

Case Study—Calcium-Carbonate-Scale Inhibitor Performance Degradation Because of H₂S-Scavenger Injection in Semoga Field

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Summary

Semoga field is an oil field in the Rimau block, which is located in South Sumatra, Indonesia. There is also a nearby oil field, Kaji field, in this block. These fields experienced reservoir souring and suffered a history of calcium-carbonate (CaCO₃) scale cases before a proper scale-inhibition program was implemented. At the end of January 2011, there was a separation-system problem at free water knock-out (FWKO) #2 Semoga Station. FWKO outlet lines were dismantled for inspection purposes, and it was found that the oil-outlet line at the downstream of the level control valve (LCV) was clogged by deposits, leaving an inner diameter (ID) of only 0.5 in.

X-ray diffraction (XRD) and X-ray fluorescence (XRF) analyses confirm that the deposit is CaCO₃ scale, even though routine scale-coupon monitoring shows very low scale growth. There is a hydrogen sulfide (H₂S) scavenger Brand X injection at the downstream of the LCV on the FWKO #2, with a concentration of 11,050 ppm. The scale-inhibitor dosage in the water line on Semoga Station was only 9–10 ppm. Laboratory simulation shows that H₂S scavenger Brand X injection reduced the scale-inhibition percentage from 97.2 to 35.3%, with 9 ppm of scale inhibitor. Meanwhile, no deposits were found in the oil-outlet line at the downstream of the LCV at Kaji Station, which has the same H₂S-scavenger-injection point and dosage. The scale-inhibitor dosage in the water line at Kaji Station was 17.5–22 ppm. Laboratory simulation shows that 20 ppm of scale inhibitor resulted in a scale-inhibition percentage of 58%. Laboratory analysis shows that the scale-inhibition percentage increases linearly as the scale inhibitor increases under H₂S scavenger Brand X influence.

However, another laboratory test conducted using H₂S scavenger Brand Y shows that the scale-inhibition percentage will decrease with the increase of scale-inhibitor concentration, until it reaches the lowest value before increasing again with the increase of scale-inhibitor concentration. Thus, the scale-inhibitor performance under H₂S scavenger Brand Y influence behaves parabolically.

It is concluded that H₂S-scavenger injection increases system pH, resulting in the increase of scaling tendency. However, adding scale-inhibitor concentration is not always the answer to overcoming scale growth resulting from this effect. It is important to understand scale-inhibitor performance behavior on certain H₂S-scavenger brands before taking preventive measures. Scale-inhibitor performance might have a linear correlation between increasing concentration and scale-inhibition percentage, as shown by the behavior with H₂S scavenger Brand X, but it might also have a par-

abolic correlation, as shown by the behavior with H₂S scavenger Brand Y or even other correlation types. A proper understanding of scale-inhibitor behavior can prevent a production loss caused by the deposition of 8,190 barrels of oil.

Introduction

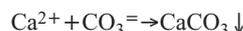
Semoga field is an oil field in the Rimau block, which is located in South Sumatra, Indonesia. There is also a nearby oil field in this block (i.e., Kaji field). All the fluid produced from these fields is gathered into three gathering stations—Kaji Station, Kaji Satellite, and Semoga Station. The fields had a history of CaCO₃ scale before proper scale inhibition using scale-inhibitor injection was implemented. Meanwhile, since the end of 2009, these fields have experienced reservoir souring, where H₂S is being generated from the reservoir and entering the system. To reduce the H₂S concentration in the facilities, H₂S scavenger is injected into the system.

At the end of January 2011, there was a separation-system problem at FWKO #2 Semoga Station, which was indicated by oil carry-over at the water line to Skimmer and an LCV failure at the oil line to normally closed. FWKO outlet lines were dismantled for inspection purposes, and it was found that the oil-outlet line at the downstream of the LCV was clogged by deposits, leaving an ID of only approximately 0.5 in. On the other hand, there was no deposition on the water-outlet line. Dismantling of FWKO #1 Semoga Station also resulted in no deposition in either the oil-outlet line or the water-outlet line. Benchmarking into the similar process system in Kaji Station resulted in no deposit being found after dismantling both the oil-outlet line and the water-outlet line of the FWKO there. Both stations have scale-inhibitor and H₂S-scavenger injection at similar points. The difference is that Kaji Station has a higher dosage of scale inhibition than Semoga Station.

This paper discusses the scale-inhibitor performance behavior when being injected in conjunction with H₂S-scavenger injection. An appropriate scale-inhibitor dosage will determine scale-inhibitor performance in inhibiting scale growth.

CaCO₃ Scale Deposition Influencing Factor

CaCO₃ scale buildup in oilfield facilities has been a problem for years in the wide-ranging area of the oil and gas industry, including in Kaji field and Semoga field. CaCO₃ scale deposition in production facilities, such as downhole tubing, pipeline, manifold, or produced-water line, will bring potential production loss because of severe flow restriction along the facilities and on uneven scale and may cause pitting corrosion beneath the scale, which leads to leakage of the facilities, requiring them to be shut down and replaced. CaCO₃ scale can be formed by a combination of calcium ion by either carbonate or bicarbonate ion, as follows (Patton 1977):



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The necessary components and conditions for CaCO₃ scale formation are often present in oilfield waters and their associated production systems. Dissolved calcium (Ca²⁺) and bicarbonate (HCO₃⁻) ions are already present in produced water in the Kaji field and the Semoga field. The concentration of the HCO₃⁻ is governed by the pH of the system (Sitz et al. 2003). There are four main factors influencing CaCO₃ scale buildup: partial pressure of CO₂, pH, temperature, and total dissolved salt. The lower the pH, the higher the solubility of CaCO₃, and the higher the pH, the lower the solubility of CaCO₃. In the higher pH, CaCO₃ will be in supersaturation condition and begin to crystallize. This process (the beginning of crystallization) is called nucleation, and it will be followed by crystal growth. The crystal grows, becoming larger over time, and begins to precipitate. With sufficient time and good adherence in surface, scale deposition will occur.

There are several solubility-calculation methods to predict the possibility of CaCO₃ scale deposition. The Stiff-Davis scaling-index (SI) calculation is the most-suitable method to calculate CaCO₃ scaling tendencies of oilfield brines (Davies and Scott 2006). The value obtained from this calculation indicates the degree of scaling tendency. A positive value means that there is CaCO₃-scaling tendency, while a value greater than one means that there is severe CaCO₃-scaling tendency. On the other hand, if the value is negative, the water is undersaturated with CaCO₃ and scale formation is unlikely. Planned action can be carried out to monitor scale growth immediately if calculation result shows a positive value. The Stiff-Davis SI can be calculated with Eq. 1 (Patton 1977), from which it is clear that water pH increase will increase SI, meaning the scaling tendency will increase linearly with pH increase.

$$SI = pH - K - pCa - pAlk, \dots\dots\dots (1)$$

where SI is the scaling index; pH is the actual pH of the water; and K is a constant, which is a function of salinity, composition, and water temperature. Values of K are obtained from graphical correlation with ionic strength and water temperature. pCa and pAlk represent the degree of alkalinity that can be obtained from calculation or graphical correlation, respectively.

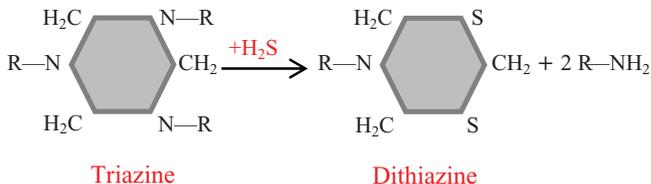
Scale buildup can be minimized by controlling the driving force of scale formation. One scale-controlling method is the use of scale inhibitor. Scale inhibitor is a chemical that will delay, reduce, or prevent scale formation when added in small amounts to a normally scaling water. Most scale inhibitors used in oilfields function by adsorbing onto the surface of crystals while they are still very tiny and just beginning to form (nucleation), preventing further growth. In some cases, scale inhibitor prevents the precipitated scale crystals from adhering to solid surfaces, such as piping or vessels (Patton 1977).

There are various types of scale monitoring for measuring scale growth in oilfield systems. One scale-monitoring system used widely to detect scale buildup is scale coupons. Scale coupons have a similar shape to corrosion coupons, except they are perforated with 6 to 8 holes. A scale coupon is placed in the system with the flat side facing the direction of flow. This causes turbulence and pressure drop inside the holes, which emphasizes any possibility of scale deposition. Scale growth can be calculated by taking the difference in the weight of the scale coupon before and after exposure for a certain period of time, after any hydrocarbon and impurities have been removed from the coupon. Scale-coupon monitoring is also used to monitor scale-inhibitor performance effectiveness (Patton 1977).

Triazine-Based H₂S Scavenger

H₂S has been a problem in Kaji field and Semoga field since 2009, with an average H₂S concentration of 200 ppm in system facilities. H₂S can be removed chemically by the direct injection of H₂S scavenger into the fluid stream. H₂S is normally removed from produced brine and gas in oilfield streams using amine aldehyde

condensates (triazine) (Davies and Scott 2006). This type of H₂S scavenger is also being used in Kaji field and Semoga field. Triazine works by quickly reacting with H₂S dissolved in triazine solution. To obtain the best result, there should be an adequate area and contact time between H₂S and triazine to react. The following equation is the reaction between triazine and H₂S:



Triazine-based H₂S scavenger has a very high pH to stabilize the triazine and prevent decomposition to formaldehyde, which would not be desirable in the bulk chemical. It also improves the solubility and reaction of the sulfide ions in the brine phase, therefore improving the efficiency of the scavenging process (Williams et al. 2010). So despite being very effective in removing H₂S, triazine-based H₂S scavenger has the side effect of increasing pH in the system in which it is being injected. It increases the possibility of scaling deposition in the system, because CaCO₃ solubility decreases with pH increase.

Chemical-Injection System in Kaji field and Semoga field

Kaji field and Semoga field have approximately 230 production wells, most of which have 90% water cut. All the produced water in Kaji field and Semoga field has a Stiff-Davis SI of more than one, which means they have severe scaling tendency. Ninety-two wells are being lifted artificially by a gas-lift-injection system. The scale-inhibition treatment applied in these fields is using scale-inhibitor injection through a gas-lift system. Scale inhibitor is injected through the gas-lift system using an atomizer to ensure the scale inhibitor is in tiny droplets, thus allowing it to be carried by the gas lift into the downhole. The scale inhibitor will mix with the producing fluid in the downhole, dissolve in the produced water, and reproduce in the producing fluid to the producing facilities. The scale-inhibitor concentration in the Kaji field is within the 17.5 to 22 ppm range, while in the Semoga field, it is 9–10 ppm. Many scale coupons have been installed in production lines to monitor the scale-inhibitor performance. Routine scale-coupon monitoring shows that the scale growth in both Kaji field and Semoga field is less than 1 gr/in.²/yr, which means that the scale inhibitor works satisfactorily.

Many producing wells in the Kaji field and the Semoga field also have H₂S. Producing fluid from the wells is gathered in the gathering stations. The H₂S concentration in the Kaji Station and the Semoga Station is 200 ppm on average. To reduce the H₂S concentration to an acceptable limit in the liquid system, H₂S scavenger is injected into an oil-outlet FWKO in both the Kaji Station and the Semoga Station. The H₂S scavenger injected was Brand X, but after the contract purchase of Brand X expires, Brand Y will be used.

When the separation-system problem occurred in Semoga Station at the end of January 2011, the first action was to optimize the separation system by adjusting the control valve at FWKO #2 Semoga Station. However, it has failed to give a satisfactory result. Further investigation led to the dismantling of the oil-outlet line FWKO #2 Semoga Station. It was found that the oil-outlet line at the downstream of the LCV was clogged by deposit, leaving only 6.25% of the total sectional area of the pipe or 0.5-in. of the original 6-in. pipe ID. There is H₂S scavenger Brand X injection at the downstream of the LCV on FWKO #2, with a concentration of 11,050 ppm. Fig. 1 shows the location where the deposit was found. The oil-outlet line of the FWKO in the Kaji Station was also dismantled, but there was no deposit, even though it has the same H₂S-

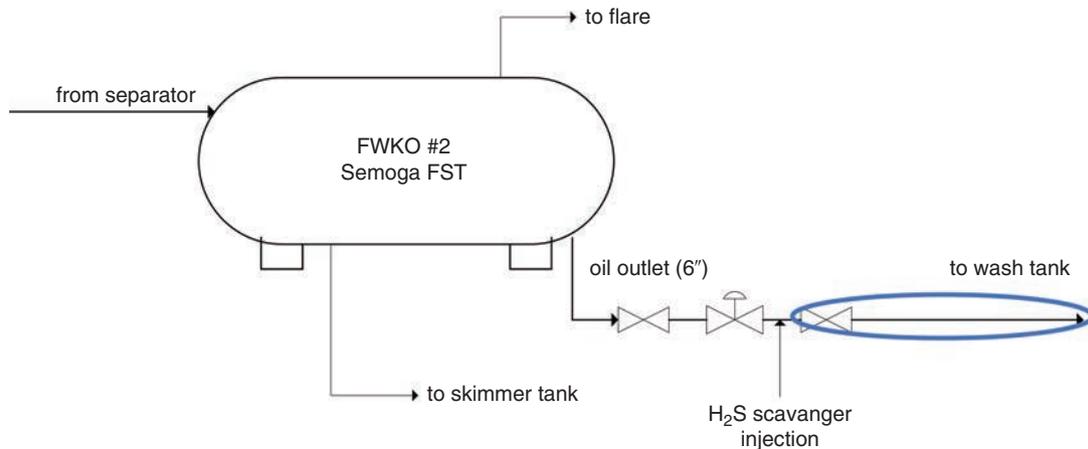


Fig. 1—Location of deposit found in FWKO #2 Semoga field station (marked with blue color).

scavenger injection point and dosage. The scale-inhibitor dosage in the water line in Kaji Station was within the 17.5 to 22 ppm range, while in the Semoga Station, it was only 9–10 ppm. This incident has caused a preventable production loss of 8,190 barrels of oil

Methodology

Laboratory Analysis To Identify Deposits. The deposit was identified using two methods, one method being solubility analysis and the other method being XRD and XRF analysis. Solubility analysis consisted of using two types of solvent: toluene and 32% hydrochloric acid (HCl). Toluene dissolves any hydrocarbon matter, while 32% HCl dissolves inorganic minerals, such as CaCO_3 and corrosion products. The deposit was immersed in 100 mL toluene in a glass beaker and stirred for a few minutes. The remaining deposit was lifted from the solution and dried. Afterward, the deposit was immersed in 100 mL of 32% HCl and left to react. This method gives qualitative results only.

The quantitative result of deposit identification was conducted by XRD and XRF analysis. Bulk crystallized compounds of the deposit can be analyzed by XRD for compound composition, and the compounds that are not crystallized well can be analyzed for elemental composition by XRF (Craig 2005). Combining these two analysis methods will give approximate quantitative composition of the compounds in the deposit.

Laboratory Analysis To Measure Scale-Inhibition Percentage

The laboratory analysis to measure scale-inhibition percentage is based on National Association of Corrosion Engineers (NACE) *Standard TM0374-2007* laboratory screening test to determine the ability of scale inhibitors to prevent the precipitation of calcium sulfate and CaCO_3 from the solution (for oil- and gas-production systems) with customization to account for H_2S -scavenger effect. The synthetic brine used in the analysis had the actual water chemistry of the produced water in the field, instead of the water composition provided in NACE *Standard TM0374-2007*. The blank solution used was the synthetic brine with the actual water chemistry of the produced water in the field and without any scale inhibitor or H_2S scavenger. The Ca^{2+} concentration of the blank solution was determined before and after precipitation. The precipitation procedure was conducted by immersing the blank test cell to 75% of its length in a water bath at $71 \pm 1^\circ\text{C}$ ($160 \pm 1^\circ\text{F}$) for 24 hours. After the 24-hour exposure, the test cell was removed from the water bath carefully to avoid any agitation. The test cell was allowed to cool to $25 \pm 5^\circ\text{C}$ ($77 \pm 9^\circ\text{F}$) for a time not to exceed two hours. When measuring Ca^{2+} after precipitation, it must be ensured that the CaCO_3 crystal stays at the bottom of the test cell and, thus, not be included in the measurement.

The analysis was conducted on two sets of simulation, one for H_2S scavenger Brand X and the other for H_2S scavenger Brand Y. For the first simulation set, two test cells of synthetic brine and 12 ppm of scale inhibitor were prepared and then 11,050 ppm of H_2S scavenger Brand X was added to one of the test cells. This simulation was to measure the decrease of scale-inhibition percentage in the Semoga Station water system in the presence of H_2S scavenger Brand X. Another two test cells of synthetic brine and 20 ppm of scale inhibitor were prepared. One of the test cells was given an addition of 11,050 ppm of H_2S scavenger Brand X. This simulation was to determine the scale-inhibition-percentage value that has been able to prevent scale growth in FWKO Kaji Station, even with H_2S scavenger Brand X injection. Another test cell of synthetic brine and 9 ppm of scale inhibitor was prepared and 11,050 ppm of H_2S scavenger Brand X was added to the test cell to determine the scale-inhibition-percentage value in outlet-oil line FWKO #2 Semoga Station. The second simulation was conducted to determine the scale-inhibitor performance behavior with H_2S scavenger Brand Y injection, because this brand will be used after the contract purchase of Brand X has expired. Three test cells with synthetic brine and 9 ppm of scale inhibitor were prepared to simulate the scale-inhibitor concentration in the Semoga Station water system. No H_2S scavenger was added on the first test cell, while the second cell was given an addition of 680.5 ppm of H_2S scavenger Brand Y and the third test cell was given an addition of 1,361 ppm of H_2S scavenger Brand Y. The two values of H_2S scavenger Brand Y addition were conducted to cover the fluctuation range of H_2S scavenger Brand Y injection in the station.

Another three test cells with synthetic brine and 11.5 ppm of scale inhibitor were prepared to simulate the scale-inhibitor concentration in the Kaji Station water system. No H_2S scavenger was added on the first test cell, while the second cell had an addition of 1,191 ppm of H_2S scavenger Brand Y and the third test cell had an addition of 2,381 ppm of H_2S scavenger Brand Y. These analyses were performed to simulate the lower range of scale-inhibitor injection in Kaji Station with the range of H_2S scavenger injection fluctuation. To simulate the higher range of scale-inhibitor injection in Kaji Station, another three test cells with synthetic brine and 17.5 ppm of scale inhibitor were prepared. Just like the previous analysis, no H_2S scavenger was added on the first test cell, while the second test cell had an addition of 1,191 ppm of H_2S scavenger Brand Y and the third test cell had an addition of 2,381 ppm of H_2S scavenger Brand Y.

Another set of simulations was conducted to ensure scale-inhibitor performance under a variety of scale-inhibitor concentrations and a uniform H_2S scavenger Brand Y concentration. The first test cell consisted of 20 ppm of scale inhibitor without H_2S scavenger

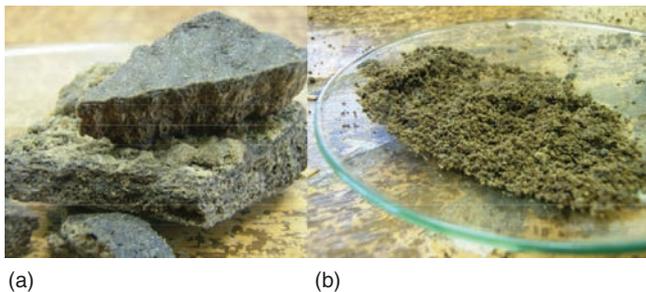


Fig. 2—Deposits found in FWKO #2 Semoga field station: (a) hard deposit and (b) brittle and loose deposit.

addition, while the second test cell had the same scale-inhibitor concentration but with an additional 2,530 ppm of H₂S scavenger Brand Y. The third test cell had a scale-inhibitor concentration of 40 ppm and the same H₂S scavenger Brand Y concentration, while the fourth test cell had a scale-inhibitor concentration of 50 ppm instead. Ca²⁺ concentration of all the solutions was measured after the precipitation procedure. The measured Ca²⁺ was used to calculate scale-inhibition percentage by using the following equation:

$$\% \text{Inhibition} = \frac{C_a - C_b}{C_c - C_h} \times 100 \%, \dots\dots\dots (2)$$

where C_a is the Ca²⁺ concentration in the treated sample after precipitation, C_b is the Ca²⁺ concentration in the blank after precipitation, and C_c is the Ca²⁺ concentration in the blank before precipitation.

Data and Analysis

Deposit Identification. The color of the deposit found is brownish-black with a hydrocarbon odor. By visual inspection, it is determined that there are two kinds of deposit: one is the hard deposit, similar to normal CaCO₃ scale, while the other is brittle and loose. The hard deposit has layers such as typical CaCO₃ scale, which is formed continuously over time. These two deposits are shown in Fig. 2.

Solubility analysis proves that the deposit is not hydrocarbon-based, because no reaction occurred during immersion in toluene. On the other hand, there was a strong reaction when the deposit was immersed in 32% HCl, resulting in vigorous bubbles and a brownish-black mass. The 32% HCl is a strong acid, which dissolves inorganic minerals such as CaCO₃ and corrosion product. The bubbles indicate the reaction between inorganic minerals and the corrosion product, while the brownish-black mass indicates the hydrocarbon-based deposit, which did not react with the HCl. Fig. 3 shows the result of this immersion test.

Because the immersion test gives a qualitative result, XRD and XRF analyses were conducted at a certified laboratory to find the

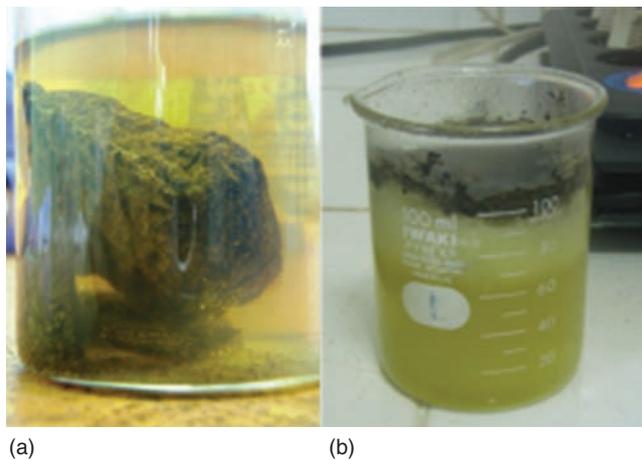


Fig. 3—Solubility test on deposit: (a) in toluene and (b) in 32% HCl.

quantitative deposit identification. Table 1 shows the XRD result, while Table 2 shows the XRF result. XRD analysis confirms that the mineral in the deposit is calcite, which is a carbonate mineral. XRF analysis shows that calcium accounts for 55.64% of the chemical composition of the deposit, which is the major component in the deposit. The second major component is magnesium, which accounts for 16.63% of the deposit. These results confirm that the deposit is CaCO₃, which is the type of scale found in the Rimau block.

Scale-Inhibitor Performance. The scale inhibitor behaves differently when there is H₂S-scavenger injection as compared with no injection. The scale inhibitor also behaves differently depending on the H₂S-scavenger brand, as will be discussed in more detail in the following subsections.

Under the Influence of H₂S Scavenger Brand X. Table 3 shows the laboratory result for the scale-inhibition percentage for H₂S scavenger Brand X. System A, which is a 12-ppm scale inhibitor, represents the normal condition of scale-inhibitor performance in the system without any H₂S-scavenger injection. On the other hand, System B, which comprises 12-ppm scale inhibitor and 11,050-ppm H₂S scavenger Brand X, represents the scale-inhibitor performance in the system with H₂S-scavenger injection. The scale-inhibition percentage dropped from 97.2 to 35.2%, which means that the scale-inhibitor performance is degrading approximately 63.5% under H₂S scavenger Brand X influence when the scale-inhibitor dosage is 12 ppm. Meanwhile, System C simulates the stream in the system of Kaji Station, in which the scale-inhibitor dosage is 20 ppm without H₂S-scavenger injection. The scale-inhibition percentage for System C is 90.8%, lower than the scale-inhibition percentage on Semoga Station, as represented by System A. However, when the scale-inhibition percentage at the oil-outlet FWKO Kaji Station (where no deposition occurred) was simulated by System

Depth (m)	Clay Minerals (%)				Carbonate Minerals (%)			Other Minerals (%)				Total (%)			
	Smectite	Illite	Kaolinite	Chlorite	Calcite	Magnesian	Dolomite	Siderite	Quartz	K - Felds	Plagioclase	Pyrite	Clay	Carbonate	Other
-	-	-	-	-	100	-	0	0	-	-	-	-	100	0	

TABLE 2—DEPOSIT ANALYSIS USING XRF

Element	Result (%wt)
Antimony, Sb	0.002
Tin, Sn	<0.001
Cadmium, Cd	0.06
Paladium, Pd	<0.002
Silver, Ag	0.05
Barium, Ba	5.170
Molybdenum, Mo	0.001
Niobium, Nb	<0.001
Zirconium, Zr	<0.001
Strontium, Sr	7.115
Rubidium, Rb	<0.0002
Bismuth, Bi	<0.002
Arsenic, As	0.0047
Selenium, Se	<0.0003
Platinum, Pt	<0.002
Lead, Pb	0.305
Tungsten, W	<0.002
Zinc, Zn	0.188
Copper, Cu	0.025
Nickel, Ni	0.032
Cobalt, Co	<0.001
Iron, Fe	4.856
Manganese, Mn	0.179
Chromium, Cr	<0.002
Vanadium, V	0.001
Titanium, Ti	<0.001
Calcium, Ca	55.641
Kalium, K	0.190
Sodium, Na	6.590
Silica, Si	0.419
Aluminum, Al	0.181
Magnesium, Mg	16.631
Sulphur, S	1.604

D, which comprises 20-ppm scale inhibitor and 11,050-ppm H₂S scavenger Brand X, the scale-inhibition percentage becomes 58%. The scale-inhibitor performance is degrading 36% under the H₂S-scavenger influence when the scale-inhibitor dosage is 20 ppm. The scale-inhibition percentage in System D is lower than expected, yet it means that with only 58% scale inhibition in the laboratory simulation, there will be no scale deposition in the actual system in the field.

System E simulates the stream in oil-outlet FWKO #2 Semoga Station, which comprises 9-ppm scale inhibitor and 11,050-ppm

H₂S scavenger Brand X. The scale-inhibition percentage is only 1.8%, which means that the scale inhibitor does nothing to inhibit the scale growth in the oil-outlet FWKO #2 Semoga Station. Therefore, the scale was deposited along the line severely.

The analyses show that scale-inhibitor performance is degrading with the higher scale-inhibitor concentration when there is no H₂S-scavenger injection. The scale-inhibitor performance will degrade under the influence of H₂S-scavenger injection, but the performance-degradation percentage is less if the scale-inhibitor dosage is higher. Scale-inhibitor performance with H₂S scavenger Brand X injection increases with the increasing scale-inhibitor concentration. This is contrary to its behavior when there is no H₂S-scavenger injection.

Under the Influence of H₂S Scavenger Brand Y. When the same testing procedure was carried out on H₂S scavenger Brand Y, different results were obtained. **Table 4** shows the laboratory-analysis results on the scale-inhibition percentage under a variety of scale-inhibitor and H₂S-scavenger dosages. Systems F, I, L, and O show the scale-inhibition percentage of 9 ppm, 11.5 ppm, 17.5 ppm, and 20 ppm of scale inhibitor, respectively. The laboratory analysis shows that 9 ppm of scale inhibitor gives a greater scale-inhibition percentage, while 20 ppm of scale inhibitor is the lowest among the four systems. The analyses once again show that scale-inhibitor performance is degrading with the higher scale-inhibitor concentration when there is no H₂S-scavenger injection.

Systems F, G, and H have 0 ppm, 680.5 ppm, and 1,361 ppm of H₂S scavenger, respectively, with 9 ppm of scale inhibitor. As predicted, the scale-inhibition percentage decreases with the increase of H₂S-scavenger concentration. This result is also shown on Systems I, J, and K, which have 0 ppm, 1,191, and 2,381 ppm of H₂S scavenger and 11.5 ppm of scale inhibitor, respectively. And also with Systems L, M, and N, which have 17.5 ppm of scale inhibitor with the same H₂S-scavenger concentration as Systems I, J, and K. The scale-inhibition percentage is degrading 6.65% with the addition of 1,191 ppm of H₂S scavenger when the scale-inhibitor concentration is 11.5 ppm, as shown by System J. Meanwhile, System M shows that the scale-inhibition percentage is only decreasing 5% when the scale inhibitor is 17.5 ppm. System K shows that the scale-inhibition percentage is degrading 13.3% with the addition of 2,381 ppm of H₂S scavenger when the scale-inhibitor concentration is 11.5 ppm, while it is only decreasing 12.45% when the scale inhibitor is 17.5 ppm, as shown by System N. The larger concentration of scale inhibitor resulted in a lower-percentage degradation of scale-inhibition percentage under the same H₂S-scavenger concentration.

System P, which has 20 ppm of scale inhibitor with 2,530 ppm of H₂S-scavenger concentration, resulted in a scale-inhibition percentage of 60.7%. When the scale-inhibitor concentration is increased to 40 ppm and 50 ppm, as simulated by system Q and R, respectively, the scale-inhibition percentage increases to 82.1% and 95.4%. Systems P, Q, and R show that higher scale-inhibitor concentration with the same H₂S-scavenger concentration will give higher scale-inhibition percentage.

TABLE 3—SCALE-INHIBITION PERCENTAGE FOR SCALE INHIBITOR UNDER H₂S BRAND X INFLUENCE

System Code	Scale Inhibitor (ppm)	H ₂ S Scavenger (ppm)	Percentage Scale Inhibition
A	12	0	97.2
B	12	11,050	35.2
C	20	0	90.8
D	20	11,050	58
E	9	11,050	1.8

TABLE 4—SCALE-INHIBITION PERCENTAGE FOR SCALE INHIBITOR UNDER H₂S BRAND Y INFLUENCE

System Code	Scale Inhibitor (ppm)	H ₂ S Scavenger (ppm)	Percentage Scale Inhibition
F	9	0	99.3
G	9	680.5	97.7
H	9	1,361	96.2
I	11.5	0	97.8
J	11.5	1,191	91.3
K	11.5	2,381	84.8
L	17.5	0	92.4
M	17.5	1,191	87.7
N	17.5	2,381	80.9
O	20	0	90.8
P	20	2,530	60.7
Q	40	2,530	82.1
R	50	2,530	95.4

However, upon closer observation of the scale-inhibition percentage on Systems K, N, P, Q, and R, which all have approximate H₂S-scavenger concentration (2,381 ppm on Systems K and N and 2,530 ppm on Systems P, Q, and R), there is different scale-inhibitor performance behavior. System K has 9 ppm of scale inhibitor, and its scale-inhibition percentage is 84.8%. System N has 11.5 ppm of scale inhibitor, and its scale-inhibition percentage is 80.9%. System P has 20 ppm of scale inhibitor, and its scale-inhibition percentage is 60.7%. These results show that the scale-inhibition percentage is degrading with the increase of scale-inhibitor concentration. However, when the scale-inhibitor concentration is increased to 40 ppm, as in System Q, then the scale-inhibition percentage increases to 82.1%. And with an even higher scale-inhibitor concentration of 50 ppm, as in System R, the scale-inhibition percentage becomes 95.4%. These results show that the scale-inhibition percentage will decrease with the increase of scale-inhibitor concentration until it reaches the lowest value before increasing again with the increase of scale-inhibitor concentration. Thus, the scale-inhibitor performance in a system with H₂S scavenger Brand Y injection behaves parabolically.

Conclusion

H₂S-scavenger injection will affect scale-inhibitor performance because it will degrade the scale-inhibition percentage compared with the system without H₂S-scavenger injection. In maintaining the scale-inhibitor performance to prevent scale growth, increasing scale-inhibitor dosage is not always the answer. It is important to understand that scale-inhibitor performance behavior on a certain H₂S-scavenger brand before taking preventive measures. Scale-inhibitor performance might have a linear correlation between increasing concentration and scale-inhibition percentage, as shown by the behavior with H₂S scavenger Brand X, but it might also have a parabolic correlation, as shown by the behavior with H₂S scavenger Brand Y or even another correlation type.

Proper understanding of scale-inhibitor behavior under certain H₂S-scavenger-brand injection is necessary to avoid loss in production caused by scale-deposition issues. By applying the appropriate scale-inhibitor concentration on an H₂S-scavenger-influenced system, the production loss of 8,190 barrels of oil in Semoga Station could have been prevented.

Nomenclature

C_a = Ca²⁺ concentration in the treated sample after precipitation
 C_b = Ca²⁺ concentration in the blank after precipitation

C_c = Ca²⁺ concentration in the blank before precipitation

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