FIELD TRIAL DATA DEMONSTRATES BENEFITS OF METALLIC COATING THAT ACTIVELY PROTECTS ROD STRINGS AGAINST CORROSION IN CHALLENGING WELL ENVIRONMENTS

Alex Perri, ChampionX Artificial Lift
Angela Sultanian, Pro-Rod Coiled Rod Solutions

ABSTRACT

The objective of this paper is to share insights on mitigating sucker rod corrosion damage in vertical, horizontal, and deviated wells with aggressive corrosive conditions such as H_2S and CO_2, particularly those with histories of corrosion-related rod and tubing failures.

Corrosion is a common problem in production operations, accounting for two-thirds of all rod string failures and costing hundreds of millions annually to remediate downhole tubing damage alone, according to NACE International[1, 2]. This paper presents the development and initial field application results of a continuously applied metallic coating that actively participates in the electrochemical aspects of corrosion in carbon and low-alloy steels. Moreover, the solution protects uncoated segments of rod and other steel components in the wellbore while reducing abrasion by enhancing friction properties compared to bare steel.

The authors outline the key properties and characteristics of this coating, including evaluating its performance relative to traditional corrosion protection measures such as barrier coatings. Rather than acting as a barrier layer, the metallic coating actively protects against corrosion and has inherent chemical properties that self-heal surface scratches and abrasions. This is particularly valuable in horizontal and directional wells with high dog leg severities and sideloading forces that contribute to rod/tubing abrasion.

Results are presented from laboratory testing as well as initial trial applications in wells with histories of rod failures due to corrosion, typically requiring interventions with workover rigs. In one such trial, the metallic coating was applied to a coiled rod string installed in a high-CO_2 content well on progressing cavity pump. The coated coiled rod string was installed in January 2019. After five months of service, the coated string was pulled to inspect its condition. The examination revealed that the rod was unaffected by corrosion. A second inspection after nine months found evidence of rod string wear but no corrosion damage. The well has been in operation for 140 weeks (and counting), achieving a ten-fold improvement in the average run time before installing coated coiled rod.

The novelty of this approach is the application of an advanced materials science-based coating to extend rod string service life in corrosive environments through active protection. In addition, it requires no special handling or installation equipment, and the metallic material allows rod strings to be recycled (eliminating potential environmental and downstream damage risks associated with barrier coatings).

As supported by lab and field case study data, the results of deploying this method include increased production uptime, reduced workover frequencies and associated remediation costs, and lower overall LOE and lifting cost per barrel of oil produced.

INTRODUCTION

A sucker rod is a solid length of round steel rod with flared and threaded ends for connection. Although varied lengths exist, the standard individual sucker rod length is 25 ft. Rods are coupled together to span the depth of a well and connect the surface driving unit to the preferred downhole pump, which can be either reciprocating (rod pump) or rotary, such as a progressing cavity pump (PCP) (Figure 1). The wellbore is often deviated and may also be oriented directionally/horizontally. The sucker rod string can drag against the inside of the tubing in areas of deviations or directional variations, and must do so whilst exposed to reservoir fluids.

Coiled or continuous sucker rod is a single, very long sucker rod with only two connections: at the polished rod and at the downhole pump. In the absence of couplings (Figure 2), the coiled product conforms to the curvature of the tubing and provides a specialized solution to the challenging production demands posed by deviated and directional wells. In oil and gas production, the rod string is considered a consumable, and low-cost materials are often the most economical option. These materials have historically included plain carbon and low-alloy steels containing less than 5% alloying elements such as chromium and nickel.

Corrosion is one of the leading factors in artificial lift system failures, particularly with sucker rods. Operating conditions and wellbore geometry complicate common corrosion prevention methods. Presented here is a new metallic coating that actively protects the rod string against corrosion and has intrinsic physical properties that self-heal surface scratches and abrasions.

CORROSION

Metallic corrosion is the deterioration of a metal as a result of a reaction with a particular fluid environment. The metal loses electrons and “oxidizes.” Corrosion can also occur when more than one dissimilar metal is coupled within the same conductive (electrolytic) fluid. A current flows between them because of the inherent potential difference between the materials. One material will behave in a more noble manner (the cathode) and will oxidize the less noble (the anode) material (Figure 3). That is, electrons will be sacrificed by the anodic material in preference to the cathode, resulting in corrosion or oxidation of the anode (Figure 4).

CORROSION PREVENTION

The nature of rod-driven production and particular wellbore dynamics must be understood when considering corrosion prevention measures. Certain methods of corrosion mitigation cannot tolerate surface damage. A horizontal/deviated well has more rod-tubing contact and introduces higher sideloads to the rod string. Workover or service activities specific to coiled rod applications include high-force clamping with metallic devices and conveyance through the injector/guide system (Figure 5). The clamping pressure required for rod string installation or removal increases proportionally with the depth of the well, applying a concentrated compressive force on the outer surface of the rod.

Although a comprehensive discussion of methods to mitigate corrosion damage is beyond the scope of this paper, common approaches specific to sucker rod application are introduced, along with brief explanations of their limitations. In general, approaches to mitigate corrosion are either environmental or material-based. Some systems modify or neutralize the environment of exposure, such as pre-treatment of injection fluids. This approach is considered uneconomical for large-volume pumping operations. Similarly, chemical-based corrosion inhibiting solutions also have limitations. These products introduce highly sophisticated thin films to the downhole components. Two common delivery methods for inhibitor application are batch and continuous. As noted, deviated wellbores result in repeated rod-tubing contact, which can disrupt the thin film layer and expose the metal beneath. For this reason, continuous application is superior to a batch-style inhibitor since it supplies a constant stream of inhibition to better protect these high contact areas. Despite its limitations, batch-style inhibition is more economically appealing than continuous application.

A material-based approach to corrosion prevention includes substituting a corrosion-resistant alloy (CRA) with recognized resistance to the environment. These costly materials develop a very thin passivated oxide layer to provide corrosion resistance. The tenacity of this layer may be compromised by a change to the environment or operating conditions, such as temperature or wear damage.

More economically, a superficial coating can be applied to impart protection to the component. Three primary categories of coatings include:

- Barrier-style
- Corrosion-resistant metal
- Anodic metal

A barrier style coating can only offer protection if it remains intact and otherwise adhered to the surface of the component. In areas that become damaged, an ingress of corrosive fluid or high operating temperatures may compromise the adhesion and conceal subsurface damage. These thin polymeric coatings can be damaged during handling and are only operational up to a maximum temperature of 200°F. On-site repairs to the coating in the case of rod string damage or changing the pump depth can be costly and time consuming. Eventually, when the rod string has surpassed its serviceable life, disposal must be performed in accordance with regional environmental guidelines and regulations.

Coatings with a more noble corrosion-resistant metal (CRA) are more economical than outright substitution of the entire component with a CRA, but are still quite costly. To date, this approach has not been applied to coiled rod for several reasons other than the cost of the material. The primary reason is that these coatings tend to be intolerant of operational damage. That is, should the base metal become exposed, the noble material-to-base material ratio is unfavorably high, and the corrosive damage would be both concentrated and accelerated electrochemically. Additional reasons include:

- Similar on-site repair challenges to polymeric coatings
- More noble metallic coatings are more rigid, less flexible, harder, and stronger than the base material, and may become chipped or cracked in handling processes and under operating conditions

The third form of coating is an anodic metal, which is the topic of interest in this paper. This new form of corrosion protection for the coiled rod string employs the fundamentals of electrochemistry by introducing an anodic metal coating to the outer surface. The concept of a sacrificial anode is not new; it has been employed in different manifestations in multiple industries. The most compelling argument for using an anodic metal coating is that it provides continuous protection even in areas that become damaged mechanically. There is a distance-based protection imparted by this form of coating, such that areas in which the coating is damaged either by mechanical removal or chemical attack still remain protected. The distance-effect offered by the sacrificial anode also eliminates the need for on-site repair at splice welds. The anodic metal coating was developed to include considerations for flexibility for coiling and uncoiling, enduring clamping pressure inside gripper mechanisms, and tolerance of damage due to wellbore deviations. The physical properties of the coating offer a reduction in dynamic friction that is approximately 25% lower than plain carbon steel. The reduced friction results in less drag during contact with production tubing and better tolerance to abrasive fluids. The metallic nature of the coating permits a much wider range of service temperatures and may be deployed in EOR wells, including steam injection applications. The sacrificial anode coating is well adhered to the base material, is equally flexible, and remarkably ductile, which results in the coating “smearing” rather than fracturing and potentially disbonding from the base material surface.

LAB RESULTS

Corrosion testing

Considerable laboratory corrosion testing has been performed on the anodic coating. Samples of the coating were subjected to NACE TM0185[3] corrosion testing. The autoclave test consists of exposing a length of coated product to three phases of fluids for 30 days. The chloride, H_2S, and CO_2-containing environment and other test conditions are presented in Table 1. After 30 days of exposure, the coating demonstrated excellent adhesion to the base material (Figure 6). The same test was performed with samples containing simulated damage to the coating. The coating demonstrated a lasting protective effect even when removed by 50% of the circumference (Figure 7).

Electrochemical testing using electrical impedance spectrometry (EIS) determined the contrast in electrode potential:

- (-0.3) V for uncoated product
- (-1.3) V for coated product

The analysis was performed using ISO 16773[4] as the reference standard. Electrochemical impedance was measured by applying an AC potential to an electrochemical cell built onto the surface of the rod in the area of interest. The coated product has a lower potential value, and therefore, a decreased propensity for corrosive attack than uncoated base material.

Mechanical testing

The coating has demonstrated a high degree of flexibility (Figure 8). Rotating-bending tests at 500 rpm produced a 22-foot radius of curvature (equivalent to 40% of the ultimate tensile strength of the base material) (Figure 9). The samples exhibited no cracking within the coating or disbondment from the base material after 3 million cycles.

FIELD TRIAL

A candidate PCP-driven well was selected for a full-scale trial. The mean time between failures (MTBF) had historically been 12-14 weeks. Multiple variations of rod products had been used in this well and had been unsuccessful at extending the service life. Repeated rod failures within the deviated depth (650 to 820 ft) were due to aggressive corrosion attack and high stress levels. The fluid environment consisted of 2.3% H_2S and 15.7% CO_2 with the following additional production attributes:

- Wellbore architecture: Horizontal, producing from vertical section
- DLS: up to 11.4°/100 ft
- Tubing: 3.5 in. diameter
- Oil: 12.7° API gravity
- Water cut: 95%
- Pump rating: 660 bbl/d/100 rpm

A rod string nearly 2,625 ft in length was constructed and originally installed. The top 820 ft of the string was uncoated coiled rod, and the bottom 1,800 ft was coiled rod with the metallic coating. Both the coated and uncoated sections used quenched and tempered 1.125-in. diameter AISI 4120M steel rod (Figure 10).

Surpassing the historical MTBF, the rod string was pulled after 22 weeks of service to inspect its condition. Sections of the 820-ft uncoated rod exhibited corrosion damage and wear from tubing contact (Figure 11). The rod diameter was reduced to as low as 1.075 in. At approximately 885-1,150 ft depth (within the coated portion of the string), there was wear damage detected at the tubing collars but no corrosion damage identified even at these worn areas (Figure 12). From 1,150 ft to the bottom of the rod string, there were areas that were becoming polished due to tubing contact, but no significant wear was discovered. The coating appeared polished due to its self-healing properties and it remained well-adhered, even in areas exhibiting wear damage (Figure 13).

After 38 weeks of service, the uncoated section of the rod string suffered a failure at a depth of 12 ft from the surface. The fracture had initiated at an area with considerable corrosion damage (Figure 14). Inspection of the coated rod portion identified no significant damage and only short spans exhibiting wear damage. Samples from a wear-damaged area were removed for microscopic examination. In these areas, 30-40% of the underlying base metal was exposed, and yet no corrosion damage could be identified even microscopically (Figure 15). Additionally, the coating around the remaining 60-70% of the circumference was well-adhered, exhibiting no disbondment from the base material.

The fact that the failure had not occurred at the same historical depth, and no corrosive damage to the exposed base material had occurred, effectively spotlights the overextending protective influence of the anodic coating. It must also be noted that the repeated handling and transference through service equipment of the coated product was not detrimental to the performance of the product. Subsequently, the uncoated 820 ft of AISI 4120M product was removed due to the corrosion damage, and replaced with the same strength of quenched and tempered AISI 4330M product into the string. The rod string was inverted such that the original coated 1,800-ft section was situated in the upper area of the well and the new uncoated 4330M product was in the bottom 820 ft of the well (Figure 16). The rebuilt and inverted rod string was installed again in the same well and continues to operate after 140 weeks of service.

CONCLUSIONS

A sucker rod string faces challenges due to concurrent wellbore geometry complexities, pumping dynamics, and aggressive environments. The coiled rod product can be deployed to improve service in certain circumstances. The superimposing effect of rod/tubing contact with an aggressive environment requires an additional solution. Several methods for mitigating corrosion damage exist, but each has a particular conflict where coiled rod applications are required. The anodic coated base material is an applied principle of advanced materials science used to extend rod string service life in corrosive environments.

The protective effect of the anodic coating concept was verified in preliminary laboratory testing. The full-scale trial has validated the results from laboratory testing from a corrosion aspect. The cathodic protection produced by the coating endured with no corrosion damage despite coating loss of up to 40% of the circumference by wear damage. The trial also demonstrated the flexibility of the coating, as it remained intact and well-adhered to the surface despite handling and operational stresses. Furthermore, the coating withstood typical clamping pressures and mechanical damage commonly encountered in coiled rod string servicing without compromising its protective effect.

The first beneficial result of the trial for the customer was an initial improvement to MTBF by a factor of three from its historical 12-14 week rod string run time before the uncoated section suffered a fracture. The coated section of the rod string has performed in this environment for 140 weeks without failure.

[1] Norris, Sucker Rod Failure Analysis special report
[2] NACE International, IMPACT study (2016)
[3] NACE TM0185 *Evaluation of Internal Plastic Coatings for Corrosion Control of Tubular Goods by Autoclave Testing*
[4] ISO 16773 *Paints and Varnishes – Electrochemical impedance spectroscopy (EIS) on high-impedance specimens*

TABLE 1 - NACE TM0185 autoclave fluid composition and test conditions

Temperature:	150^{o}C
Pressure:	500 psi
Duration:	30 days
Gas phase:	5% H_2S, 5% CO_2, 90% CH_4
Hydrocarbon phase:	50% Kerosene, 50% Toluene
Aqueous phase:	5% NaCl in RO water
Depressurization:	Slow depressurization, approx. 10 psi/min

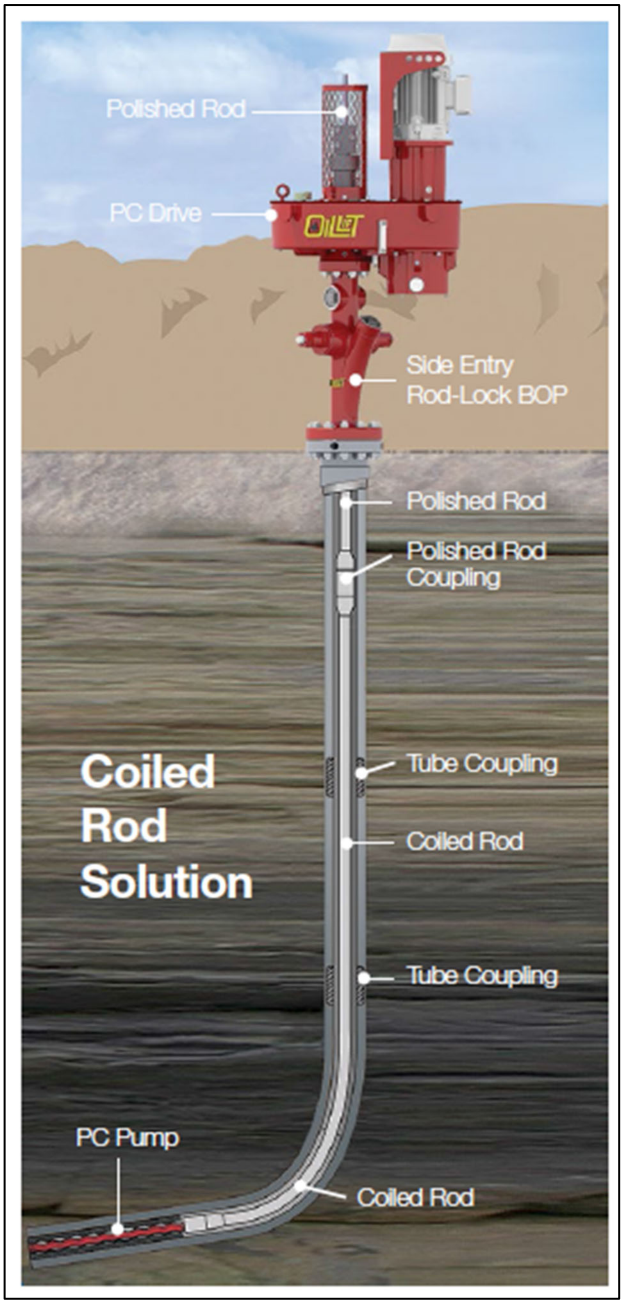

Figure 1 – Schematic of a wellbore with coiled rod

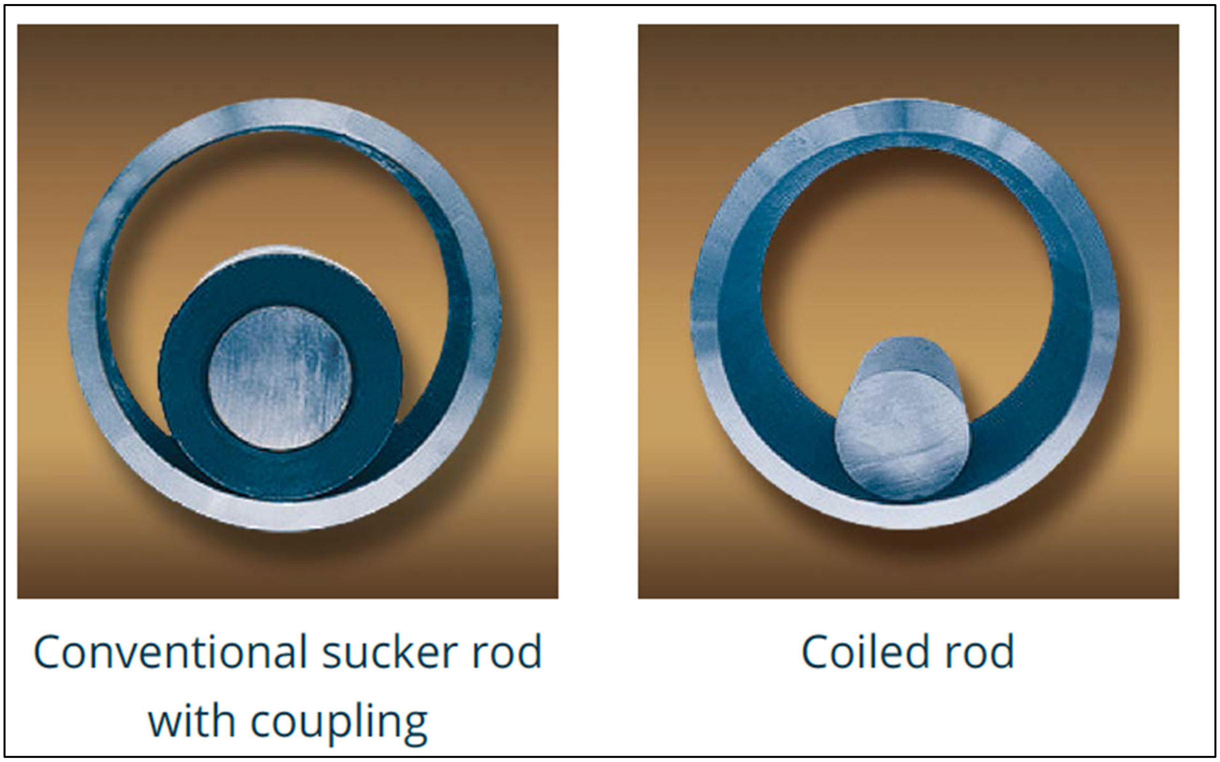

Figure 2 – Inside view of production tubing with conventional sucker rod and coiled sucker rod

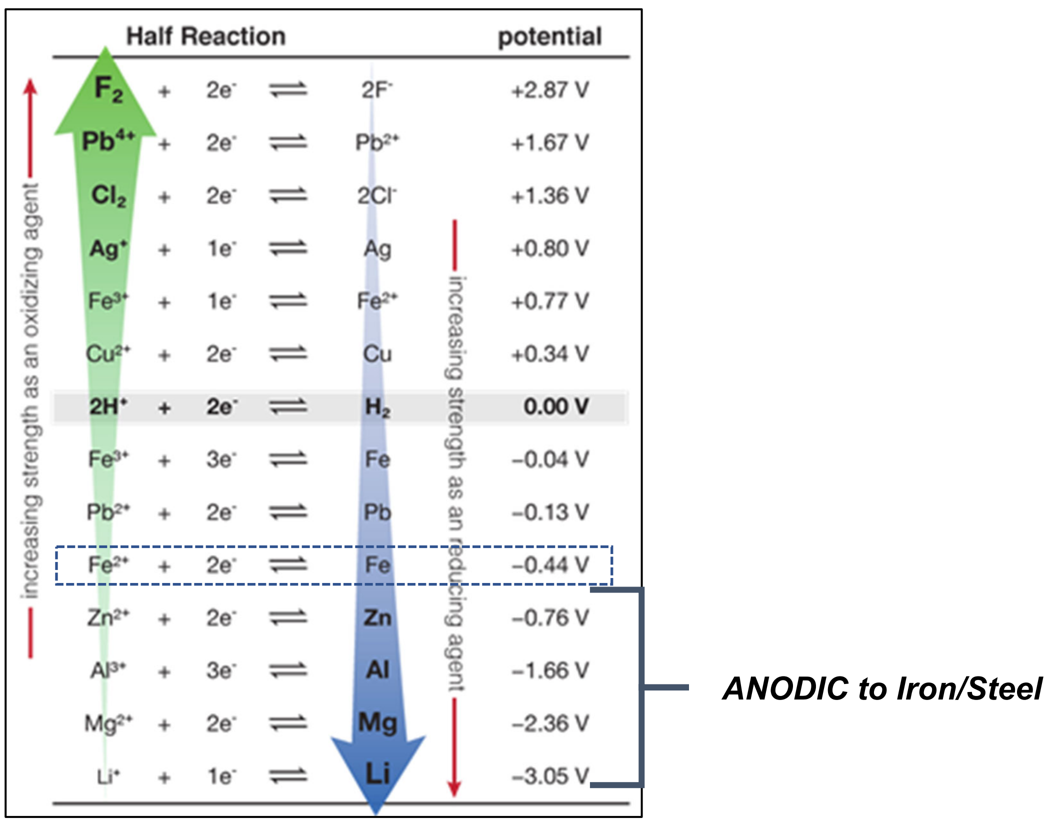

Figure 3 – Galvanic series of materials

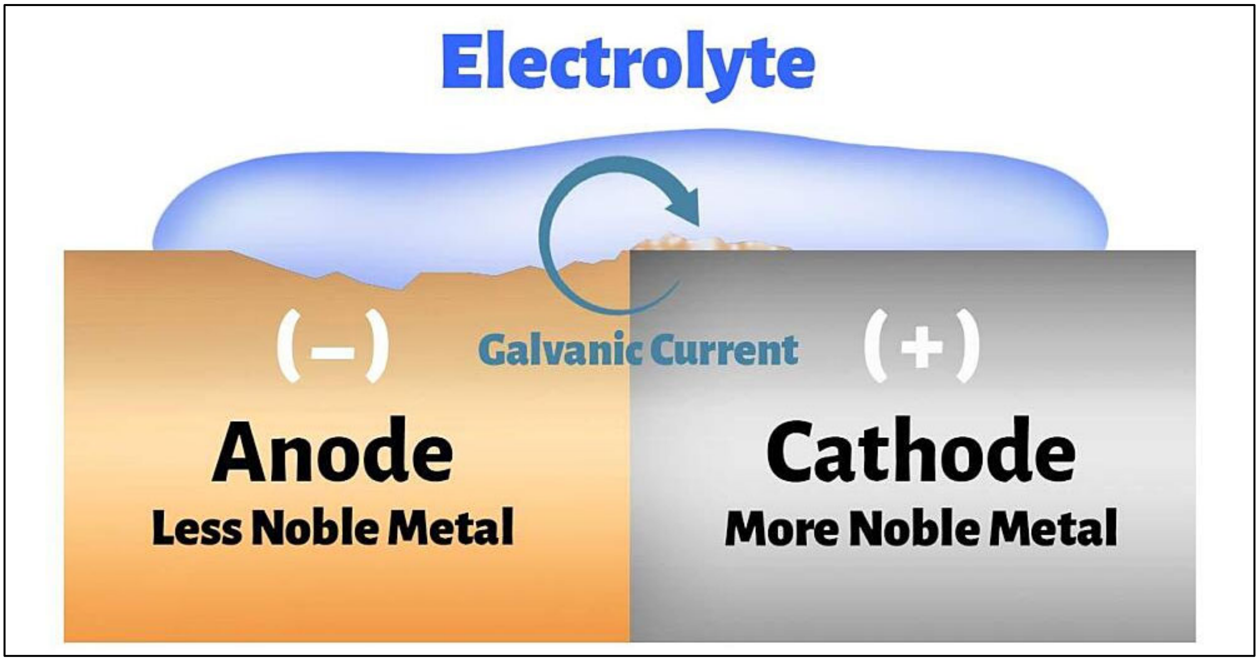

Figure 4 – Galvanic corrosion cell

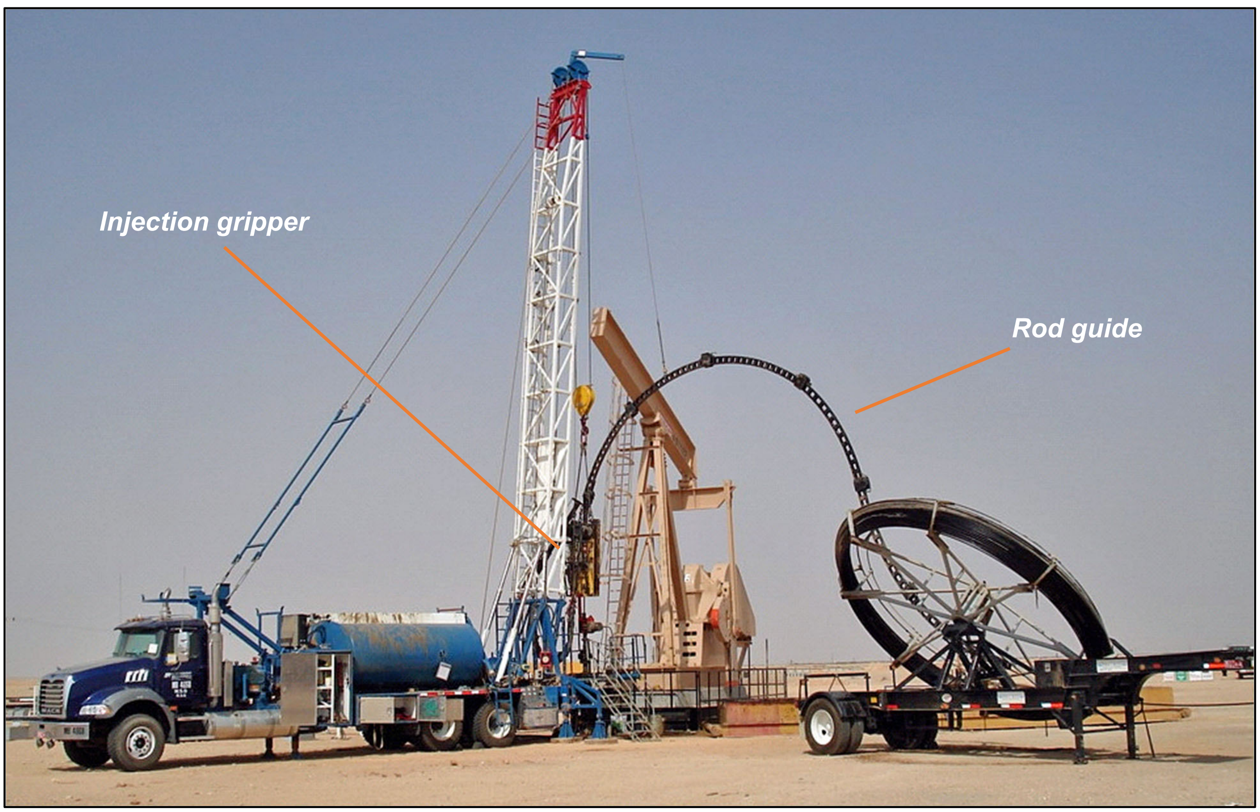

Figure 5 – Coiled rod handling equipment and transport reel

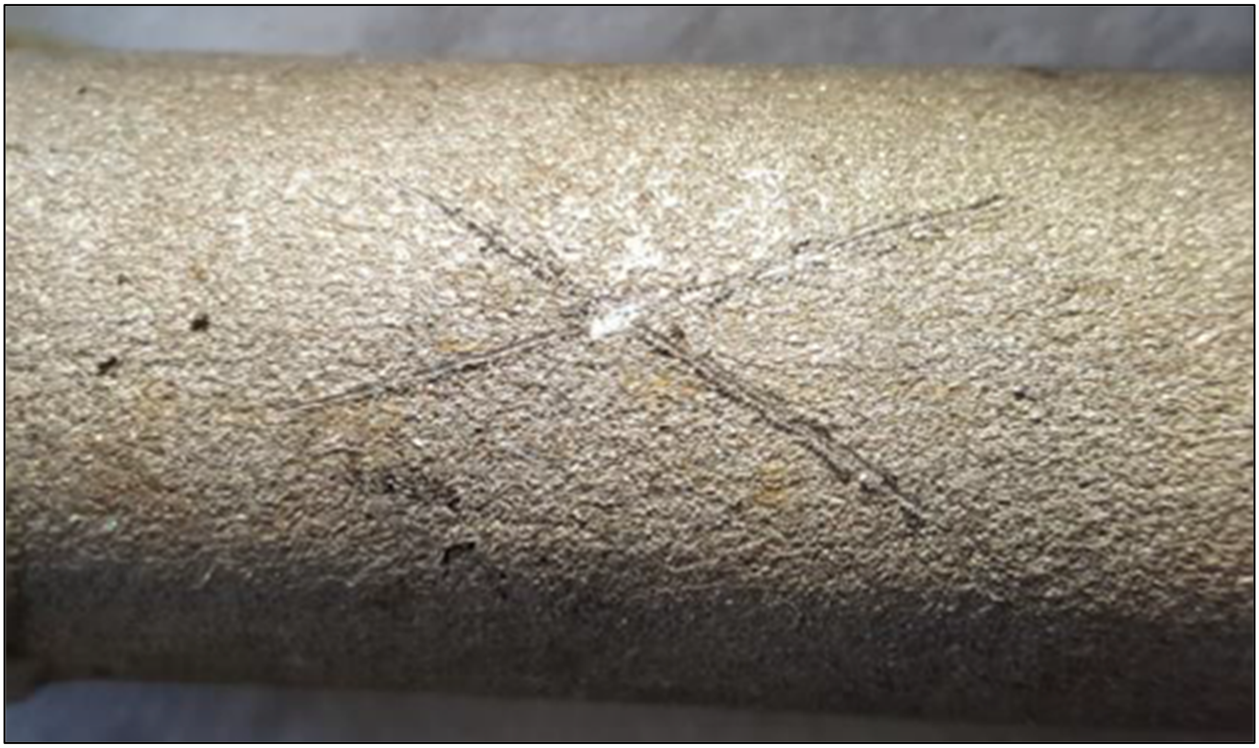

Figure 6 – X-cut evaluation of coating corrosion test

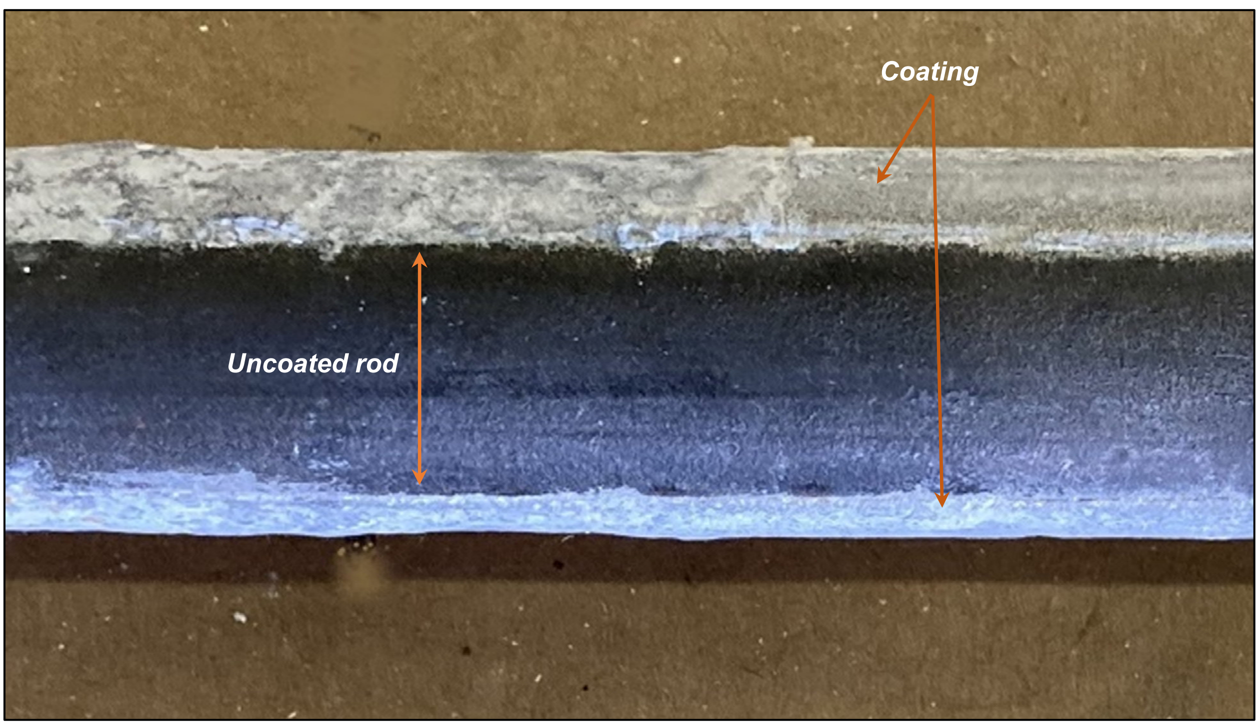

Figure 7 – Corrosion test with simulated wear damage

Figure 8 – Coated test panel bend testing

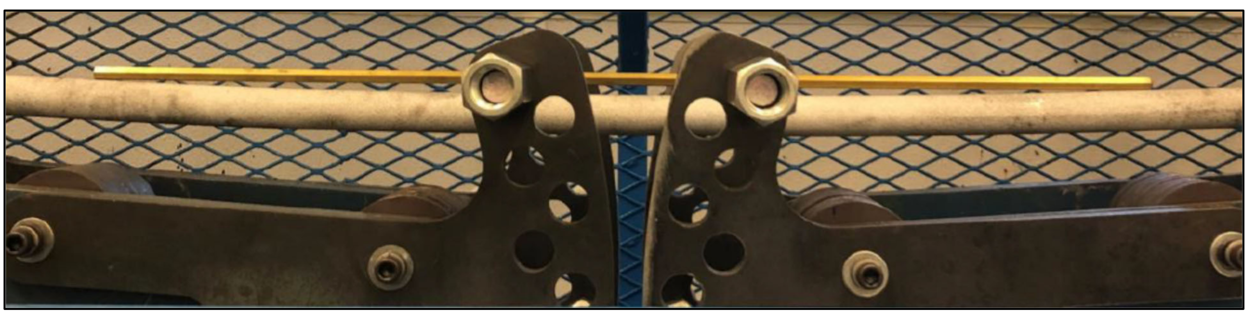

Figure 9 – Coated rod rotating bend testing (brass rod used to demonstrate rod curvature)

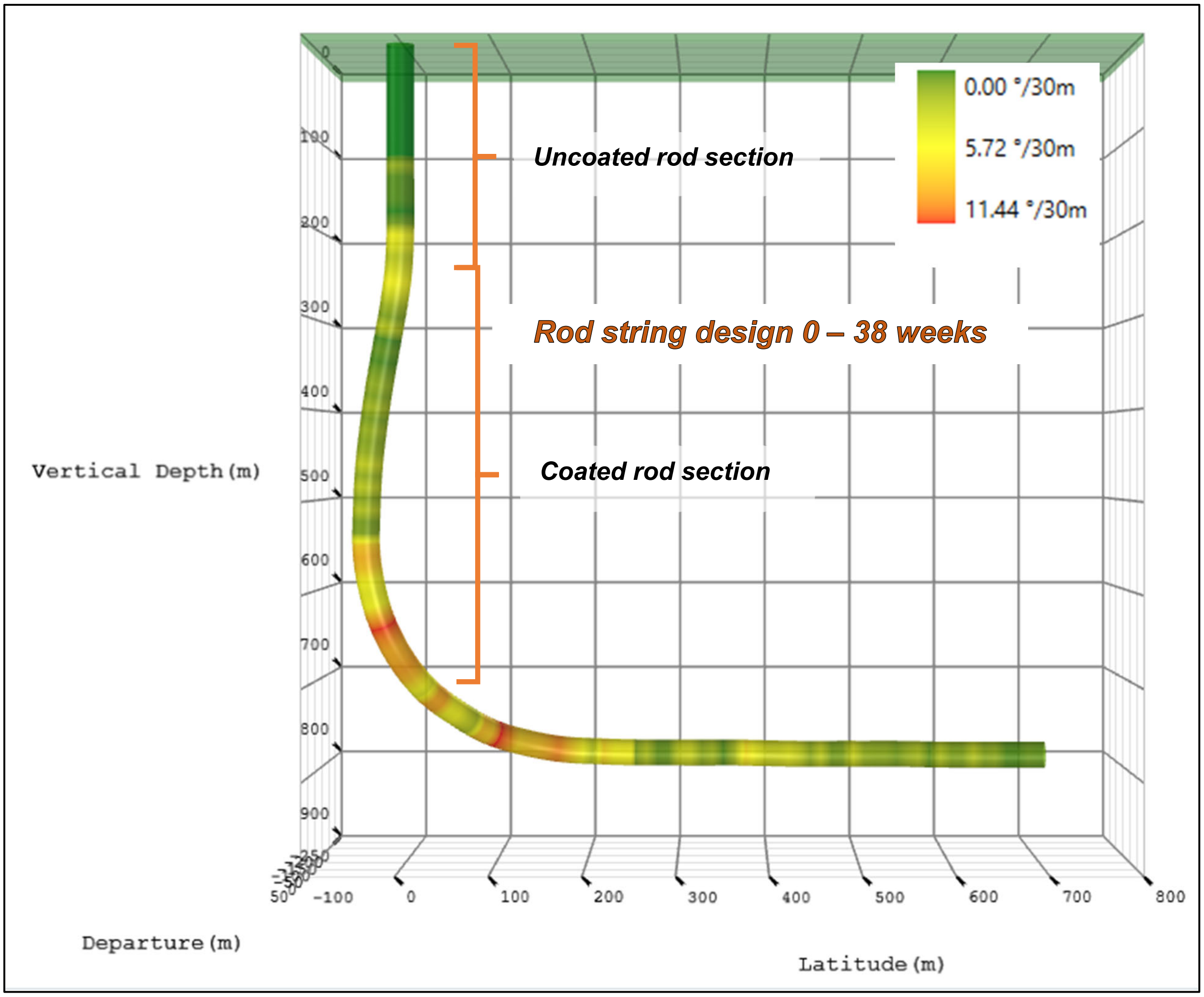

Figure 10 – Wellbore schematic including string design

Figure 11 - Uncoated rod exhibiting corrosion damage at 22 weeks

Figure 12 - Uncoated section exhibited wear near coated section (22 weeks)

Figure 13 - Coated section exhibited light wear (22 weeks)

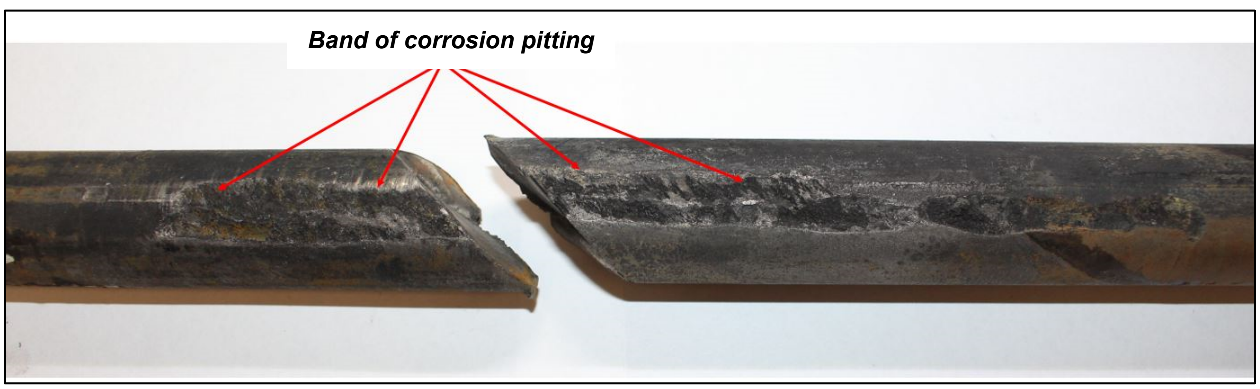

Figure 14 – Corrosion damage in uncoated section near surface (38 weeks)

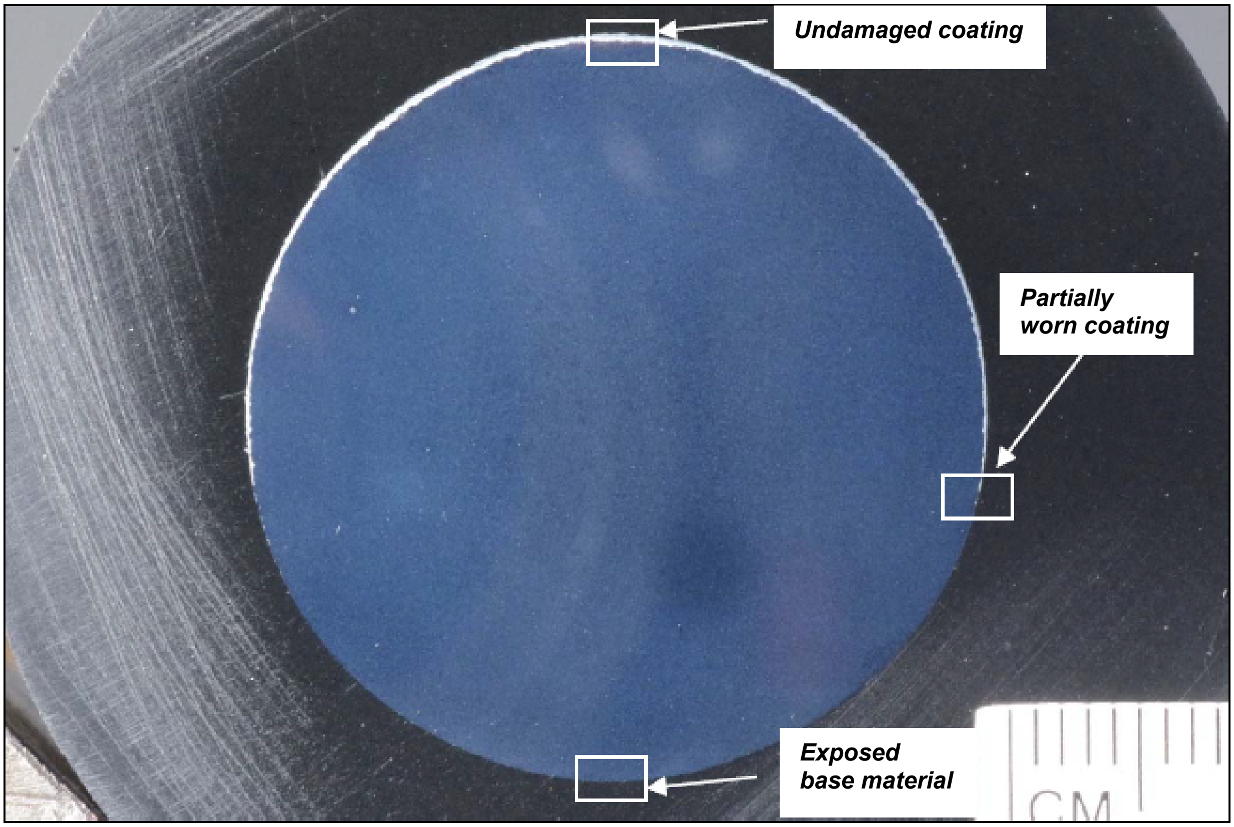

Figure 15 – Examination of coated sample from rod trial (38 weeks)

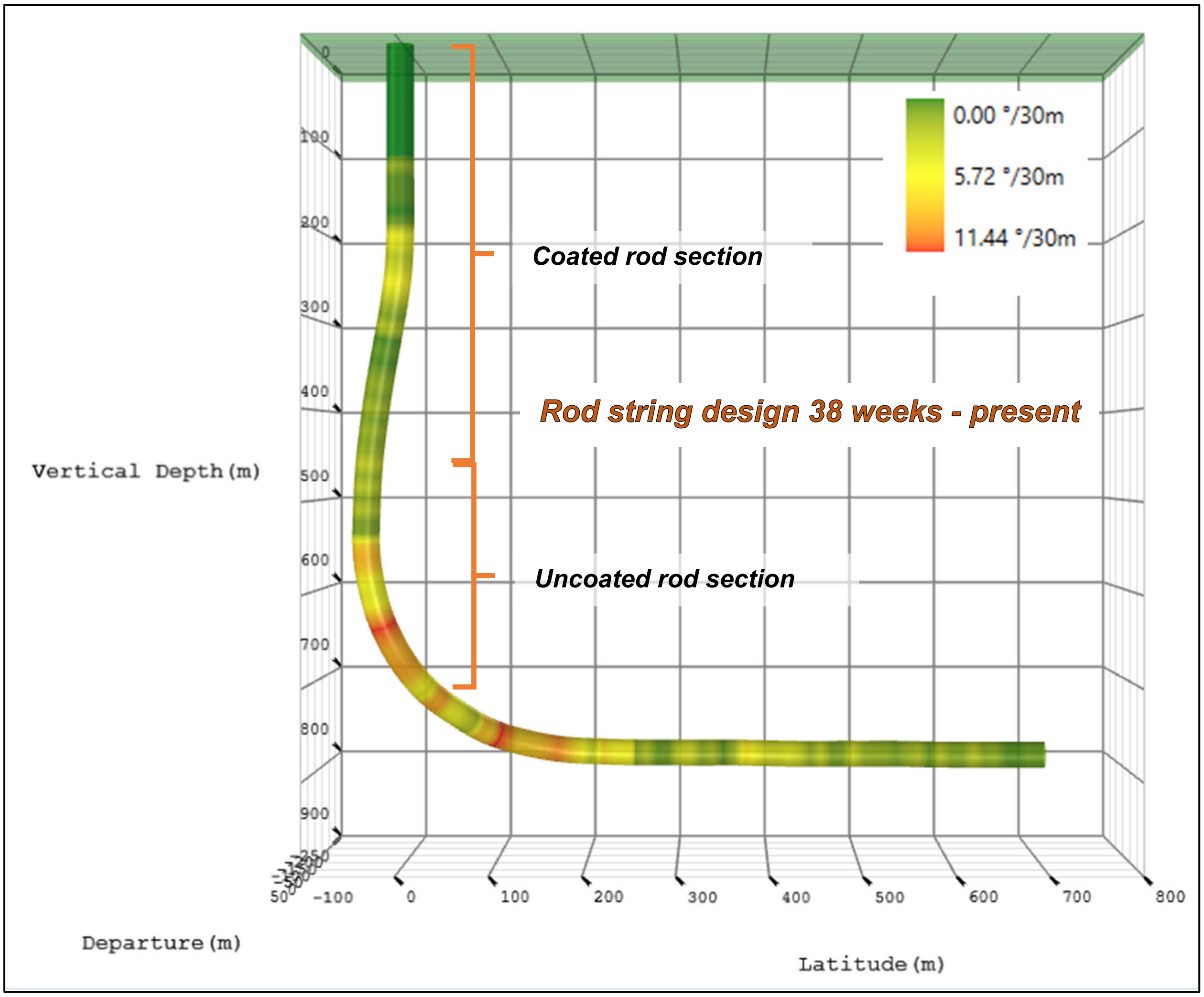

Figure 16 – Wellbore schematic including inverted string design