Case Study: Field Evaluation of Corrosion Inhibitors in Acidic Geothermal Fluid

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ABSTRACT

The use of acidic geothermal fluids remains a prominent challenge to geothermal power plants because severe, costly corrosion of the steel piping in wellbore casings and the surface facility can occur. Until recently, no solutions were available to mitigate corrosion without producing potentially deleterious by-products.

Generally, in Indonesia, caustic soda (NaOH) has been used to neutralize acidic brines and reduce corrosion rates. However, the addition of caustic can lead to precipitation of mineral salts, which decreases pipe diameter and reduces power generation. This led to the development and field evaluation of a new corrosion inhibitor, GeoSol™ GS3336.

This paper documents the results from a series of field tests that were conducted to optimize corrosion inhibitor dosing. Corrosion coupons, electrical resistance corrosion probes, and brine chemistry samples were monitored and analyzed to quantify the performance of this chemical treatment strategy. Additionally, a comparison of the caustic and corrosion inhibitor treatments was performed to contrast the change in pressure in the system. The field trials with this corrosion inhibitor resulted in a three-fold reduction in average corrosion rate, as compared with conventional caustic injection, without causing deposition of mineral scales in the surface piping.

1. Introduction

One of the current limitations to developing geothermal resources for electricity generation is the mitigation of corrosive geothermal fluids. Recent research and development of new corrosion inhibitors have led to a successful application compared with caustic usage. The inhibitor has been used and compared with the traditional method with a result of a three-fold reduction in average corrosion rate without causing any mineral scales deposition in the surface piping.

Historically, NaOH is injected to raise the pH level to maintain corrosion at a low and acceptable rate. However, the injection of caustic must be in sufficient quantities to achieve the desired pH level to obtain effective corrosion control. Insufficient NaOH resulted in weak and non-protective film (Lichti, 2010) while excessive NaOH precipitated other by-product minerals, including silica and metal silicates (Siahaan, 2020). Finally, pH adjustment upstream with caustic may require subsequent pH adjustment downstream with acid, which adds additional cost to the treatment program, to avoid mineral scaling. These comparisons will be discussed and compared with the inhibitor's results in this paper.

This paper summarizes the field evaluation of the GeoSol™ GS3336 corrosion inhibitor during which the corrosion rate was monitored in a single production line from the wellhead down to the accumulator outlet. The corrosion rate was reviewed for approximately 3 months during blank tests (no added chemicals), caustic dosage treatments, and inhibitor injections.

2. Background

Corrosion monitoring and control was conducted on a production line located in one of the Sarulla Operations Ltd (SOL) fields, which is a joint operating body that has a Geothermal Working Area in North Tapanuli, North Sumatera, Indonesia. The field generates 3 units x 110 MW for a total of 330 MW. As one of the biggest producing geothermal plants in the world, it has experienced corrosion issues that cause leakages at weld joints and pipe elbows.

The use of the pH modification method, caustic injection, to achieve the desired pH level was found to be difficult (See Figure 1). Injection of an insufficient quantity of NaOH resulted in a low pH, which caused the aggressive brine to corrode the surface facilities.

Figure 1: Caustic rate addition and pH level in the production line.

3. Evaluation Method

To evaluate the corrosion rate, an electrical resistance corrosion probe was placed after the accumulator outlet (SP#3). Corrosion coupons were installed both in two-phase and one-phase lines after the MOV (Motor Operated Valve) or SP#1 and the accumulator outlet (SP#3), respectively, using retractable coupon holders. (Coupons were inserted approximately 15.7” into the 20” pipe.) Additionally, brine samples were collected for field chemistry measurements and laboratory analysis. The brine sample collection points were the same as the coupon sampling points (See Figure 2).

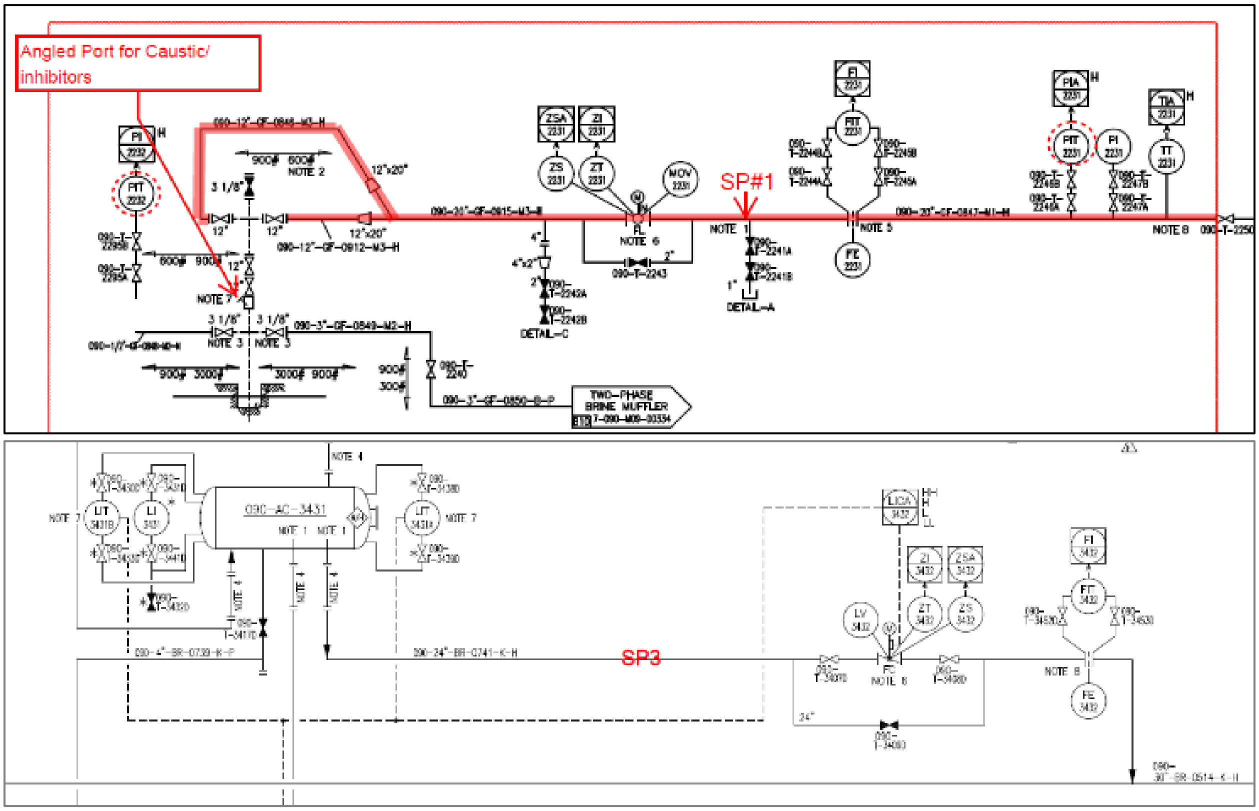


Figure 2: Piping and instrumentation diagram describes sampling points: SP#1 (top) and SP#3 (bottom).

3.1 Coupon Exposure Gravimetric (Mass-loss) Method

The mass-loss coupon exposure method is by far the most frequently used method for all geothermal corrosion trials (Nogara and Zarrouk, 2018). The mass-loss technique was calculated by exposing metal coupons, composed of material similar to the pipework, to a process geothermal fluid for a given duration and then retrieving the coupons for inspection, cleaning, and weighing. The exposure is normally for 90 days. However, in this case, useful data was attained after 18 days. The accumulated corrosion rate for the exposure period was determined by weight loss using the following equation.

$$Corrosion\ Rate = \frac{(K \times W)}{(A \times T \times D)} \tag{1}$$

where K, W, A, T, D are a constant, mass loss measured in grams (corrected for any loss during cleaning), area in cm^2 to the nearest 0.01 cm^2, time of exposure in hours to the nearest 0.01 h, and density in g/cm^3, respectively.

The mass-loss method has been used in conjunction with electrical resistance and brine chemistry to calibrate the result in the experiments to evaluate corrosion rate because the coupons are not able to identify the time of occurrence if or when a corrosion upset occurs during a field evaluation.

While A53B coupons are closer to the actual pipe material, C1010 mild steel coupons were used because of their availability. The material of the coupons may have contributed to the higher corrosion rate that will be discussed in the results section.

3.2 Electrical Resistance Method

The electrical resistance method measures the corrosion rate by detecting the gradual increase in electrical resistance of a metal element having a well-defined cross-sectional area. Any loss of metal due to corrosion leads to increased electrical resistance. Compared with the weight loss coupon method, the electrical resistance method has a far shorter response time. The corrosion rate calculation is given by the following equation.

$$Corrosion\ Rate = \frac{(P \times 365(S2 - S1))}{\Delta T} \tag{2}$$

where P, S, ΔT are probe life that incorporates mass loss by the geometric dimensions of the probe (provided by probe manufacturer), instrument readings (between time intervals), and time intervals between probe readings, respectively.

3.3 Brine Chemistry

Dissolved iron (Fe) analyses were monitored routinely on-site to assess surface corrosion rates. The Fe sample was treated with nitric acid (1.5% HNO_3) before the Total Fe is measured because the acid dissolves the insoluble Fe and converts it into soluble Fe. Any increase in Fe content in the surface plant indicates corrosion of steel tubing. The brine pH was checked on-site using the pH meter.

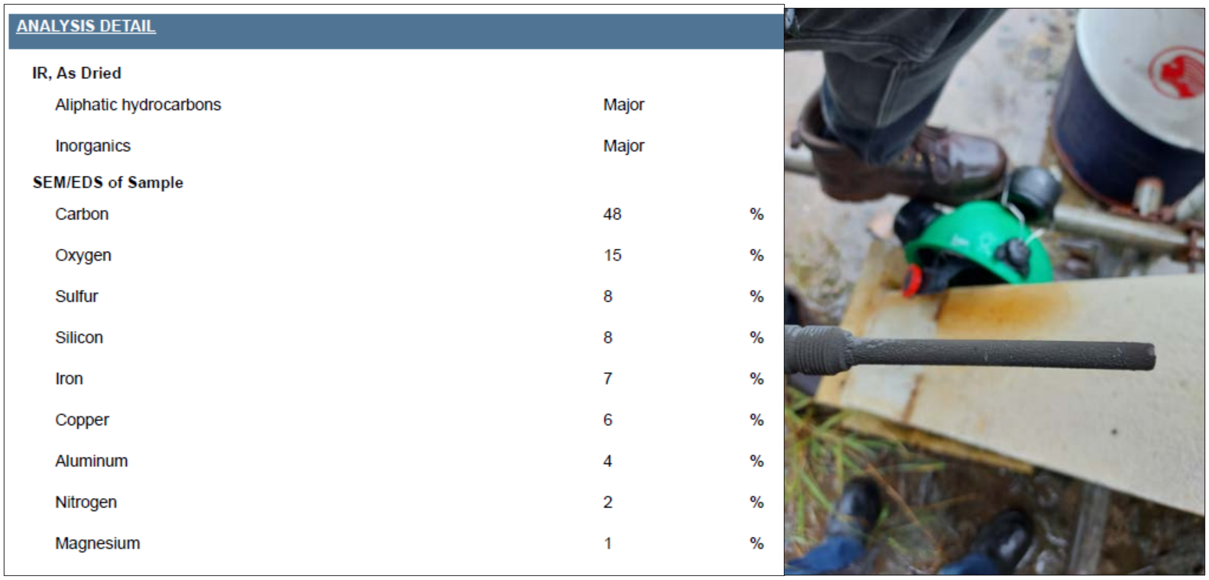
4. Results

The field evaluation was carried out for 3 months and the results are described below.

4.1 Correlation between Fe and Corrosion Rate

The primary objective of the evaluation was to measure corrosion rates on the surface as a function of inhibitor concentration. The inhibitor was evaluated for 3 months in a series of field tests to find the optimum dosage. Testing started with a 30-ppm injection of inhibitor on the wellhead for 48 hours and then 20 ppm for another 48 hours to passivate the coupon. The inhibitor concentration was then reduced to 10 ppm continuously for maintenance of the protective film. This practice, which is common in the oil and gas industry, is used to form a protective layer that prevents acids from contacting steel. A dosage rate of 5–8 ppm was also tested for 2 weeks to optimize the dosage.

After 14 days of exposure, both the electrical resistance probe and the corrosion coupon exhibited the same carbon coating/protective layer that was further confirmed by Fourier-transform infrared (FTIR) spectroscopy and energy dispersive X-ray spectroscopy (EDS) (See Figure 3). The carbon coating has resulted from the corrosion inhibitor, which is an organic corrosion inhibitor.



ANALYSIS DETAIL

IR, As Dried		
Aliphatic hydrocarbons	Major	
Inorganics	Major	
SEM/EDS of Sample		
Carbon	48	%
Oxygen	15	%
Sulfur	8	%
Silicon	8	%
Iron	7	%
Copper	6	%
Aluminum	4	%
Nitrogen	2	%
Magnesium	1	%

Figure 3: EDS test on corrosion coupon indicates a major carbon as a passivation layer (left) and Probe inspection - the layer of inhibitor coating was observed and was partially peeled off by retrieval actions (right).

The correlation between Fe and corrosion rate is described below from brine analysis test results and corrosion meter data logger corrosion rate recorded in the accumulator outlet. The pH level was stable at approximately 2.67 with a pressure of 10.03–11.37 bar.

The dissolved Fe concentration at the accumulator outlet correlates well to a significant reduction in corrosion, measured in mils penetration per year (MPY), using the inhibitor (See Figure 4). Before the injection, both Fe and data logger/electrical resistance corrosion rates showed higher values. At 30 ppm for 72 hours, the corrosion rate from the electrical resistance data decreased 88%, from 16 to 1.9 MPY. The dose was then decreased to 20 ppm for 3 days with no change in total Fe. Low corrosion rates and Total Fe were maintained when the dose of inhibitor was reduced to 10 ppm. A slight increase in corrosion rate and Fe resulted (both increased approximately 20%) after reducing the dose to 5 ppm. Finally, the total Fe concentration decreased to 1.2 ppm and the electrical resistance corrosion rate decreased to 4 MPY when the dose of inhibitor was increased back to 10 ppm. These results suggest that a maintenance dose of 10 ppm of the inhibitor was optimal under these acidic conditions.

When the probe was removed, some of its protective coating was disturbed and peeled off (See Figure 3); hence, the increase of corrosion rate to 3.65 MPY after reaching equilibrium conditions for the stabilized electrical resistant metal loss reading. An optimization test also was conducted that reduced the injection dose to 5–8 ppm with a result of 6–8.5 MPY. This test demonstrated that the higher the injection rate rose, the lower the corrosion rate fell. The corrosion coupon results will be discussed in the next section.

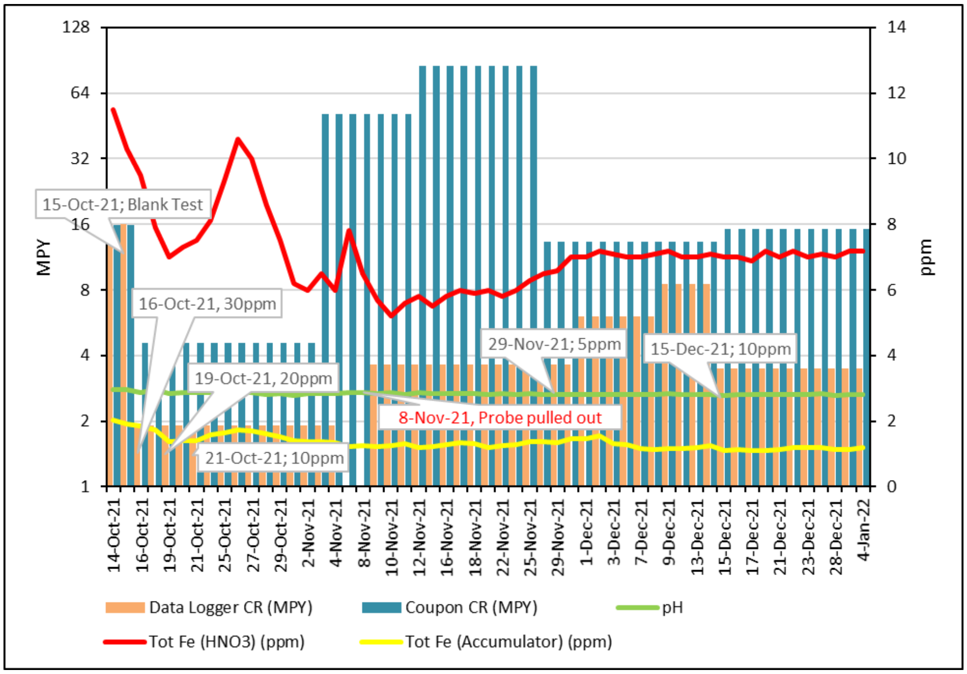


Figure 4: Total Fe, corrosion rate, and pH trends at accumulator outlet.

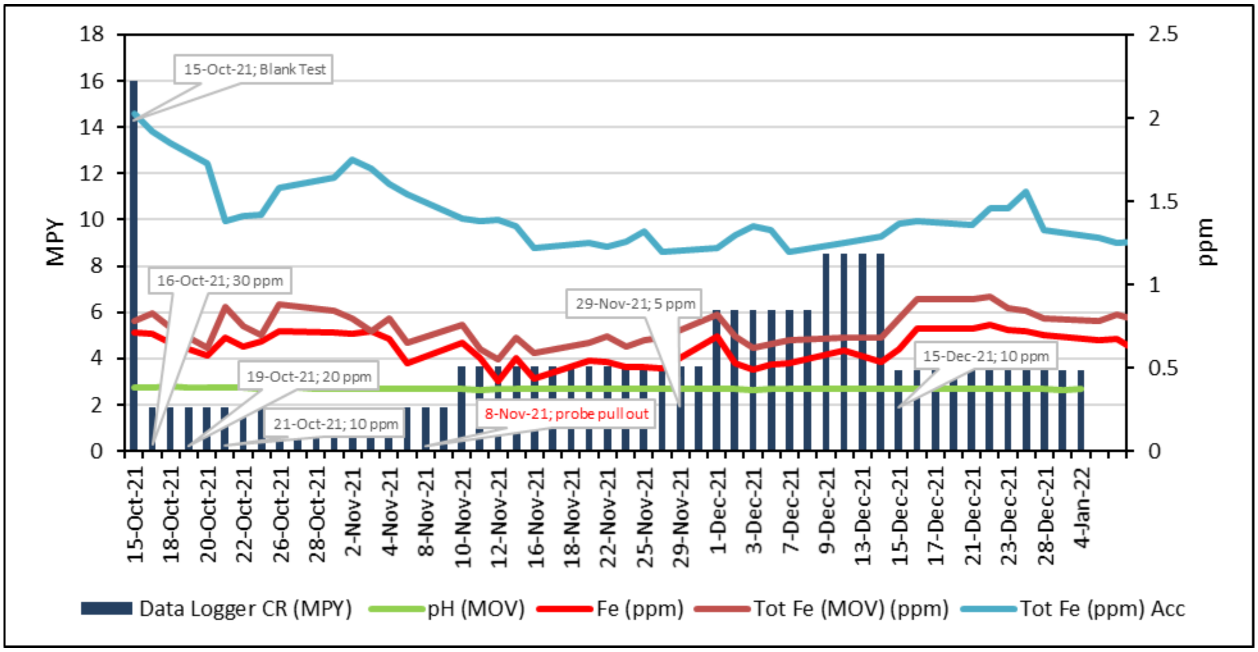


Figure 5: Fe concentration and corrosion rate comparison at the MOV sampling point.

The dissolved Fe concentration at the MOV has a Fe trend that is similar to the accumulator outlet (See Figure 5). This trend also demonstrates that increasing the dose of the inhibitor leads to a decreasing corrosion rate and a lower total Fe concentration.

4.2 Corrosion Rate Trend Comparison

The corrosion rate is divided into two trends. The first trend, from September through November, (See Figure 6) occurred before the electrical resistance probe was removed and the second trend, from November through January, occurred after the probe was removed. Whereas the first trend (See Table 1) consisted of the 1st blank test (from September 22 to September 25), caustic treatment, 2nd blank test (from October 4 to October 14), and initial passivation inhibitor treatment, the second trend (See Table 2) showed inhibitor injection with the equilibrium trend between 5 and 10 ppm.

4.2.1 The First Trend (Before The Probe Removal)

As shown in Figure 6, the metal loss trend during the 1st blank test period was steeply increasing, which resulted in the highest corrosion rate of 32.85 MPY. Afterward, during the caustic injection, the metal loss trend decreased to a corrosion rate of 10.04 MPY. The 2nd blank test also generated a rapid increase of metal loss with a corrosion rate of 15.93 MPY, which was less than the 1st blank test and similar to the coupon result. After the corrosion inhibitor dosage, the corrosion rate for the coupon was lowered to 4.58 MPY, a 71% reduction. The corrosion rate on the probe was lowered to 1.9 MPY, an 88% reduction.

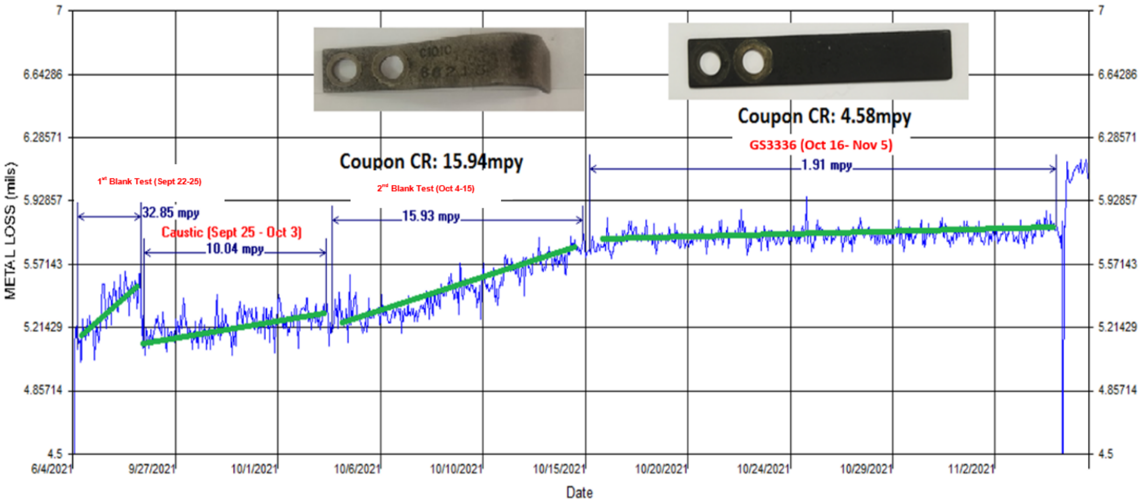


Figure 6: Probe and coupon corrosion rate comparison from September to November.

Table 1. Coupon and electrical resistance corrosion rates during the period from September to November

Treatment Regime (Period)	Electrical Resistance (MPY)	Corrosion Coupon (MPY)	Exposure Time (days)	Remarks
1st Blank Test (Sept 22–25)	32.85	-	-	Coupon not yet installed
Caustic (Sept 25–Oct 3)	10.04	-	-	Coupon not yet installed
2nd Blank Test (Oct 4–14)	15.93	15.94	18	-
GS3336 (Oct 15–Nov 5)	1.91	4.58	14	Passivation

In the coupon picture on the right, (See Figure 6), we can see a coating on the coupon. The coupon was exposed during inhibitor injection and subsequently developed a layer of coating. EDS testing showed a high amount of carbon in the coating, which is in agreement with the hydrocarbon film we found by FTIR (See Figure 3). The new corrosion inhibitor contains carbon-based corrosion inhibitors that form a protective film on metal surfaces.

The coupon data in the MOV (SP#3) is not displayed here because the high two-phase flow causes turbulent conditions that may yield excessively high corrosion rates due to aggressive erosion and cavitation effects on the coupons. Also, the material of the coupons, mild steel C1010, likely contributed to the higher corrosion rate.

4.2.2 The Second Trend (After The Probe Removal)

The metal loss trend during the 1st 10-ppm injection period, from November 3 until December 1, steadily decreased, which resulted in a reduction of corrosion rate from 4.26 to 3.65 MPY (See Figure 7). A 5–8 ppm dosage was also tested during the field evaluation to find the optimum inhibitor dosage. However, electrical resistance showed an 83% increase in corrosion rate compared with the 1st 10-ppm dosage. The last stage of treatment reverted to 10 ppm, which resulted in a corrosion rate of 3.48 MPY, a 48% decrease.

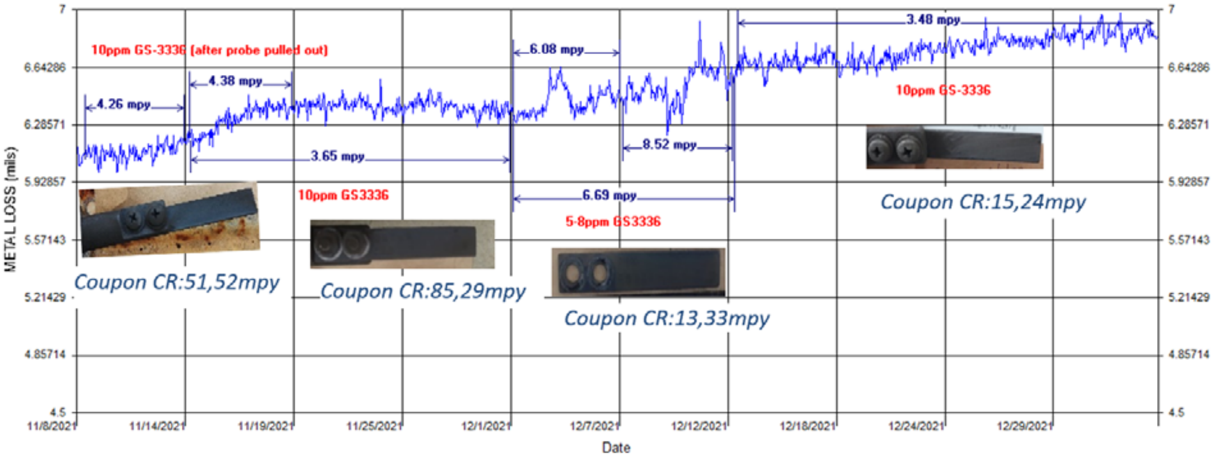


Figure 7: Electrical resistance and coupon corrosion rates from November to January.

The corrosion coupon of the second trend shows a higher corrosion rate compared with the electrical resistance results (See Table 2). The higher result rate is due to the shorter exposure time, only 7–14 days. Therefore, to get meaningful results, coupons must be exposed for monitoring for a minimum of 30 days to a maximum of 90 days. Note that the retrieval of the corrosion probe led to inconsistent quantitative readings, but the readings still showed a qualitative response in line with the coupon readings. Additionally, the subsequent coupons replaced were without the initial treatment step, that is without the hydrocarbon film coating on the surface of the coupon, which explains the higher corrosion rate of those coupons compared with the probe.

4.3 Delta Pressure and Flow

The pressure and flow throughput were recorded from the plant DCS (Distributed Control System) control room (See Figure 8). During the caustic regime between September 24 and October 5, before the commencing of the inhibitor, a decrease in flow trend occurred. The trend was confirmed by the increasing delta pressure, which was calculated from accumulator pressure data minus production well pressure data. The inhibitor treatment managed to stabilize the delta pressure from the beginning of the injection period until the end of the trial. The flow trend shows some spikes that possibly are due to faulty instrumentation.

Table 2. Coupon and ER corrosion rates during the period from November to January.

Treatment Regime (Period)	Electrical Resistance (MPY)	Corrosion Coupon (MPY)	Exposure Time (days)	Remarks
GS3336 (Nov 3–11)	4.26 (equilibrium undergoing)	51.52	8	10 ppm*
GS3336 (Nov 16–Dec 1)	3.65	85.29	14	10 ppm*
GS3336 (Dec 1–Dec 12)	6.69	13.33	18	Optimization at 5–8 ppm*
GS3336 (Dec 12–Jan 4)	3.48	15.25	18	10 ppm*
*without any initial treatment				

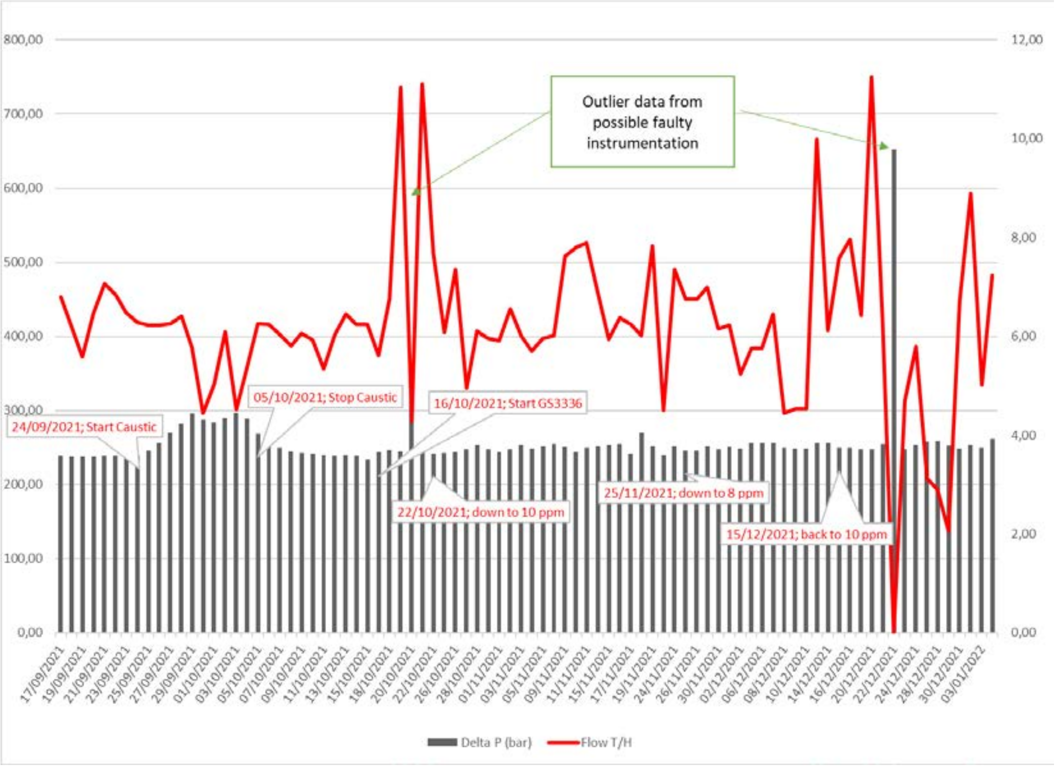


Figure 8: Delta pressure and flow trends.

5. Conclusions

Our conclusions from the field evaluation of the new GeoSol™ GS3336 corrosion inhibitor are summarized as follows.

- During the inhibitor treatment, scale deposition was not found on the electrical resistance probe or the corrosion coupons when they were retrieved for inspection. Instead, we observed that the probes and coupons were covered with a carbon coating/protective layer. FTIR and EDS lab tests and the flow and delta pressure data confirmed the presence of coatings.
- The inhibitor trial results showed not only a reduction in the corrosion rate, but also a mitigation, due to the use of caustic, of the ongoing plugging of the pipeline.
- The Fe results correlate well to a significant reduction in corrosion using the inhibitor. The higher corrosion rate from coupon weighing is due to the limited exposure time. However, the corrosion rate shows a decreasing trend during the end of the trial at a 10–ppm dosage.
- The most optimum dosage is 10 ppm, and the passivation/initial treatment with a higher concentration of inhibitor is required to provide better corrosion protection as per the observation of the corrosion rate with and without initial treatment.
- The corrosion rate results from SP#1 (two-phase line) does not represent the actual result. The high corrosion rate is attributed to erosion, not corrosion. Thin coupons are subjected to wear and tension/compression oscillations in this two-phase flow environment. Future implementation may include switching coupon metallurgies from C1010 to A53B and installing a coupon rack to minimize coupon erosion.

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