METALLURGIC AND COATING SOLUTIONS FOR CORROSION MITIGATION IN ANNULAR FLOW WELLS

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INTRODUCTION

Continued extension of lateral lengths in overpressure wells has created subsequent challenge for the continued production of those wells at maximum economic output. While unconventional wells are known to decline quickly, extended lateral unconventional wells maintain sufficiently high production rates over a longer period that production hydraulic considerations are important factors in initial artificial lift installation. Traditional, tubing flow gas lift can present hydraulic constraints to high-rate wells that can no longer sustain flow up their production casing. Annular flow gas lift presents an intermediate gas lift option that can re-establish production on a well that cannot produce via its production casing but would be constrained by installation of and conversion to flow via a tubing string.

Implementation of annular flow gas lift systems has presented unforeseen challenges. Specifically, the combination of high pressure, high rates, and high temperatures in relatively new production wells has resulted in a significant increase in accelerated corrosive attack of the tubing string. Field investigation and analysis of the fluid environment has indicated the presence of low concentrations of oxygen dissolved in the produced water. Corrosion morphology from failed tubulars further supports the presence of oxygen accelerated corrosion in the form of pitting corrosion as the primary cause of failure of injection gas tubing strings in annular flow wells.

Premature failure of annular flow tubing strings by accelerated oxygen corrosion can result in unnecessary early life well interventions and costly workovers. Common methods to combat downhole corrosion focus on application of chemical inhibitors. However, application via slipstream does not allow for total tubing string protection and shear rate limits of these chemicals can result in incomplete coating of tubing surfaces, even if applied via capillary tubing. Alloyed tubulars or spray metal coated low allow tubulars present an alternative to commonly employed low allow carbon steel tubing, like L80, that are shown in laboratory testing to offer significant corrosion resistance to the flow environment in high rate, annular flow wells.

CORROSION METHOD IDENTIFICATION

Initial identification of corrosion modes can often come from field-based observation of corrosion morphology. Specifically, the presence and pattern of pits observed on tubulars during workover and conversion of annular flow wells noted higher than typically observed incidence of tubing failure during scanning. Joints discarded because of failed tubing scan were visually inspected for proximal cause. While wall loss occurred, the presence of pitting over entire joints of tubulars suggested a more aggressive style of attack was occurring in annular flow wells.

Figure 1 – Corrosion morphology in annular flow wells from Bone Spring and Wolfcamp formations in the Delaware Basin

Many corrosion mechanisms can create pits including CO2 pitting corrosion, H2S pitting, microbial corrosion, and Oxygen pitting corrosion, among others. The presence of the same morphology across multiple formations on low alloy steels in the same flow environment suggested a common cause. Investigation of potential pitting sources across these wells eliminated the majority of the commonly understood causes of pitting in oil wells. The potential presence of dissolved oxygen in the produced water of these wells was the common cause of this corrosion mechanism through elimination of other causes that were not common to all wells and formations.

Oxygen contamination of produced water can occur from a variety of sources. In higher rate, long lateral wells, the quantity of frac water utilized for completions and its long-term unloading through the well offers the most likely source of oxygen contaminated water at this point in the wells life. Increased utilization of produced water for hydraulic fracturing via water recycling creates multiple exposures of that water to air and oxygen containing chemicals. Salt water exposed to atmospheric pressure in a frac pit, for example, can absorb between 8 and 10 parts per million (PPM) oxygen. Removal of this contaminant from the water is very challenging with few known chemistries that can scavenge dissolved oxygen at scale in high flow rate environments (like those experienced during hydraulic fracturing). As a result, produced water with dissolved oxygen is introduced to long lateral wells during hydraulic fracturing. Differential perforation unloading over time results in extended wellbore exposure to oxygen contaminated water, and low alloy steels utilized for annular flow gas lift would be exposed to dissolved oxygen from this extended frac load recovery.

OXYGEN SENSING AND LOW ALLOW STEEL CORROSION

Oxygen pitting corrosion is the most likely cause of the significant tubing failures identified through tubing scans in annular flow wells via observed corrosion morphology. To confirm oxygen pitting, though, in line flow measurement of dissolved oxygen in water was necessary. Dissolved oxygen flow sensors were installed in wells with known pitting corrosion to measure the dissolved oxygen in the produced water. Using this flow cell, oxygen levels up to 50 PPM were detected in the flow stream of an annular flow well.

With oxygen present, additional factors contribute to creating an environment conducive to accelerated oxygen pitting corrosion. Temperature and pressure are key variables in creating an accelerated, pitting based corrosion mode in low allow steels.

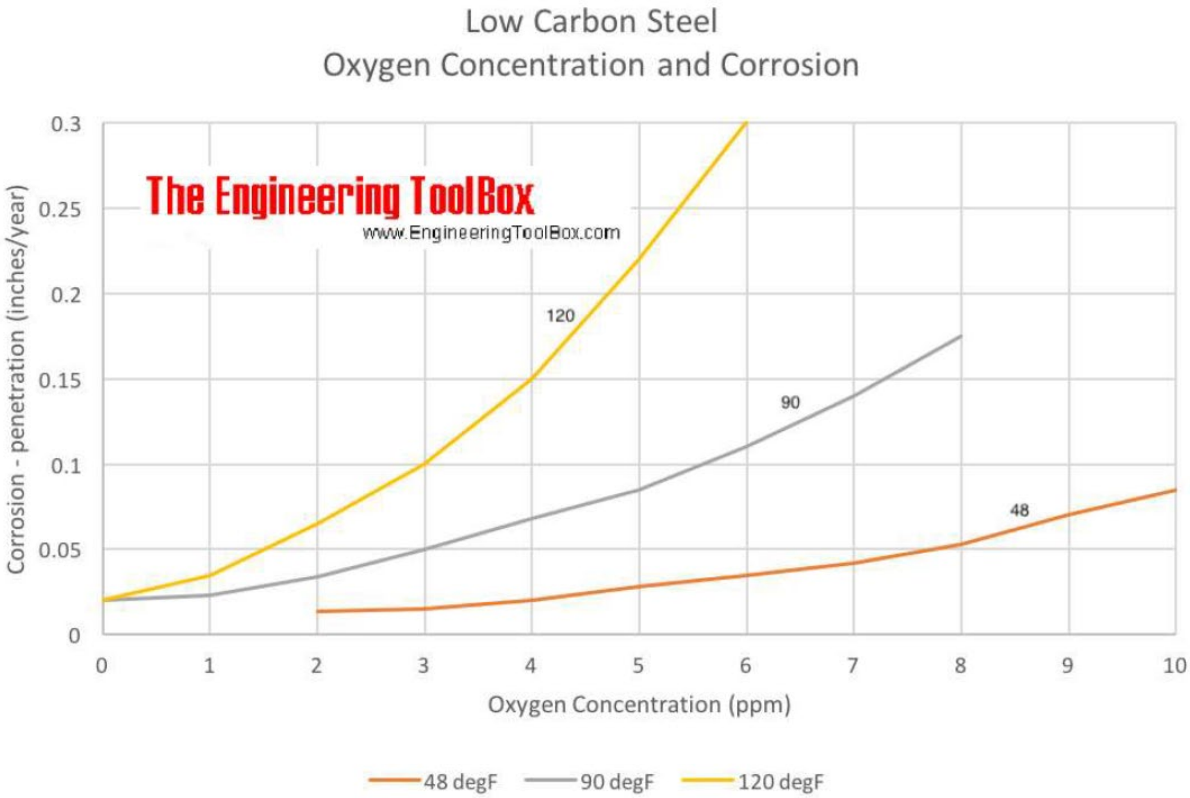

Figure 2 – Oxygen corrosion rate at varying temperatures.

Figure 2 describes the relationship between oxygen-based corrosion of low carbon steels (like L80 grade tubing). Oxygen corrosion rate increases with both temperature and corrosion, though the relative impact of elevated temperature is more pronounced. General trends observed from field-based scans of tubing removed from annular flow wells shows that the pitting and overall corrosion environment is most prevalent in the deeper sections of the tubing string where the flow is hotter, often well in excess of 120°F by downhole gauge observation.

Hydrostatic pressure presents an additional factor that both accelerates oxygen pitting corrosion in low alloy steels and creates a preferential environment for pitting based corrosion vice general corrosion. Work by Su et al. described this effect in controlled experimentation designed to mimic corrosive behaviors observed in deep sea applications. The morphology observed in their experimentation mimics the behavior observed in annular flow wells with oxygen dissolved in the produced water.

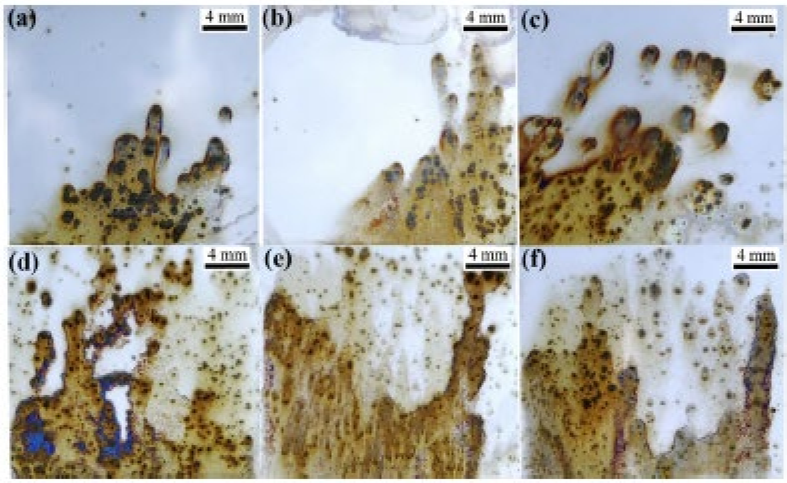

Figure 3 – Oxygen pitting corrosion morphology observed by Su et al. after 6 hour immersion in 3.5% by weight NaCl solution.

Su et al. discuss the relationship between corrosion rate by both the anodic and cathodic corrosion of steel. In their experimentation, pressure in a brine environment inhibited the anodic corrosion reaction of low alloy steel (commonly, rust). However, the presence of dissolved oxygen in the same system increased the rate of the cathodic corrosion of steel, electrochemically coupling the bulk surface of the tubing with another portion of tubing in the presence of oxygen. These cathodic reaction result in preferential corrosion of a singular site, creating a pit. Their team further investigation the chemical content of the corrosion sites via Energy Disperse Spectroscopy (EDS), finding that the alloying compounds of carbon steel acted as the initiation points for the pits observed in the experiment. They attribute this local cathodic cell to the chemical inhomogeneity of the alloying compounds within the bulk iron substrate.

Fan et al. also reviewed the corrosion potential of metal screens in deep gas floods due to downhole failures observed in their field. Their results similarly showed that the presence of oxygen and, more specifically, its concentration, drove the overall cathodic corrosion reaction in their steel bottom hole assemblies. Similar to Su et al., they found that the presence of oxygen in a high pressure well increased the overall corrosion rate of steel by its cathodic corrosion reaction, causing rapid deterioration and failure of downhole equipment.

Beyond these published examples, further testing using the chemistry and shear rates of typical annular flows wells was conducted as part of inhibitor testing. Specifically, field fluids in a 80/20 water to oil ratio were heated to 150°F in a laboratory setting. Expected partial pressures of CO2 were applied to the test cell (~2.5 PSI) to mimic carbonic acid formation commonly seen in low CO2 partial pressure environments. Finally, oxygen was introduced to the flow cell with flow cell testing of L80 samples conducted at 320 Pascals. Control cells from this testing exhibited corrosion morphology consistent with field-based observations from annular flow wells.

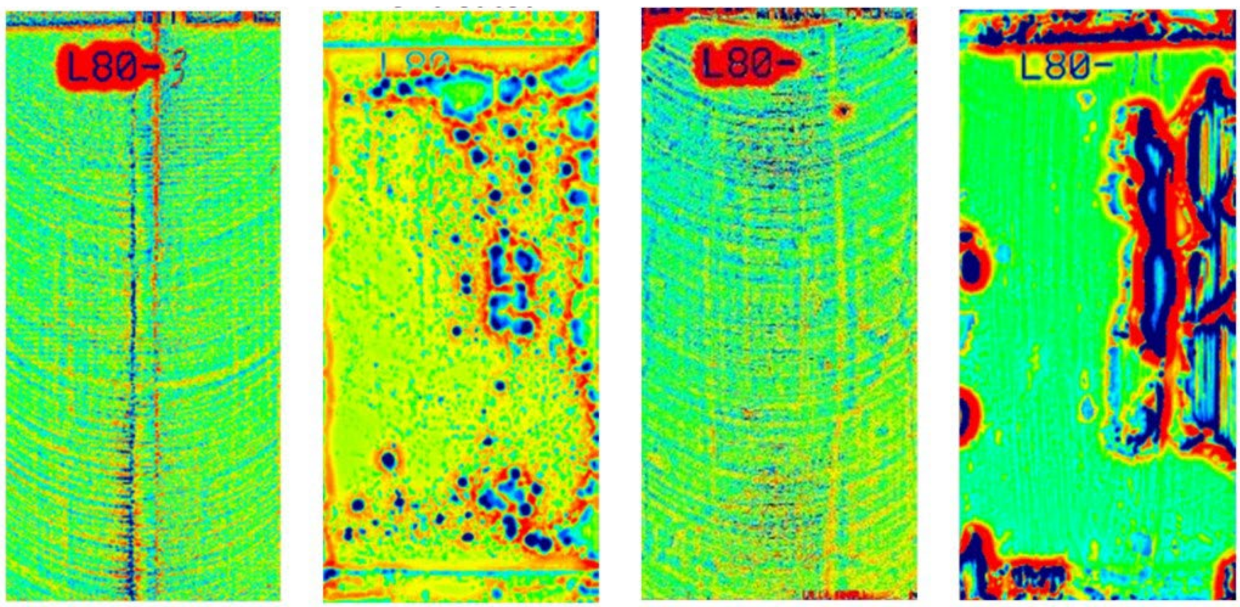

Figure 4 – L80 corrosion sample results exhibiting pitting morphology during 14-day flow cell testing in an autoclave. The left samples were control. The right samples were in the presence of corrosion inhibitor chemical, one passed (left) and one failed (right).

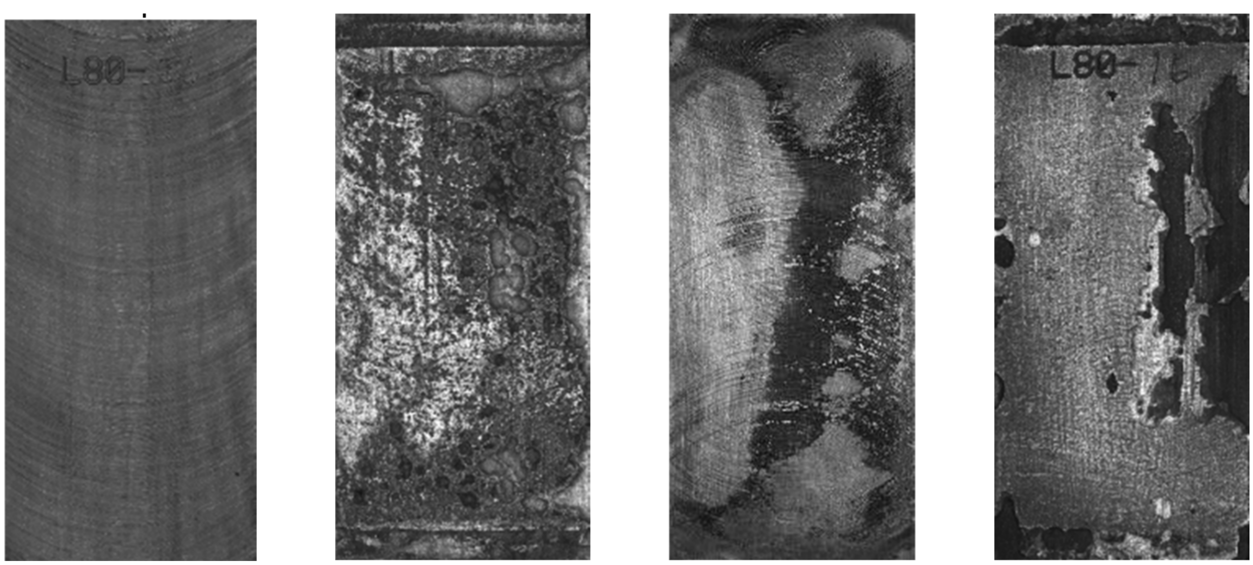

Figure 5 – Photographs of the same L80 samples showing corrosion morphology.

CORROSION MITIGATION OPTIONS AND TESTING

Two common options to limit corrosion in wells are the application of corrosion inhibitor chemical and the use of corrosion resistance alloys. As alluded above, corrosion inhibitor selection should be tailored to the specific well chemistry and corrosion mode. Further, corrosion inhibitors must contact the exposed surface to function. Contact occurs if the chemical is present and shear rates are within tolerance for the chemical to coat the metallic surface exposed to the corrosive environment. In annular flow wells, this presents additional design challenges. Production rates in high rate wells, particularly in smaller inner diameter casing strings with 2 7/8” production tubing installation, can be too high for common corrosion inhibitors to successfully adhere to the metallic surface. Additionally, as production rates decline, application of chemical via slip stream limits the portion of the tubing string exposed to corrosion inhibitor chemicals to the depths at and above the injection point. This corrosion mechanism is accelerated by higher pressures and temperatures in the presence of oxygen, conditions present deeper in a high rate, annular flow well. Trends in field tubing scans support this concept, and the cost of application and challenges with identifying a chemical capable of inhibiting this corrosive environment open the potential for corrosion resistant alloys as a solution.

Using a similar testing method, 3 different corrosive resistant tubing strings were tested in the same flow cell described previously. L80 with 1% Chromium, P110, and standard L80 coated with a spray metal coating containing chromium were all tested against an L80 control sample in a high shear, high temperature flow cell with oxygen dissolved in the water. Overall, a direct comparison of the L80 control to 1% chromium and P110 samples showed significant improvement in resistance to pitting corrosion. P110 offered the greatest resistance to the identified corrosion mode under conditions like high rate, annular flow wells. 1% chromium L80 showed improvement compared to L80 in the laboratory setting.

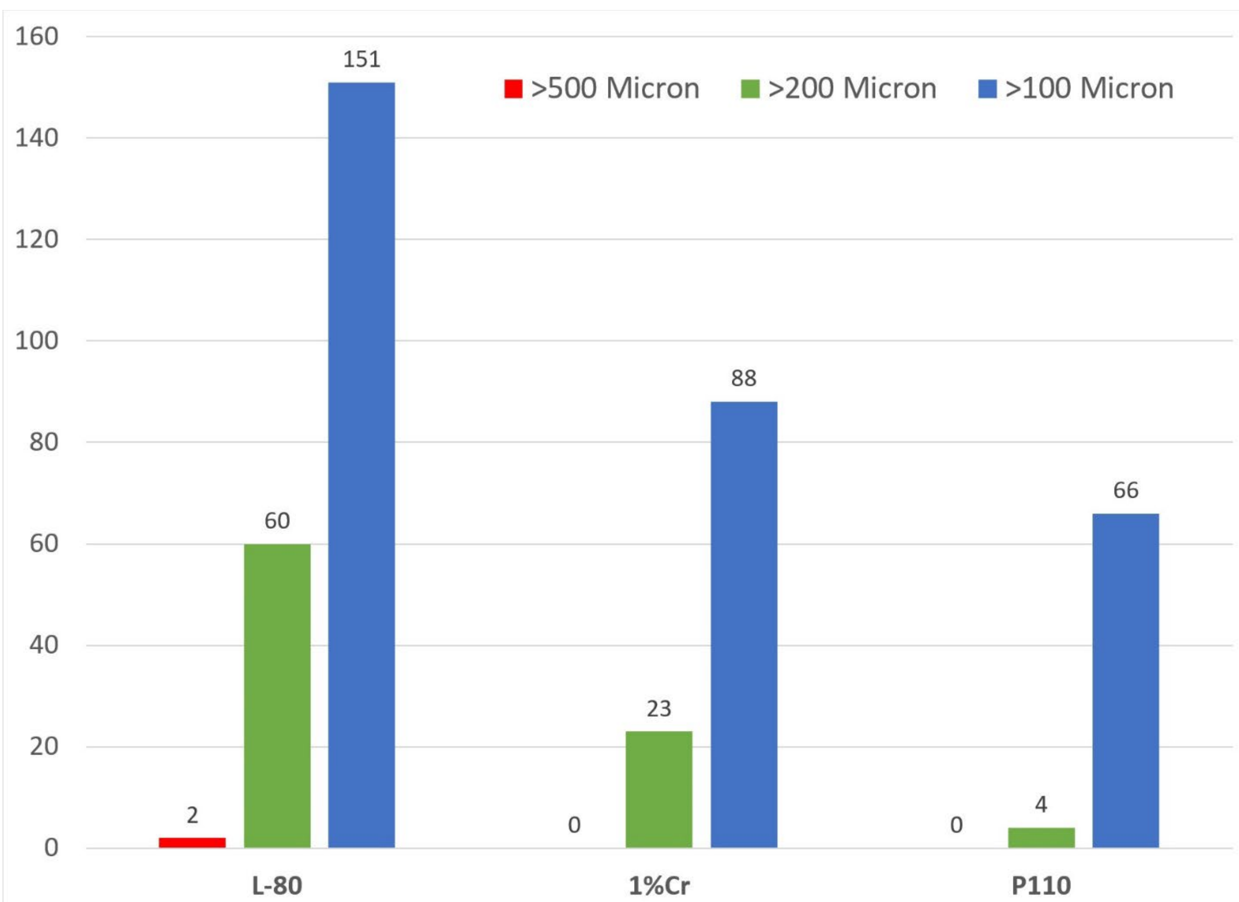

Table 1 – Autoclave test results for different metallurgy showing pit count as a measure of corrosion resistance.

The spray metal coating was tested in the same autoclave solution, but the application of the coating prevented a side-by-side test to the tubing metallurgy coupons. Specifically, a rectangular coupon could not be coated with the coating equipment. As such, a circular sample was extracted from a coated 2 7/8” L80 pup joint and installed in the autoclave.

Figure 6 – Autoclave testing of a spray metal coating applied to 2 7/8” L80 tubing.

Results from the autoclave testing showed no incidence of pitting corrosion to the test sample. As such, a weight comparison of the sample before and after the autoclave test was the best measure of corrosion rate available. Those results effectively showed no corrosion to the sample during the autoclave test.

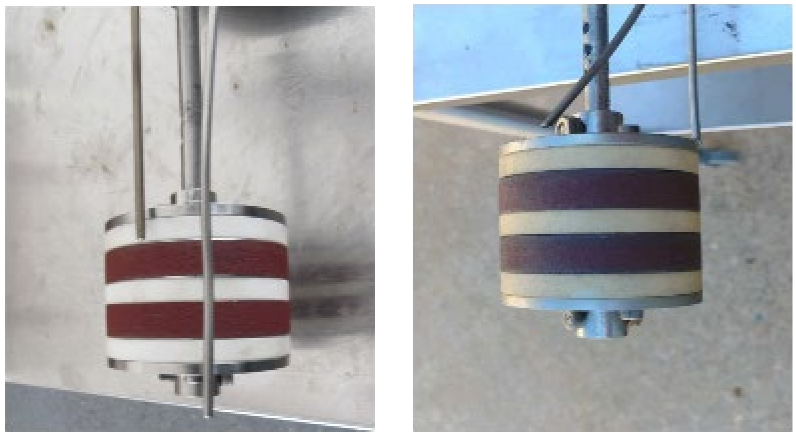

Figure 7 – Spray metal autoclave test results. Pretest (left) and posttest (right)

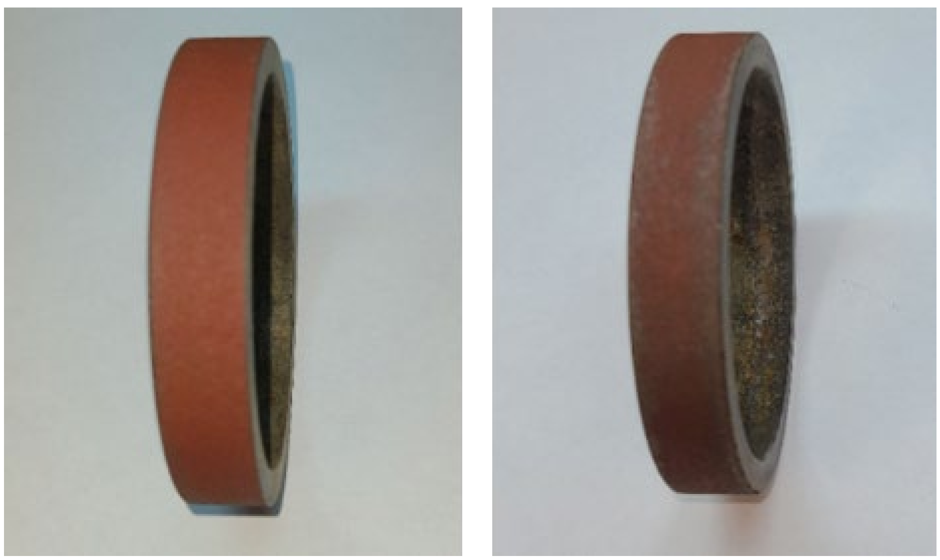

Figure 8 – Spray metal autoclave test results. Pretest (left) and posttest (right)

Sample #	**Alloy**	**Surface Area (cm2)**	**Density (g/cm3)**	**Weight Before Test (g)**	**Weight After Test (g)**	**Weight Loss (mg)**	**Corrosion Rate (mpy)**	**Average Corrosion Rate (mpy)**
Ring 1	L80-0Cr	29.28	7.87	114.1790	114.1171	61.90	1.84	**3.68**
Ring 2	L80-0Cr	29.15	7.87	113.8845	113.6996	184.90	5.52	

Table 2 – Spray metal sample test results

CONCLUSION

Annular flow gas lift is a valuable transition lift method to sustain production rates on longer lateral wells that are no longer capable of flowing up casing. However, dissolved oxygen in the produced water of these wells, most likely from frac water, has created an aggressive corrosion environment for L80 tubing installations. The high rate and pressures of an annular flow well are a challenging environment for application of corrosion inhibiting chemical. Corrosion resistant alloys and spray metal coating offer an alternative to chemical treatment that exhibit improved corrosion performance in laboratory flow cell testing. Ongoing field trials will provide validation of these laboratory results.

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