

Tables and Figures

Table 1 Materials of Construction for CO_2 Injection Wells

Component	Materials
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 Nippl e	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

Table 2 API Specifications and Recommended Practices for Well and Field Piping

API Reference	Title
Spec 5/CT ISO 11960	*Specifications for Casing and Tubing*
Bull 5C2	*Performance Properties of Casing Tubing and Drill Pipe*
Spec 5L	*Specification for Line Pipe*
Spec 5LD	*Specification for CRA or Lined Steel Pipe*
Spec 6A	*Specifications for Wellhead and Christmas Tree Equipment*
Spec 6D/ISO 14313	*Specifications for Pipeline Valves*
Bull 6J	*Testing of Oilfield Elastomers*
RP 10B -2 through 5	*Testing Well Cements*
Spec 10A/ISO 10426 -1	*Specifications for Cements and Materials for Well Cementing*
TR 10TR1	*Cement Sheath Evaluation*
RP65 Part 1	*Cementing Shallow Water Flows in Deep Water Wells*
Spec 11D1/ISO 14310	*Petroleum and Natural Gas Industries – Downhole Equipment – Packers and Bridge Plugs*
Spec 15HR	*High Pressure Fiberglass Line Pipe*
Spec 15LR	*Low Pressure Fiberglass Line Pipe*
RP 15TL4	*Care and Use of Fiberglass Tubulars*
RP 90	*Annular Casing Pressure Management for Offshore Wells*

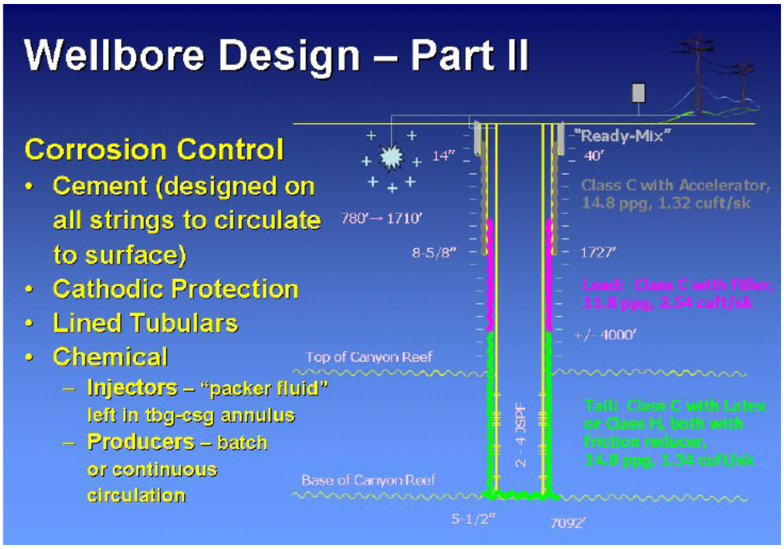

Figure 1 Typical EOR Wellbore Design

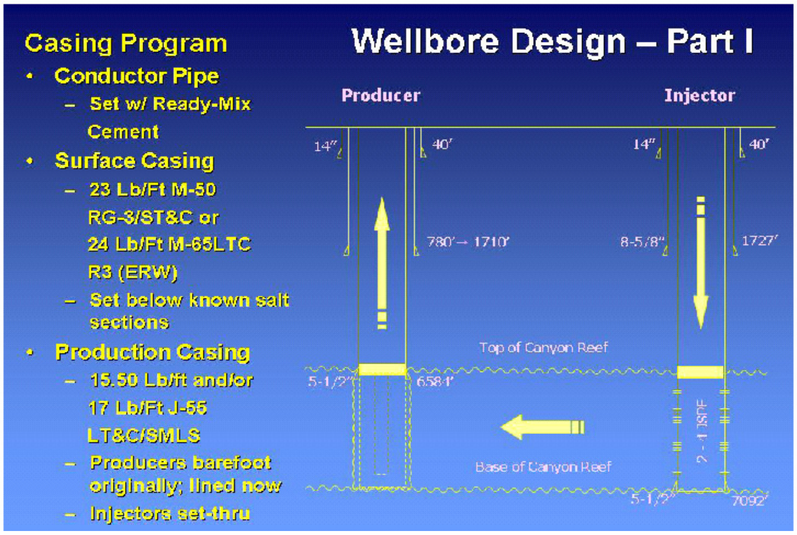

Figure 2 Typical EOR Wellbore Corrosion Control

Figure 3 Glass Reinforced Epoxy Lined Tubing (GRE)

All Tables and Figures from Reference 1.