

Enabling Carbon Steel with a Special dense CO₂ Corrosion Inhibitor – A Field Study

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ABSTRACT

The asset integrity of a dense phase, super critical CO₂ (scCO₂) production system is critical to efficient, safe, cost effective operation. Until recently these assets were managed using carbon steel lined with a thick, presumably resilient polymer. However, these polymer lined pipes pose a significant problem in terms of cracking. Corrosion behind the liner was causing a hydrogen cracking issue that was difficult to mitigate. Introduction of a specially designed scCO₂ corrosion inhibitor has shown that bare carbon steel can be protected against corrosion in these harsh conditions. This new method of asset management enables more efficient, less costly, and safer operation for the operator. This paper shows data from a field trial strongly supporting the advantageous use of this new technology.

Key words: supercritical CO₂, corrosion inhibition, mild steel, field trial, low capital cost

INTRODUCTION

In recent years the oil and gas industry has made significant commitments to carbon reduction.¹ Aligned with the goal of decreasing carbon emissions the authors have developed a corrosion inhibitor (CI-1) that is intended to protect scCO₂ systems that are wet or water contaminated (1000 ppm).² The development and composition of this corrosion inhibitor (CI) for dry scCO₂ is reported elsewhere.^{2,3} While chemical companies have been treating high water cut, production enhanced, CO₂ floods (i.e. enhanced oil recovery [EOR]) for several decades there were no inhibitors designed specifically for CO₂ disposal systems or wet scCO₂ systems producing CO₂ for sale.⁴

During the development of CI-1 several key criteria were specified for a CI applied in a mostly dry system expected to have ~1000 ppm water. Namely this CI needed to be highly soluble in scCO₂ so it could be injected into the dry gas and be transported to areas of the system where water might accumulate. If the

inhibitor was insoluble in scCO₂, it could precipitate near the injection point and cause gunking. Through the development of CI-1 it was determined that many CIs commonly used for EOR were insoluble in scCO₂ and therefore unable to transport seamlessly to the point of need. CI-1 was found to meet this criterion. In addition it was determined that commonly used amines which work in natural gas applications were susceptible to salt formation in scCO₂ systems if the pressure was to drop into gaseous conditions.

CI-1 is currently being applied to a critical CO₂ disposal operation in Australia. This product has been in use since mid-2019. Compliance reports indicate continuous injection since the start of application. The customer performs regular ultrasonic thickness scanning and inline inspection pigging on intervals from 6 to 24 months. The customer also has live data at critical locations from electrical resistance, Permasense⁽¹⁾, and gPIMS⁽¹⁾ probes. To date, all data show no signs of corrosion in this system.

This paper describes a much different system of application where CI-1 was recently field trialed. The new system is designed for scCO₂ which is produced for sale as an EOR gas or other commercial uses. A diagram of this system is shown in Figure 1.

The wells pipelines (12") and well header pipeline (16") are fabricated from UNS⁽²⁾ S31603 (316L stainless steel) and the specification break in Figure 1 shows the transition point from 16" 316L to a 16" UNS K03014 (API⁽³⁾ 5LX65 carbon steel) pipe with a high density polyethylene (HDPE) liner. As shown in Figure 2, the 16" X65 line has a wall thickness ranging 0.312" (7.92 mm) to 3.75" (9.52 mm) and the HDPE liner has a wall thickness of 0.5" (12.7 mm). The customer was looking for a better alternative to the HDPE lined carbon steel because this material is susceptible to sulfide stress cracking due to the migration of small amounts of H₂S, water, and CO₂ behind the liner at the girth welds. Failure of a scCO₂ line can create significant hazards. Studies in the United Kingdom in 2015 and 2019 showed the massive impact of ruptures of 2" (50.8 mm) and 8" (203.2 mm) pipelines.^{5,6}

The production from the three wells is shown in Table 1. The system produces 204 bbl of water per day (BWPD) from wells 1 and 2 as well as 105 BWPD from Well 3. This amount of water is significantly more than the 1000 ppm expected in the initial application of CI-1, which is why this field trial was closely monitored. Well 3 was shut in early in the trial (8 July 2021) to better manage the CI dosage since less produced water allowed the maximum chemical pump range to be utilized.

Table 2 shows the brine composition and Table 3 shows the gas composition for wells 1 and 2. The brine is a very low total dissolved solids (TDS). The most remarkable feature of the brine is the incredibly high iron content seen in Well 2. The gas analysis is no less surprising. Most oil and gas wells do not contain oxygen due to its reactivity and the long residence times of oil and gas reservoirs. However, these wells contain 100.4 and 99.5 ppmv of oxygen in the gas stream. Equation of state modeling⁽⁴⁾ (MSE-SRK) using the parameters in Tables 1 through 3 indicates that all of the iron is bound in water soluble complexes and there could be 314 and 288 ppb of oxygen in the aqueous phase of Well 1 and Well 2, respectively. This amount of oxygen could be extremely detrimental to corrosion and cracking. A longer study will need to be conducted to determine if CI-1 can mitigate the effects of oxygen in this system.

⁽¹⁾ Trade name

⁽²⁾ Unified Numbering System for Metals and Alloys (UNS). UNS numbers are listed in Metals & Alloys in the Unified Numbering System, 10th ed. (Warrendale, PA: SAE International and West Conshohocken, PA: ASTM International, 2004)

⁽³⁾ American Petroleum Institute, 1220 L Street, Washington, DC 20005

⁽⁴⁾ Modeling was performed with OLI StreamAnalyzer 10.0.2.1. StreamAnalyzer is a trade name of OLI systems.

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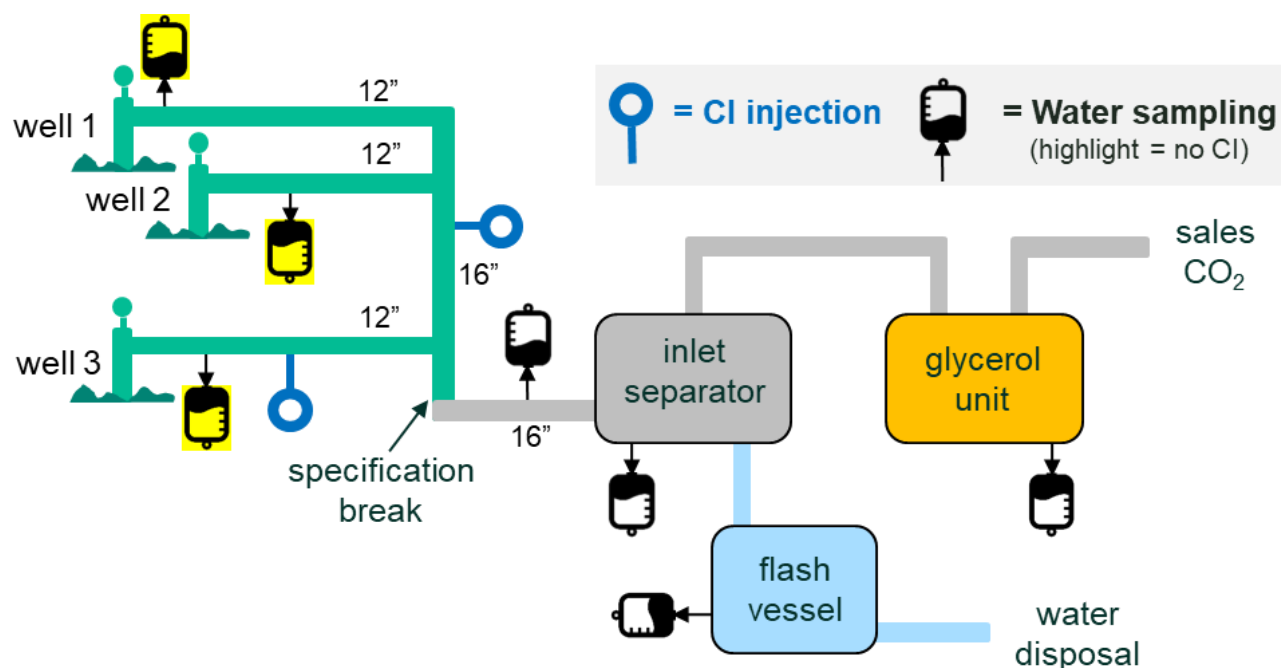


Figure 1: Schematic of CO₂ production system. Blue circles show chemical injection locations. Black syringes show water sampling locations. Highlighted syringes show sampling locations with no CI injection upstream. All well lines are 12" diameter stainless steel and the wells' header is 16" diameter stainless steel (green). Everything downstream of the spec. break was carbon steel with a HDPE liner before CI application.



Figure 2: Photo of 16" pipe section typical of polymer lined carbon steel after spec. break. The pipe has a wall thickness ranging 0.312" (7.92 mm) to 3.75" (9.52 mm). The HDPE liner has a wall thickness of approximately 0.5" (12.7 mm).