JIP investigates: What really happens to high-strength drill pipe after exposure to sour gas environment?

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SOUR GAS AND high-strength steel are generally accepted to be incompatible. However, when drilling beyond 20,000 ft, S135 and higher steel grades become necessary to support their own weight, and due to the elevated downhole pressures in the range of 15-20 ksi, even minimal concentrations of H₂S result in partial pressures that are considered hostile for these steel grades.

This article presents initial results from a joint industry project exposing S-grade drill pipe samples to various H₂S concentrations in temperature ranges from 70-170°C and exposure times of 1-3 hr, representing typical conditions when circulating a gas kick to surface. Test conditions have been designed to closely recreate actual downhole conditions. After exposure to the sour environment, the samples have been taken to fatigue testing to evaluate actual damage against undamaged base-line fatigue results.

INTRODUCTION

Sour drilling environments where H₂S gas is present and sour-gas kicks are possible can lead to sulfide stress cracking (SSC) failures in steel drill pipe. In practice, a combination of stress, an environment containing H₂S and a susceptible material are required for SSC to occur. SSC occurs as a result of atomic hydrogen entering the steel. Once inside the metal, the atomic hydrogen diffuses to initiation sites, where it can cause localized increases in stress or a reduction in the strength of the material lattice.

It is generally agreed that brittle H₂S-induced cracking is closely related to hydrogen embrittlement as a result of the ingress of hydrogen into the stressed material. Hydrogen is a problem in most steels because it is highly mobile in atomic form and can both diffuse through and be transported by the movements of dislocations. Hydrogen embrittlement can result in either a loss of ductility or a cracking phenomenon. Conditions that promote SSC in drill pipe include high tensile stress, high concentrations of H₂S, low pH, high pressure, high chloride content, lower temperatures and high material hardness (higher-strength steels generally have higher hardness properties).

Material selection for drill pipe in sour applications is significantly more complex than material selection for production casing and tubing in similar well applications due to:

- A more closely controlled and known environment by the time casing and especially tubing strings are run.
- The defined requirement for these strings to survive long-term exposure to corrosive atmosphere whereas drill strings will only be exposed for a short time during a loss of hydrostatic equilibrium in the well.

Production casing and tubing designers determine if the well parameters create a sour service environment as defined by NACE MR0175. Production casing and tubing materials resistant to SSC are required if the system contains water as a liquid, the H₂S partial pressure exceeds 0.05 psi and the system pressure is greater than or equal to 65 psi or 265 psi, depending on the gas-to-oil ratio of the system.

H₂S partial pressure is calculated as:

\[ ppH₂S = P \times MFH₂S \]

where \( ppH₂S \) is the \( H₂S \) partial pressure (psi), \( P \) is the total system pressure (psi), and \( MFH₂S \) is the mol fraction of \( H₂S \).

Over the last five years, due to the increase in oil prices, the industry has seen a re-emergence of deep and ultra-deep drilling projects that have again become economically feasible. At the elevated downhole pressures characterizing these projects, even traces of hydrogen sulfide will result in SSC hazards. If the production casing or tubing designer determines that materials resistant to SSC are required, NACE MR0175 guidelines and tables provide guidance for selecting materials that can be used with confidence.

The situation is somewhat different for the drillstring designer. Per NACE MR0175, API drill pipe material grades E-75, X-95, G-105 and S-135 are all acceptable if SSC is avoided by controlling the drilling environment. NACE MR0175 adds: “As service stresses and material hardness increase, drilling fluid control becomes increasingly important.” Implementing the following practices can help control the drilling environment:

- Maintain the drilling fluid density to minimize formation fluid influx.
- Neutralize H₂S in the formation fluids by maintaining a mud pH of 10 or higher.
• Utilize sulfide chemical scavengers and/or corrosion inhibitors.

• Use oil-base drilling fluids.

The document doesn’t address situations where the H$_2$S concentration and partial pressure are at levels above where drilling fluid control can be considered reliable, and underbalanced drilling (UBD) situations where the drill string can have direct exposure to H$_2$S gas for extended periods of time.

In addition, a drillstring assembly incorporates a tool joint that is typically manufactured from a forging and a friction weld that attaches it to the upset of the pipe body. These additional areas of the drill pipe assembly must be considered to provide reliable operation in critical sour drilling applications. Operating companies often have internal policies to deal with high-concentration H$_2$S gas wells, such as limiting the drillstring material to G-105 or lower-strength grades combined with the environmental control steps outlined in MR0175 and/or using oil-base drilling fluids when possible.

In steel drill pipe manufactured according to API specifications, the self-supporting length (i.e., the maximum well depth that can be reached with a certain diameter/weight/grade combination before the string will reach its yield due its own weight) limits the applicability of materials that are generally accepted as being H$_2$S-compatible to a maximum string length of about 5,500 m (Figure 1). Critical applications such as deepwater, extended-reach or ultra-deep drilling often require high-strength drill pipe (API grade S-135 and higher) to accommodate the high torsional and axial tension loads encountered in these wells. In these cases, drilling engineers cannot use G-105 or other similar strength sour service drill pipe grades because they provide insufficient torsional strength and/or inadequate axial tension capacity.

When using high-strength drill pipe in sour applications, controlling the drilling environment as discussed above becomes vitally important. Even with extreme care and cautious operating procedures, direct, short-term exposure to H$_2$S can occur. What are the consequences of such H$_2$S exposure events? And can drilling engineers determine the risks associated with sour gas kicks while drilling with high-strength drill pipe?

Please note that API G-105 grade is not resistant to SSC. However, operators have successfully used G-105 in sour applications with appropriate drilling environmental controls. At the same time, it is important to recognize that documented SSC failures of G-105 drill pipe have occurred. There are SSC-resistant drill pipe material grades with specified minimum yield strengths up to 105,000 psi that have generally provided excellent performance in sour applications, including areas with high H$_2$S concentrations. As a point of clarification, drill pipe material grades with specified minimum yield strengths in the range of 95,000 psi to 105,000 psi are often referred to as high-strength steels.

This article is focused on S-135 material with specified minimum yield strengths of 135,000 psi, and the "high strength" designation mentioned in the headline and throughout this article refers to S-135 grade drill pipe. Since some critical sour applications utilize S-135 drill pipe, a
study was conducted to investigate the possible consequences of unintended short-term H₂S exposure to this high-strength material.

Of course, all S-135 drill pipe is not the same. Significant variations in chemical composition and material properties, including yield and tensile strength, hardness, toughness, Charpy impact properties, resistance to crack initiation and propagation, etc., can have a major impact on the material’s performance in mildly sour applications. This initial study did not attempt to control the myriad possible combination of properties that might impact S-135 performance. Instead, the investigation considered the effect on typical, available S-135 drill pipe.

In addition, it is important to recognize that no high-strength steel drill pipe grades with specified minimum yield strengths of 135,000 psi and above are resistant to SSC in environments containing H₂S. S-135 drill pipe has been safely used to drill mildly sour applications in many regions of the world by controlling the drilling environment and minimizing direct H₂S exposure. S-135 drill pipe should not be used to drill in applications with significant concentrations of H₂S or where prolonged direct exposure to even relatively low concentrations of H₂S is possible, such as under-balanced drilling of sour wells.

**PROJECT SCOPE**

When drilling to more than 5,000 m, operators are typically forced to go to higher-strength drill pipe grades to satisfy the demand for adequate hydraulics, translated into larger string diameters. The desire to land the well in the reservoir with 8 ¾-in. diameter to still retain a workable contingency size, as well as running adequately sized production systems for high-rate gas wells, dictates a 5-in. or bigger drill string, even in the lower section of the well. This commonly results in 6 ¾-in. top hole drill pipe sections.

The dilemma that no really SSC-resistant drill pipe materials exist on the market for the strength levels required by these designs requires the operator to drill these wells sometimes severely overbalanced to ensure that no significant formation fluid volumes enter the wellbore while drilling, i.e., that the “drilled gas” can be neutralized by the high mud pH and the scavengers present in the drilling fluid system. Especially on production wells, due to the generally low permeabilities of those deep gas

<table>
<thead>
<tr>
<th>Influence Factor</th>
<th>Minimum</th>
<th>Maximum</th>
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<tr>
<td>Drill pipe materials</td>
<td>G105</td>
<td>S135</td>
</tr>
<tr>
<td>H₂S partial pressure</td>
<td>0.006 bar</td>
<td>6 bar</td>
</tr>
<tr>
<td>Ambient temperature</td>
<td>70°C</td>
<td>150°C</td>
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<tr>
<td>Exposure time</td>
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<td>3 hours</td>
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**Figure 4:** A matrix of test conditions was defined at the beginning of the project, considering the factors that generally promote the occurrence of SSC.
reservoirs, the high overbalance conflicts with production requirements of low invasion, damage and drilling skins.

Due to the requirement to develop a deep sour gas field (>2% H₂S at reservoir depths of 5,500-6,000 m), it was decided to investigate the actual damage that high-strength drill pipe (S135 grade) will suffer when exposed to these formation fluids over a short time (1-3 hr), as it would be typical for circulating out the kick during a well-kill operation.

During drilling, the drillpipe string is operating in the mud, a highly alkaline environment with pH values around 10 -11. As the probability for the initiation of cracks is influenced by the pH value of the fluid, in such high-alkaline systems, the time to failure can become very long (Figure 2). The probability for the generation of cracks therefore is very low.

According to NACE MR0175 (Figure 3), the pH value has a main influence on sulfide stress corrosion cracking. It can be seen that test solutions with high pH values are ranked as non-sour service applications. For the qualification of materials for sour service application, standard corrosion tests as defined by NACE TM 0177 are performed where the test solutions are conditioned to very low pH values. It is evident that such standard NACE test solutions do not reflect the real fluid environment as it is present downhole.

The following factors generally promote the occurrence of SSC: H₂S partial pressure, tensile load, low temperatures (the higher the temperature, the higher the permissible material tensile yield for SSC resistance), and exposure time. With that in mind, the matrix (Figure 4) of test conditions was defined at the beginning of the project.

Because of the short exposure, it was decided not to use the NACE test standard with a constant tensile load over a long period of time but rather to re-create the downhole fatigue environment for a 5-in. drillstring that is rotating in a 4 3/4" 30 m dogleg. The bending geometry results in a fatigue amplitude of +/- 10% around a base tensile load.

For the initial test series, a base load of 90% of the tensile yield (121.5 ksi) was selected, as the worst-possible conditions should be re-created. Samples were manufactured from a joint of pre-fatigued 5-in. S135 drill pipe according to a standardized fatigue-test sample design and as a baseline, a first sample series was sent through the fatigue test without prior H₂S exposure.

The test procedure was defined as inserting the machined samples into an autoclave half-filled with an H₂S-saturated, 5% K₂CO₃ solution in water to represent the potassium carbonate mud system downhole. The other (top) half of the autoclave was filled with the test gas mixture, and the sample was subjected to 90% of its yield strength. This whole assembly was then rolled for 3 hr at an ambient temperature of 70°C to represent the constant wetting of the metal surface during circulating the kick past it. At the end of the 3-hr test, the autoclave was purged of the test gas, and the H₂S-saturated liquid was drained and replaced with a clean 5% K₂CO₃ solution at an ambient temperature of 25°C for the time it took to transfer the samples from the lab to the fatigue testing facility.

This first baseline test resulted in the majority of the samples not failing up to 107 fatigue cycles, which can be interpreted as the long-term fatigue resistance beyond which no failure is probable anymore. To achieve a meaningful baseline of failures, the test criteria were modified to 75% of tensile yield (101.25 ksi) as base load and a fatigue amplitude of +/- 25% of tensile yield, again taking the sample to 100% tensile yield in every cycle.

This second test series achieved the desired failures. However, the spread of the results (failures occurring between 2 million and 8 million cycles) indicated that another influencing parameter had to be eliminated from the test. It was originally intended to run the tests with samples cut out of the weld area between pipe body and tooljoint, as this was expected to be the most critical area of the pipe joint. Due to the relatively large spread of surface hardness values occurring across the weld area, another test series was run with samples cut and machined from the undisturbed pipe body.

This third test series provided a solid baseline for the first series of H₂S-exposed samples. A procedure was selected where the test was started with the most severe exposure conditions to prove sample failures before relaxing the exposure criteria. These initial test conditions were:

<table>
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<th>Influence Factor</th>
<th>Test Condition</th>
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<tr>
<td>Drill pipe materials</td>
<td>S135</td>
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<tr>
<td>H₂S partial pressure</td>
<td>6 bar (87 psi)</td>
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<tr>
<td>Ambient temperature</td>
<td>70°C</td>
</tr>
<tr>
<td>Exposure time</td>
<td>3 hours</td>
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The selected H₂S partial pressure is equivalent to an H₂S concentration of 2% in the formation gas for a shallow reservoir at 3,000 m under hydrostatic conditions or an H₂S concentration of 0.8% in the formation gas for a deep reservoir at 5,000 m under overpressured conditions of 0.15 bar/m gradient.

Again, initial test results were puzzling as some of the exposed samples showed better fatigue resistance than even the undamaged baseline samples. This phenomenon was explained by the fact that hydrogen diffusion is time-dependent. Therefore, higher hydrogen concentrations can be expected below the surface of the steel samples than in the middle of the samples. According to this, heterogeneous hydrogen distribution samples will experience compression stress close to the surface and tensile stress in the center. It is well known that compression stress just below the surface of a sample leads to better fatigue properties.

However, the scatter of the results was still too extensive to define a clear tendency. When investigating one more time
for potential further influencing factors, it became apparent that because of the small diameter of the samples (3 mm), surface influences would become paramount. Therefore, two more test series were done, this time with a mirror-polished finish (Figure 5).

The combined results of the first test series conducted throughout the second half of 2007 (Figure 6) indicate a trend to reduced fatigue resistance after exposure to severe H₂S environments. However, there were no immediate failures, even for S135 material. At the time of this writing, a second test series was being conducted to further populate the area between 105 cycles and 106 cycles to failure and 350 Mpa to 500 Mpa fatigue cycle amplitude, all with mirror finished samples, to confirm the indicated trend of reduced fatigue resistance after exposure to H₂S.

CONCLUSIONS

From the initial six-month testing period, it has become apparent that fatigue loads commonly expected for drill pipe rotating in doglegs under substantial axial load did not create sufficient stress in the undamaged samples to account for failure up to 107 load cycles, which is commonly accepted as long-term fatigue resistance.

The load scenarios that finally had to be applied to achieve failure of the samples is substantially above any loads normally “expected” in the upper parts of a well where SSC hazards are highest (due to highest axial stress, lowest temperatures and highest fatigue stress when rotating the string). The +/- 25% of total yield amplitude would account for roughly 10°/30 m doglegs, way beyond any permissible up-hole dogleg severity.

The substantial scatter in the initial tests showed the severe influence of surface effects on the sample performance. It is being debated whether a move to a full-size (i.e., complete drill pipe joint) test should be targeted for 2008 to eliminate such surface effects on the small machined samples.

Even the baseline tests with mirror finish samples showed a fatigue performance well in excess of the minimum yield strength of 135 ksi. Long-term fatigue resistance appeared to be in the range of 120 ksi, +/- 22 ksi, with initial resistance against 120 ksi, +/- 32 ksi, effectively subjecting the samples to peak tensile loads of >150 ksi.

Early results seem to indicate that the exposure to H₂S reduces fatigue resistance. However, the reduction in long-term fatigue resistance appears to be relatively small. Translated into field conditions, this would indicate that unless the pipe is subjected to severe stresses (taking it to its full yield), it should withstand short-term exposure to sour environments as they occur during kick control activities. However, these findings will have to be substantiated during subsequent test series.

This article is based on IADC/SPE 112678, “What Really Happens to High Strength Drillpipe When Taking a Sour-Gas Kick?” 2008 IADC/SPE Drilling Conference, 4-6 March 2008, Orlando, Fla.