

## Monitoring and Management of Corrosion Rates in Water-Based Drilling Fluid Systems

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### Abstract

The proliferation of water-based drilling fluid systems due to their improved performance benefits has instigated copious amount of technical studies on the mitigation and control of their induced corrosion on downhole drilling tools and tubulars. Apart from the exorbitant costs associated with drill string wash-outs and component failures, corrosion may also induce an increase in non-productive time (NPT). Absence of effective corrosion control practices can engender corrosion rates up to 184 mils per year (mpy) in drilling operations.

This paper presents the results of drilling campaign, which utilized an oxygen scavenger, corrosion inhibitor and pipe protectant to manage corrosion. On-site monitoring and treatment of the drilling fluid and the use of corrosion rings in the mud tanks and the drill pipe made it possible to identify the corrosion management needs for each section of the well. By using data captured from daily mud reports and results from corrosion ring tests (mpy), a treatment program was designed and implemented. The corrosion rates were consistently lowered month by month as the program was adjusted for efficiency. Overall, the drill pipe and drilling rig component corrosion rates were decreased by approximately 400% to an average of 55 mpy. Incurred cost due to flat rig time of wash-outs and the replacement of drill pipe and mud system components were also reduced over time with the continuation of an effectively managed and monitored corrosion mitigation program.

### Introduction

Upsurge in energy demands has led to an increase in oil and gas drilling operations. In a bid to enhance drilling efficiency and increase Rate of Penetration (ROP), economic approaches like the use of solids free Water-Based mud systems are currently being adopted. Despite the improved efficiency of water-based systems (brines), their overall performance is hampered by the corrosion they induce on drilling equipment. Currently, divalent halide-based brines such as calcium chloride are very common in completion and drilling operations because they fill a large common density window and are profusely available. They are also relatively economical when compared to other premium salt systems, despite their large corrosion risk. It is therefore imperative to devise an effective corrosion scheme to mitigate corrosion induced by these

popular drilling fluid systems.

The majority of the equipment used in drilling operations are metallic alloys thereby susceptible to corrosion; this vulnerability can be compounded by exposure to corrosive atmospheric conditions, extreme temperatures and pressures or even harmful microorganisms. Corrosion is complicated by a variety of factors, some of which are uncontrollable and unavoidable. The majority of the problems are operational and location specific as well as the associated corrective measures. Hence, there are no global or definitive control measures for all corrosion problems (Patton 2016).

The economic impact of corrosion-related damages to the oil and gas industry, in the United States of America alone, is estimated at \$27 billion and the annual global cost is estimated to exceed \$60 billion (Papavinasam 2013). Several mitigation measures developed to battle corrosion often involve chemical measures that utilize inhibitive chemicals and mechanical measures focused on tubulars' design as well as effective operational procedures (Murray and Holman 1967; Bush 1993; Asrar 2010; Patton 2016). The optimal amalgamation of these mitigation measures coupled with trained personnel forms the basis of an effective control strategy.

Close monitoring of drilling fluid properties can also be an effective means to battle corrosion (Bush, 1974). Measuring and monitoring drilling fluids' properties can help indicate the presence of harmful corrosive agents, which can then be controlled. Very corrosive, even at very low concentrations, oxygen (O<sub>2</sub>), hydrogen sulfide (H<sub>2</sub>S) and carbon dioxide (CO<sub>2</sub>) are frequently encountered in drilling operations, making their monitoring and control a priority. The presence of harmful bacteria also constitutes a source of concern in corrosion control (Winning et al. 2010; Patton 2016). In addition, recent studies have also shown the inimical effect of drill solids on corrosion rate of downhole tubulars (Heath and Okesanya 2020). This study presents an effective corrosion control campaign, which utilized a scientific approach of physical testing of key properties, and a chemical treatment program utilizing an O<sub>2</sub>/H<sub>2</sub>S scavenger, corrosion inhibitor and pipe protectant (atmospheric corrosion inhibitor) to manage corrosion in area suffering an epidemic of drill pipe washouts. Drill pipe corrosion coupons from different wells in West Texas were utilized for experimental analysis. Industry-standard and non-standard measurement was carried out on the corrosion

coupons, rings and drilling fluids obtained from these wells to determine selected properties. Weight loss tests on drill pipe corrosion rings and coupons were used to determine field corrosion rates. Over 150 corrosion rings and coupons were utilized and the results from the weight loss evinced the efficacy of the corrosion control scheme.

## Experimental Materials and Methodology

### Material and Corrosion Testing

Corrosion coupons and rings measure the corrosive effects of the drilling fluid environment during operations. The rings and coupons are made from AISI 4130 cold-drawn seamless mechanical tubing, similar to a drill pipe. They are carefully installed in the pits or drill string while running the drill string in the hole. It is recommended to keep corrosion rings and coupons in place for a minimum of 40 hours to increase the accuracy of test results.

Drilling conditions along with ring and coupon properties are recorded (fluid properties, initial weight, time in/out, depth in/out etc.) during the test. After the bit run the corrosion rings and coupons are carefully removed, greased, placed in their original envelopes (preventing atmospheric corrosion) and sent for technical analysis. When removing the rings, care is taken to avoid any mechanical damage that could cause weight loss or damage the shell of the coated rings.

At the laboratory, the rings and coupons are photographed and cleaned with Isopropyl Alcohol (IPA) and Xylene 50:50 mix. Then, they are dipped into an inhibited acid and rinsed to dry with Methanol. Finally, they are weighed to determine corrosion rates. With original weight and K factor of each ring known, the corrosion rate can be determined using:

$$\text{Corrosion Rate (mpy)} = \frac{\text{weight loss (g)}}{\text{Exposure Time (hours)}} * K * 24.62$$

Weight-loss tests were carried out before and after treatment to check the effectiveness of the program and to justify the additional treatment costs incurred. An independent laboratory performed the corrosion analysis to the specified standards and procedures. This third-party verification increased the validity of the testing.

### Chemicals and Corrosion Control Additives

Chemical measures and operational procedures were utilized in this campaign. The main corrosion inhibitor utilized provides a film-forming amine that protects metal surfaces from corrosion and it is compatible with halide brines systems. Apart from compatibility and formation of films, the corrosion inhibitor has high temperature stability and the unique ability to not alter drilling fluid properties. It also stabilizes pH and scavenges residual O<sub>2</sub> at downhole temperatures. The corrosion inhibitor was added to the system at a concentration of 5 – 7.5 L/m<sup>3</sup> (0.5-0.75% v/v).

An O<sub>2</sub> scavenger in the form of a dry powder (for ease of handling and versatility of mixing) was also used to inhibit the formation of O<sub>2</sub> corrosion cells on metal surfaces. The product selection criteria included compatibility with divalent and

trivalent ions like Calcium or Iron, because the water sources being used varied across rigs and intervals and often contained these ions. Sulfite-based O<sub>2</sub> scavengers precipitate in the presence of these ions, so were not an option. The O<sub>2</sub> scavenger selected is fast acting and environmental friendly. It does not form scales or precipitates and it is compatible with major brine solutions including divalent brines. The O<sub>2</sub> scavenger was added to the system at a concentration of 0.5 - 12 kg/m<sup>3</sup> (0.2 - 5 ppb), depending on O<sub>2</sub> levels present in the Fluid system. The product depletes as it scavenges O<sub>2</sub> from the drilling fluids. The O<sub>2</sub> content was monitored using Hach 2100Q dissolved O<sub>2</sub> meter. Drilling fluid systems are constantly being aerated across turbulent processes in solids control and mixing operations hence requiring continuous deoxygenation.

An H<sub>2</sub>S scavenger was also incorporated in the corrosion control plan. This was due to the notoriety of H<sub>2</sub>S in the region. The environmental friendly and non-ionic H<sub>2</sub>S scavenger was developed for use in brine systems and does not form scales. This H<sub>2</sub>S scavenger is highly effective at neutral acidity environments and does not deplete on drill cuttings, thereby making it suitable during pre-treatment. On an average, the utilized H<sub>2</sub>S scavenger removes 40 ppm of H<sub>2</sub>S per 1000 ppm of scavenger added. The H<sub>2</sub>S content was monitored using Hach Hydrogen sulfide test kits.

The H<sub>2</sub>S scavenger also had biocidal tendencies, which eliminated the need of including additional expensive biocides in the corrosion control plan. Because the H<sub>2</sub>S scavenger was used intermittently and freshwater additions contained bacteria, additions were treated cost-effectively with Sodium Hypochlorite (bleach). Bacteria testing was conducted using BART (Biological Activity Reaction Test) Bottles, which, detect Iron-Reducing (IRB), Sulfide Reducing (SRB), and Acid Producing (APB) bacteria types.

While most chemical corrosion control program often consist only of Corrosion inhibitor, H<sub>2</sub>S and O<sub>2</sub> scavengers, this campaign went a step further and included a pipe protecting, atmospheric corrosion inhibitor as well. The pipe protector is applied to racked pipe through spraying or wiping. The environmental friendly, thermally stable pipe protector is a certified and safe product that poses no health risk to onsite workers. The pipe protector acts by coating metal surfaces and protecting the metal from atmospheric corrosion. It provides further defense to drill pipe and downhole tools that are exposed to air while being stored on surface and absorbs physically and chemically on metal surfaces displacing corrosive brine fluids.

## Corrosion Program Implementation and Operational Procedures

### Prior Corrosion Program

Unmanned corrosion chemical injection units were the used in the area. They offer a facile means of continuous additions of corrosion chemicals to the active drilling fluid system. However, after an epidemic of drill pipe washout occurring on approximately 40-50% of all wells being drilled, there was a need to reassess the current corrosion program.

These units worked through metering in minor amounts of chemical. However, the same chemistry would be used across

all intervals, which led to some errors in the application. As stated earlier each corrosion control strategy is problem specific. The drilling program included at least three different types of brine sources and fluids systems to be treated (Figure 1). These included a saturated sodium chloride, a low chloride bentonite system, a viscosified light brine for the production zone, as well as a mixture of produced water and solids. Each one of these brine sources had to be initially characterized to avoid incompatibilities with corrosion chemicals and the water chemistry. Additionally, there was little attention paid to treatments rates and effectiveness at the predetermined injection rate. This often resulted in the under treatment of the system, especially in regards to O<sub>2</sub> scavengers.



**Figure 1 – Water Storage Pits**

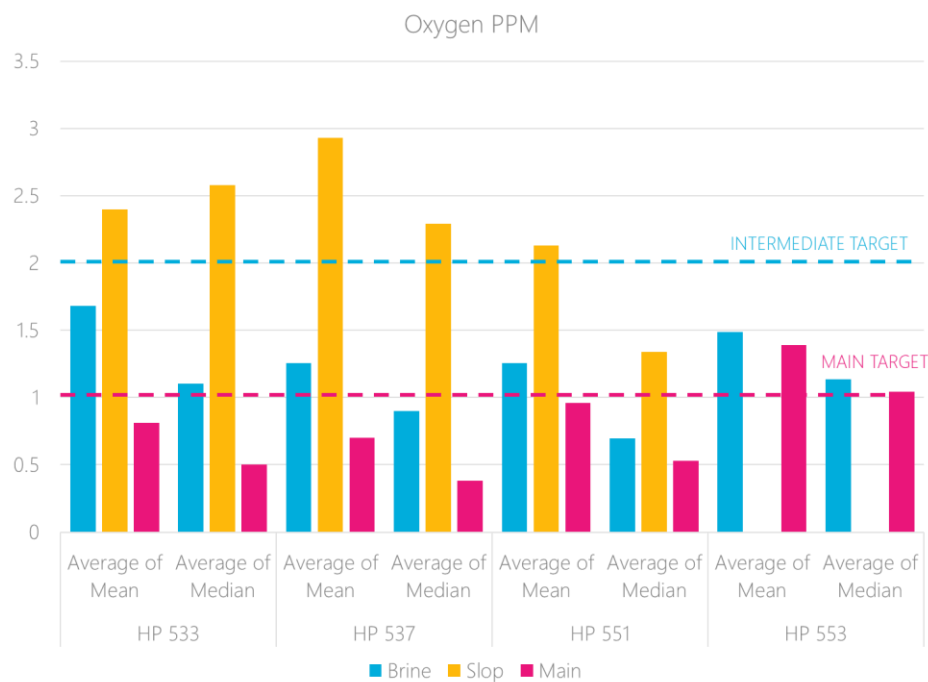
In order to determine a chemical treatment path, water analysis of the various intervals had to be performed. Each water presented its own specific challenges. The sodium chloride interval had the highest salinity and expected highest corrosion rates. The low chloride bentonite fluid was used in zones with heavy losses and high in H<sub>2</sub>S. This required a treatment plan that was both cost effective and easy to execute.

The drill pipe and components were exposed to the viscosified light brine the longest. This, coupled with higher temperatures and pressures required the use of additional O<sub>2</sub> scavenger and corrosion inhibitor.

### Oxygen Monitoring and Control

Oxygen is by far the one of the most corrosive gases that is encountered during drilling operations (Murray and Holman 1967; Bertness, Chilingarian and Al-Bassam 1989). Some experts even claim 1 ppm of O<sub>2</sub> might be even more corrosive than 50 ppm H<sub>2</sub>S. Detailed pipe inspections done in the Area prior to the implementation of the program revealed O<sub>2</sub> was the main culprit for pipe degradation. Initial O<sub>2</sub> concentration before implementation of the program were between 7 and 9 ppm, which is detrimentally high and a leading cause of excessive pitting.

One of the initial steps was to start continuous O<sub>2</sub> monitoring to ensure that it was treated to levels below known thresholds that typically lead to excessive O<sub>2</sub> pitting and corrosion from prior experience. An O<sub>2</sub> target of below 2 ppm for the intermediate section and below 1 ppm for the lateral was chosen based off of the known temperature and corrosion potential data of the two fluids. These targets would be validated across multiple data points using the corrosion rings and coupons as a guideline for too high or too low of a treatment rate. A dissolved O<sub>2</sub> meter was used to determine the excess O<sub>2</sub> in the active system and to ensure proper treatments with O<sub>2</sub> scavenger while drilling ahead. As earlier stated, due to the different water systems it was important to select an O<sub>2</sub> scavenger that would not precipitate in the presence of divalent or trivalent ions such as Ca<sup>2+</sup> and Fe<sup>2+</sup>/Fe<sup>3+</sup> that was often seen in the water sources that were being used. The results of O<sub>2</sub> monitoring in some of the wells are shown in Figure 2.



**Figure 2 – Oxygen Monitoring**

### Bacteria Monitoring

Although it is hard to quantify microbial induced corrosion, there were instances in the past of biofilms being discovered on drill pipe that may have an influence on the damages. Due to past testing by the operator, it was known that bacteria was present in the system, especially in the production water brine. However, a treatment program had not yet been developed or implemented. Hence, a full scale bacteria monitoring program was initiated that looked at Iron Reducing Bacteria (IRBs), Sulfate Reducing Bacteria (SRBs), Acid Producing Bacteria (APBs), and Slime forming species. This would be carried out across the fresh water source used for makeup volume, the sodium chloride brine, the produced water brine and the lateral water based mud system. The production water (also called “black water”) exhibited a high severity degree of bacteria across the board including SRBs, IRBs, and APBs. Surprisingly, it was discovered the fresh water source was also a primary contributor to bacteria in the system in the form of IRBs, and to a lesser extent APBs. This fresh water source was a main component of the low chloride bentonite system, the fluid used in the laterals and was also used to hydrate flocculating polymers in the saturated sodium chloride brine. A program using Sodium Hypochlorite was implemented to treat all fresh water additions going forward to with the effectiveness of the treatments assessed using bug bottles.

### Chemical Treatments

Corrosion inhibitive chemicals described in the Chemicals and Corrosion Control Additives section were initially maintain at 1.5 - 3 ppb in the fluid system. For the initial intermediate interval, corrosion rings were run in the drill string and coupons in the surface tanks. They were evaluated to determine corrosion severity in the top hole, and whether it warranted additional chemical treatment. Based on the results, there were additional increases in the concentration of chemicals added to the system. Increase in O<sub>2</sub> or H<sub>2</sub>S led to an increase in the concentration of scavengers added to the system. Most chemicals were mixed in the suction tank depending on the required concentration based on the test results.

### Post Well Drill Pipe Protection

There was also a concern on the potential corrosion damage that may occur due to direct exposure to atmospheric conditions and weather cycles in West Texas air. Typically, humid wet and dry cycles when combined with heat can produce atmospheric corrosion (Bush 1994; Asrar 2010; Groyzman 2017). A drill pipe protectant different from the corrosion inhibitor was also utilized before storing the tubulars on surface. During the final trip out of the well, the protectant was sprayed on the exterior of the drillpipe and then slugged down the inside of the pipe. It coated the pipe by adsorbing onto the metal surface and displacing off any remaining brine fluid

### Summary of Corrosion Control Treatment and Operational Procedures

Trained personnel were responsible for ensuring best corrosion control practices were followed which included pH measurements in high salinity brines, corrosion ring handling procedures, product mixing, and O<sub>2</sub> testing. The major treatment practices are as follows;

- Maintain Dissolved Oxygen (DO) concentration below 1-2 ppm at all times.
- Measure DO meters twice daily from pits and suction tank then treat with O<sub>2</sub> scavenger based on results.
- Monitor and maintain H<sub>2</sub>S concentration below 5 ppm using Hach Meters and H<sub>2</sub>S scavenger.
- Initially maintain 1.5 - 3 ppb of corrosion inhibitors in the fluid system.
- Carefully analyze coupons and target corrosion rate of 50 mpy or less without observed pitting. The severity of results determines whether fluid systems warrants additional increase of chemical treatments.
- Apply pipe protectant on racked pipe through spraying or wiping.

### Results of the Corrosion Treatment

#### Bacteria Treatment Corrosion Results

Samples of fresh water were taken from the central fresh pond. Untreated freshwater was compared against water treated with Sodium Hypochlorite at 10 ppm concentration. The samples were also tested for the presence of various bacteria colonies. Results pointed to extremely high bacteria levels but also demonstrated the effectiveness of removing them through sodium hypochlorite treatment of fresh water ponds (Figure 3).

Table 1: Outcome of 10 ppm bleach treatment of Brine Water Pit

	UNTREATED	10 PPM BLEACH
SULPHATE REDUCING BACTERIA	Aggressive	Not Aggressive
IRON RELATED BACTERIA	Aggressive	Not Aggressive
SLIME	Moderate	Not Aggressive
ACID PRODUCING BACTERIA	Aggressive	Not Aggressive



Figure 3 – Results of Bacteria Test

### Post Well Drill Pipe Protection Results

The efficacy of the pipe protectant was adjudicated using weight loss tests. Comparative analysis using coupons submerged in the active drilling fluid system for 48 hours (Figure 4) and then left outside for 1 week showed that coupons not coated the protectant had a 50% higher corrosion rate than those not coated with the protectant. Even visual analysis of both coupons indicates the severe deterioration on the uncoated

coupon than the coated coupon.



**Figure 4 – Protectant-Treated Coupon on the Left and Untreated Coupon on the Right**

Visual analysis of drill pipes (Figure 5) also showed a clear distinction between pipes coated with the protectant and those not coated. The pipes not coated with the pipe protectant appeared rusty and corrosion infested while those coated exhibited near pristine appearance.

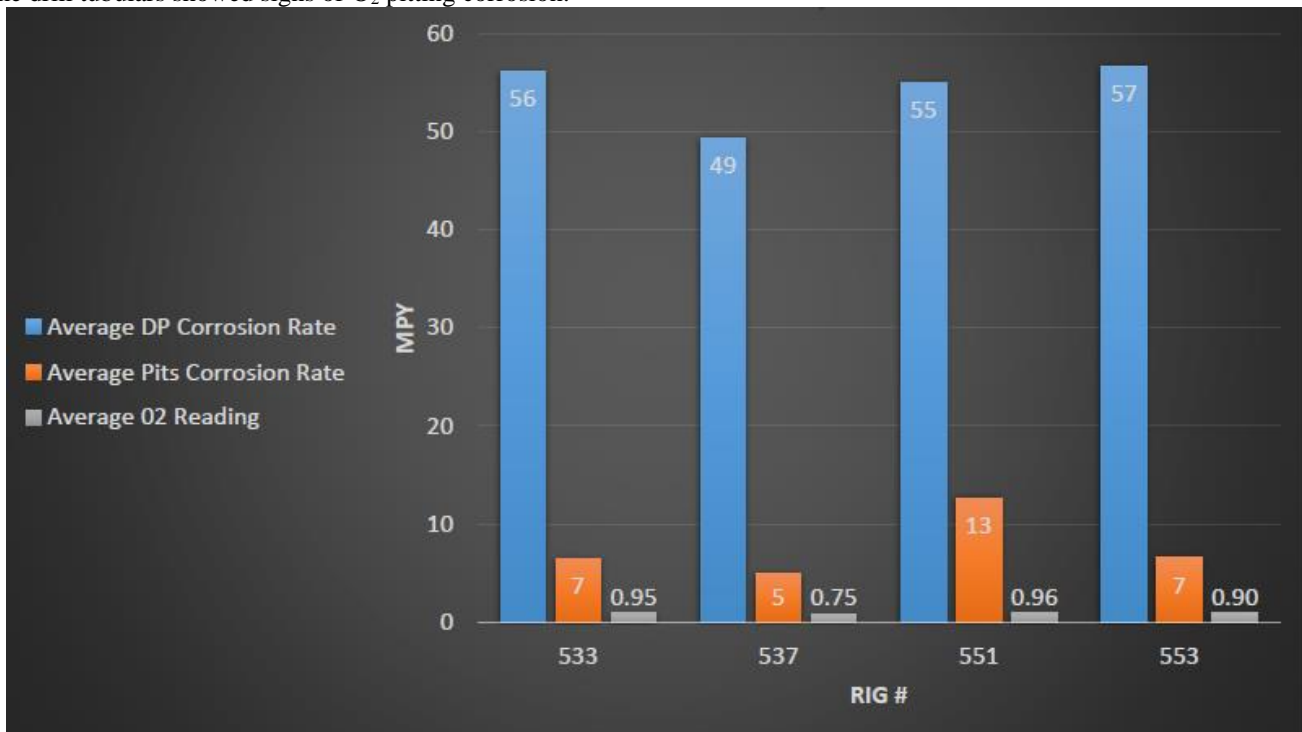
### Corrosion Rate Results

This section presents the major outcome of the campaign. As earlier stated, there was an epidemic of drill pipe washout occurring on approximately 40-50% of all wells being drilled in the area. The average corrosion rate before the inception of the program was over 180 mpy. An investigation before the program implementation showed that  $O_2$  was one of the main causes of corrosion and the pipe deterioration. Visual analysis of some drill tubulars showed signs of  $O_2$  pitting corrosion.



**Figure 5 – Effect of Protectant (Left side: Pipes coated with protectant and Right side: Pipes not coated with protectant)**

Upon the switch to the new corrosion plan, a single ring was run for a benchmark in the intermediate hole. It registered 184 mpy with no treatments being made for the intermediate section, which consisted of a saturated sodium chloride section with a flip over to a produced water system prior to known loss zone. The corrosion plan was implemented with initial results



**Figure 6 – Average Corrosion Rates of Coupons in Drill pipes/Pits and Measured Oxygen Concentration**

showing an average of about 70 mpy for all corrosion rings run in the drill string across both intermediate and production intervals, along with 12 mpy for coupons that were used in the fluid pits.

Although the top hole fluid conditions proved to be more corrosive than the lateral section, nonetheless the average corrosion rate in the drill pipes was less than 75 mpy and less than 10 mpy in the pits. The observed higher corrosion rate average was due to lost circulation events that resulted in under-treatment of additives and resulting high corrosion rates. More losses often translate to higher volumes of untreated fluid since some corrosion inhibitive chemicals are lost as well. There was also the potential of a higher occurrence of other corrosive agents such as H<sub>2</sub>S and microbes, although there is no evidence as to Sulfide related corrosion, and microbial induced corrosion.

As the personnel become more proficient and acquainted with the treatment program, a drastic improvement in the corrosion rate occurred. Subsequent months have showed a steady improvement in corrosion rates as the procedures and plans were followed closer with an O<sub>2</sub> target change of below 1ppm for the intermediate section applied in October 2019, which resulted in a further drop in corrosion rate averages. Average monthly corrosion rates decreased from 70 mpy to 23 mpy (67% decrease) since the inception of the program and pitting has not been observed on the coupons. The overall corrosion rate has been reduced from over 180 mpy (before implementation) to 23 mpy (Figure 7). The O<sub>2</sub> concentration was progressively reduced from 7 ppm to 0.9 ppm (Over 650% decrease) (Figure 6). All these resulted in significant increase in the life of the new drill pipes and additional savings in

corrosion damage cost.

There was however, an increase in corrosion rate averages as a new rig was brought into the program in December 2019. The on-boarding of new rig crews and personal unfamiliar with the O<sub>2</sub> monitoring and corrosion treatments had brought up the average for the month of December. This highlights the importance of process and procedures in managing corrosion on a well site.

## Conclusions

In summary, this study presents the results of effective corrosion control campaign, which utilized an O<sub>2</sub>/H<sub>2</sub>S scavenger, corrosion inhibitor biocides, and pipe protectant (atmospheric corrosion inhibitor) to manage corrosion in area suffering an epidemic of drill pipe washouts with a high correction rate of 184 mpy or greater. The effective corrosion program involved an optimal amalgamation of effective products, potent operational procedures and proficient personnel, which ensured its success.

Detailed pipe inspections done in the area before the implementation of the program revealed O<sub>2</sub> was the major cause for pipe degradation and washouts. Continuous monitoring and control of O<sub>2</sub> monitoring was vital to the success of the program. The O<sub>2</sub> level was kept below 2 ppm from the 7 ppm witnessed prior to the implementation of the program with aid of newly developed O<sub>2</sub> scavenger. Apart from protective film-forming corrosion inhibitor and O<sub>2</sub> scavenger, H<sub>2</sub>S and harmful microbial activity were controlled using H<sub>2</sub>S scavengers and Sodium Hypochlorite respectively. This campaign went further to include a pipe protector (atmospheric corrosion inhibitor) to the corrosion control program.



Figure 7 – Continuous Improvements and Process Learnings Over Time

Corrosion results of the program showed that the overall corrosion rate was reduced from 184 mpy (before implementation) to 39 mpy. The DO<sub>2</sub> concentration was progressively reduced from 7 ppm to 0.9 ppm (over 650% decrease). All these resulted in significant increase in the life of the new drill pipes and additional savings in corrosion damage cost.

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### Nomenclature

<i>NPT</i>	= <i>Non-Productive Time</i>
<i>mpy</i>	= <i>Corrosion rate in Milliliters per year</i>
<i>ROP</i>	= <i>Rate of Penetration</i>
<i>O<sub>2</sub></i>	= <i>Oxygen</i>
<i>H<sub>2</sub>S</i>	= <i>Hydrogen Sulfide</i>
<i>CO<sub>2</sub></i>	= <i>Carbon Dioxide</i>
<i>AISI</i>	= <i>American Iron and Steel Institute</i>
<i>IPA</i>	= <i>Isopropyl Alcohol</i>
<i>K factor</i>	= <i>Bend Allowance</i>
<i>g</i>	= <i>Grams</i>
<i>pH</i>	= <i>Logarithmic scale of hydrogen ion concentration</i>
<i>L/m<sub>3</sub></i>	= <i>Liters per cubic meter</i>
<i>%v/v</i>	= <i>Volume to volume percent ratio</i>
<i>kg/m<sub>3</sub></i>	= <i>Kilogram per cubic meter</i>
<i>ppb</i>	= <i>Pound<sub>f</sub> per oilfield barrel</i>
<i>ppm</i>	= <i>Parts per million</i>
<i>BART</i>	= <i>Biological Activity Reaction Test</i>
<i>IRB</i>	= <i>Iron Reducing Bacteria</i>
<i>SRB</i>	= <i>Sulfide Reducing Bacteria</i>
<i>APB</i>	= <i>Acid Producing Bacteria</i>
<i>DO</i>	= <i>Dissolved Oxygen</i>
<i>DP</i>	= <i>Drillpipe</i>

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