

SULFIDE STRESS CRACKING – PRACTICAL APPLICATION TO THE OIL AND GAS INDUSTRY

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ABSTRACT

The phenomenon of sulfide stress cracking (SSC) can result in catastrophic failures of pressurized equipment and piping, resulting in extensive damage, injuries and possible fatalities. Sulfide stress cracking was first identified as a serious problem in the oil industry in the late 1950's with the development of deeper sour reservoirs. The high strength materials required for these wells began to fail as a result of brittle fracture that was later identified as SSC. Research began on this phenomenon and a task group was formed, which later became associated with the National Association of Corrosion Engineers (NACE), now known as NACE International. The T-1B committee of NACE published a recommended practice addressing the metallic material requirements for protection against SSC. This recommended practice was later issued in 1975 as the Materials Requirement MR-0175, known today as "Metals for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments". Recently, NACE International has issued the International Standard MR0175/ISO 15156 addressing multiple forms of cracking associated with the presence of aqueous hydrogen sulfide. This paper will concentrate on, and identify, the requirements for SSC to occur and give designers and operators practical options for the prevention of SSC in equipment operating in an aqueous H₂S environment. While this paper will primarily discuss SSC, some insight will be given to address the concerns of other forms of cracking.

Key Words: hydrogen sulfide, cracking, sulfide stress cracking (SSC), partial pressure, heat affected zone, post weld heat treatment, hardness, sour environment, metallurgy

INTRODUCTION

Aqueous hydrogen sulfide (H₂S) in oil and gas production operations can result in many challenges. H₂S is a poisonous gas that can result in severe metal loss corrosion as well as catastrophic brittle fractures of pressurized equipment and piping. These brittle fractures to metallic structures can happen quickly, with little to no warning, or may take years of exposure to occur. Several variables can influence a material's likelihood or its resistance to cracking from exposure to hydrogen sulfide. The physical properties of the material, the chemical properties of the material, and the environment to which it is exposed all play an important role in determining whether a material is susceptible to SSC.

Sulfide stress cracking, or SSC, is defined by NACE as the "Cracking of a metal under the combined action of tensile stress and corrosion in the presence of water and H₂S (a form of hydrogen stress cracking)." Through the review of this definition, several factors must be present for SSC to occur. These factors are 1) a susceptible material, 2) tensile stress, 3) hydrogen sulfide, and 4) water. If any one of these factors is missing, sulfide stress cracking will not occur.

MATERIAL PROPERTIES

Steel is essentially a combination of iron and carbon with minor amounts of alloying elements added that enable that iron/carbon combination to perform the mechanical and chemical requirements of a particular grade of steel, or alloy. The primary elements added include manganese, silicon, phosphorus, chromium, nickel and molybdenum. Each of these elements is added in varying concentrations so as to enhance the steel's properties. However, with regards to sulfide stress cracking, or other forms of cracking, these alloying elements must be reviewed, and in some cases, minimized.

Materials have to be strong enough to perform under the conditions we require for our production conditions and designs. However, generally with strength comes brittleness. Steels must be strong to perform, yet ductile enough to prevent brittle fractures. A delicate balance must be obtained. As a result of laboratory testing and field experience, NACE MR-0175:2003 details the parameters of acceptable chemical composition, physical properties, manufacturing processes, and fabrication processes that will yield a material acceptable for use in a NACE defined

sour environment. These parameters, as they pertain to carbon steel materials, will be detailed in a later section of this paper.

FACTORS AFFECTING SULFIDE STRESS CRACKING

Generally speaking, an environment that produces hydrogen sulfide is considered “sour”. However, for the environment to be defined as NACE sour, it must exhibit characteristics that are favorable for the initiation of sulfide stress cracking. NACE MR0175:2003 defines the conditions in which SSC can occur. For the purpose of this discussion, a “sour” environment shall be one in which the conditions are conducive to cracking by hydrogen sulfide.

It is important to understand that the environments which can result in the SSC of materials are very specific in their compositions. SSC does not occur under all operating conditions. Several factors affect whether or not SSC will occur to a particular metallic structure. These factors include the alloy composition, the material’s yield strength and hardness properties, heat treatment, microstructure, fluid pH, partial pressure of H₂S, total applied tensile stress and cold work, temperature, and time. How each of these impacts the SSC potential is discussed below.

Alloy Composition

The composition of a metallic material determines its susceptibility or resistance to various forms of cracking when exposed to particular environments. Generally speaking, iron based materials, or ferrous metals, are more susceptible to SSC than nickel based alloys, or non-ferrous materials. Additionally, various levels of resistance/susceptibility to SSC can be found within a given family of alloys due to chemical compositional differences. Therefore, each material should be reviewed prior to use to ensure it is acceptable for the intended use.

Yield Strength and Hardness Properties

In general, the higher the strength of an alloy, the harder the material and the more susceptible it is to sulfide stress cracking. Although yield strength is a true material property, hardness is not. However, there is a correlation between the two measurements. Generally, the higher the yield strength, the higher the hardness value. In most commercial grades of ferrous alloys, the maximum strength level suitable for sour service use is 90,000 psi yield strength. This roughly correlates to 22 Rockwell C (HRC) or 235 Brinell (BHN) hardness. This is often quoted for ferrous steels used in a NACE sour service. However, through controlling steel chemistry and using special mill processing, this upper limit can be increased. Testing and qualification of materials can be performed to determine its suitability for use in sour systems.

Although hardness is not a true material property, it is the preferred method of testing because it is simple and easy to perform, relatively non-destructive, and in most cases, portable. Hardness values can be utilized by manufacturers and procurement agents as a quality control method during the fabrication process or by the field personnel as a field inspection technique. Additional discussions on hardness determinations are discussed in the next section.

Heat Treatment

The type of heat treatment applied to a particular alloy can affect the material’s microstructure and ultimately its susceptibility to sulfide stress cracking. A microstructure comprised of tempered martensite with fine grains will result in materials of superior resistance to SSC.

Carbon and low alloy steels are acceptable in the as-milled condition as long as they contain less than 1% nickel, meet the hardness requirements, and are in one of the following heat-treatment conditions: hot-rolled (carbon steels only); annealed; normalized; normalized and tempered; normalized, austenitized, quenched and tempered; or austenitized, quenched and tempered.

It should be noted that field fabrication, cold working, and welding of “approved” materials can alter the microstructure, making the material susceptible to SSC. It may be necessary to thermally stress relieve the materials following these processes to “reinstate” their resistance to SSC.

Microstructure

Although susceptibility to SSC increases with increasing hardness, some microstructures are more susceptible to cracking than others at the same hardness levels. As stated above, the tempered martensite is more resistant to SSC

than the tempered bainite or mixed structures of the same hardness. Additionally, the degree of segregation and the type, size, shape and distribution of inclusions are other microstructural variables that can influence the resistance to sulfide stress cracking.

Fluid pH

The higher the fluid pH, the more resistant materials are to SSC. This tendency enables drilling operations to utilize high strength materials in zones known to produce H₂S. Although pH control is acceptable and manageable in drilling operations, it is not readily utilized in production scenarios. Maintaining a constant pH in production would prove troublesome and impractical. Therefore, hardness limitations and alloy selections are the preferred method for controlling SSC.

Partial Pressure of H₂S

As the partial pressure of H₂S increases, the susceptibility of a material to SSC increases. The partial pressure of H₂S is defined as the portion of the total pressure associated with the specific component of interest, in this case, H₂S. The partial pressure is calculated by multiplying the total system pressure by the mole fraction of H₂S in the gas phase. If the calculated partial pressure of H₂S is above 0.05 psia, in a gas system, SSC is possible. Figures 1 and 2 show the relationship to H₂S, system pressure and partial pressure for gas and multiphase systems as illustrated by NACE MR0175:2003 edition. It should be noted that these limits are a “practical” limit; due to other factors affecting SSC, materials have failed at partial pressures below 0.05 psia. Therefore, care should be taken to review all factors involved in the material selection.

Total Applied Tensile Stress and Cold Work

Different alloys possess different threshold levels at which SSC will occur. Understanding this threshold level will enable the designer to ensure that the stresses applied to a material will not result in cracking. It needs to be understood that the total stresses working on a material are the combination of both the applied stress (i.e., pressure) and the residual stress (fabrication/manufacturing stresses). The higher the applied stress on a material, the more susceptible to SSC it becomes.

Cold work or cold formed materials may be susceptible to SSC at hardness levels below HRC 22 (BHN 235). Cold working will alter the microstructure and increase the residual surface tensile stresses. For this reason, heat treatment is recommended for cold worked or cold formed low alloy steels before they are used in a sour environment. An annealing or normalizing heat treatment will return the material to its original SSC resistance following cold working.

Temperature

The potential for SSC decreases as temperatures increase. Therefore, additional high strength tubing and casing materials can be utilized above threshold temperatures. However, if a well is to be completed, or operated, in a sour zone with a temperature above a threshold temperature for a particular material, the engineer must confirm that the environment in contact with the material does not drop below that critical temperature. Below this temperature, these high strength materials are susceptible to SSC and cannot be utilized. Table 1, an excerpt from the NACE MR0175:2003 standard, illustrates the temperature dependence of tubing and casing materials in oil and gas wells.

Time

The general rule of thumb is “the longer the time of exposure, at a constant stress level, the greater the danger of SSC for susceptible alloys”. Under laboratory controlled conditions, it is possible to determine the time to failure of a given alloy under a particular set of conditions. However, in actual field conditions, projecting a time to failure is extremely difficult. The time it takes for a material to fail due to SSC is dependent on the aggressiveness of the environment and the degree of susceptibility of the material. SSC can happen quickly, or may take years to develop. Therefore, it is critical that a review of the materials and environment be conducted prior to specifying the completion equipment. SSC resistant materials should be utilized.

HARDNESS TESTING OF MATERIALS

While hardness testing is a simple procedure, it must be performed correctly and must represent the material in the as-received or as-fabricated condition. Hardness, by definition, is the resistance of a metal to plastic deformation, usually by an indentation. Hardness testers utilize an indenter which is forced into the metal surface by a known loading. The relationship to the area, or depth, of the indentions to the load applied is known as the hardness of the

material. Hardness can be measured on multiple “scales”. NACE MR0175 utilizes the Rockwell C scale (HRC) or the Brinell scale (BHN). If hardness values are specified for the parent metal and any heat affected zones left in the as-welded or as-milled condition, there shall be a sufficient number of hardness tests performed to ensure the readings are below the specified value as noted within NACE MR0175/ISO 15156:2003 for that particular material. Controlling hardness is an acceptable method for preventing SSC. MR0175/ISO 15156:2003 does not specify the number or locations of hardness tests on the parent material. However, if hardness control is to be utilized for approving a welding procedure for use in sour services, specific locations and numbers of tests must be performed. These are noted within the International NACE MR0175/ISO 15156:2003 standard for Vickers and Rockwell Hardness measurements for fillet welds, butt welds and repair/partial penetration welds. These illustrations must be followed for weld procedure qualifications. Figures 3 and 4 illustrate the survey method requirements for hardness measurements on butt welds.

WELDING AND ITS IMPACT ON SSC

Welding is a “necessary evil” in sour systems in the oil and gas industry; however, steps can be taken to minimize its negative impacts. When steel is welded, the parent material and consumables are variables that must be reviewed and controlled. But these are not the only variables that need to be considered when welding in sour service.

The effects of rapid cooling in the heat affected zone (HAZ) of a weld can result in areas of localized hardness. The HAZ is that area around the actual weldment that has been exposed to high temperatures, but not high enough to actually liquefy the material. However, as a result of this heat input, phase transformations do occur, resulting in a microstructure has been “partially melted” and altered due to the heat of welding. This altered HAZ is now more susceptible to SSC due to its increased hardness. A parent material that was suitable and acceptable in regard to SSC in its as-received, as-milled condition may be susceptible to SSC following fabrication that involves welding. Therefore, fabrication processes involving welding must be reviewed for their potential impact on the SSC potential of the parent material.

Weld procedures can be written and qualified as being in compliance with NACE with regard to both SSC and other forms of cracking associated with the presence of aqueous hydrogen sulfide. The qualification requirements for hardness measurements traverse across the weld are detailed in the NACE MR0175/ISO 15156:2003 Standard as stated in the previous section on hardness measurements (again, see Figures 3 and 4).

However, in lieu of qualifying a weld procedure to NACE, one also has the option to post weld heat treat (PWHT) following the completion of the welding. The use of a PWHT technique tempers the welded material. This reduces the residual internal stresses created when the weld metal solidified, and tempers any martensite that may be present into a configuration of lower internal strain. The process of PWHT will be specific for each type and thickness of material and the procedures are described within ASME Boiler and Pressure Vessel Code, Section 8, Division 1.

When specifying line pipe for sour service, it has been this author’s experience to prefer the seamless line pipe over Electric Resistance Weld (ERW) pipe. When ERW pipe was utilized, the specification always called for full body normalizing following manufacturing, verses only seam annealing following manufacturing. In my experience, this proved to provide better resistance to SSC when exposed to the severe H₂S environments in the Permian Basin area of West Texas and Southeastern New Mexico.

USE OF PLATINGS AND COATINGS

While platings and coatings are an acceptable barrier for generalized corrosion, they are not acceptable for use in the prevention of SSC, as per NACE MR0175-2003.

DETERMINING A SOUR ENVIRONMENT

Hydrogen sulfide is one of the most serious corrosion agents encountered in the oil and gas industry. In addition to its ability to crack metals, it can also result in pitting corrosion with subsequent failures. The release of H₂S as a result of corrosion or cracking can endanger the lives of people working around, or in near proximity to, the release point. H₂S can be fatal at concentrations as low as 500 ppm. Therefore, designing equipment resistant to H₂S cracking is critical. Additionally, prevention of corrosion by H₂S is also highly recommended. Inhibition of corrosion can be obtained through material selection, internal coatings, or the application of corrosion inhibitor. However, to prevent cracking, the NACE standard must be strictly adhered to and followed.

It is the responsibility of the owner/user to determine whether a given environment falls within the parameters of a sour environment, thus requiring SSC resistant materials. Information concerning the environment's operating pressure, H₂S content, water content, pH and temperature all play a role in making this determination. Designing for SSC resistance is not only a prudent and good engineering practice, but it is a requirement of many regulatory agencies. Specifically, the Texas Railroad Commission Rule 36, the BLM On-Shore Order #6 and the New Mexico Statewide Rule #118 all specify that SSC resistant materials must be utilized in an H₂S environment. Therefore, this is both critical for safety and regulatory compliance!

Note: Currently, the regulations still specify NACE MR0175, latest edition, as the standard for compliance. It is unknown as of the writing of this paper as to whether the agencies will adopt the new International MR0175/ISO 15156 Standard. However, producers should be aware of the changes published in the new standard and be prepared to make appropriate modifications to fabrication and engineering specifications.

Referring again to Figures 1 and 2 will enable the user/owner to evaluate his/her system based on H₂S content and pressure, assuming the presence of free water.

It should be noted that hydrogen sulfide can be present naturally in produced fluids or can be introduced as a result of contamination by incompatible waters or sulfate reducing bacteria. Frequent surveys of non-sour, or "sweet", fluids should be conducted to determine if hydrogen sulfide generation is occurring over the life of a well or producing field. All safety precautions should be exercised when determining the concentration of H₂S in production fluids. Because of the dangers associated with low concentrations of H₂S, it is recommended to always assume H₂S is present, regardless of the past history of a field, lease, or individual well.

OTHER FORMS OF HYDROGEN DAMAGE

In addition to SSC, there are other forms of hydrogen damage and cracking that can occur in aqueous hydrogen sulfide environments. Because the potential for catastrophic failures associated with these forms of cracking also exists, NACE has recently published a joint international standard NACE MR0175/ISO 15156:2003. This standard addresses the concerns for all types of cracking associated with sour production and makes recommendations for materials and operating conditions to prevent such failures.

Hydrogen Induced Cracking (HIC)

Hydrogen Induced Cracking (HIC) is defined as a "*hydrogen attack induced by decarburization*". This type of attack occurs at elevated temperatures and is caused by atomic hydrogen permeating through the steel and reacting to form other gases. Hydrogen reacts with the carbon in the steel to form methane gas which cannot diffuse out of the steel's matrix. Accumulation of this methane at grain boundaries and other steel discontinuities results in localized high stresses from which cracks can occur. HIC attack generally occurs at temperatures greater than 500^o F and is dependant on the hydrogen partial pressure. Consult the API Publication 941 *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants* for additional information on this phenomenon.

Step Wise Cracking (SWC)

Step Wise Cracking (SWC) is defined as "*hydrogen cracks which lie parallel to each other and are connected by cracks between them*". This type of cracking can be either discrete cracks or an array of cracks. The cracks that connect the "main cracks" and lead to SWC are caused by the shear stresses between the main cracks. This type of cracking can lead to catastrophic failures due to the potential for the cracks to propagate through the thickness of the material, resulting in a considerable loss of strength and ultimate failure.

Stress Oriented Hydrogen Induced Cracking (SOHIC)

Stress Oriented Hydrogen Induced Cracking (SOHIC) is defined as "*hydrogen induced cracking propagated by high internal stresses (typically hoop stress)*". This type of cracking is similar to HIC and SSC, but the cracking is transgranular, or across the grains, in the through thickness direction. These cracks initiate and propagate in the direction normal to the applied stress, and are typically observed in the HAZ of relatively high hardness microstructures. The application of a high external stress (i.e., pressure) typically contributes to the failure.

Hydrogen Blistering

Hydrogen Blistering is defined as the “*subsurface cracking from absorption and concentration of hydrogen*”. Blistering occurs when hydrogen enters the steel and combines into molecular hydrogen at defects present in the steel plate, typically non-metallic inclusions such as sulfides. Hydrogen blistering generally occurs in low pressure equipment such as tanks and pipeline equipment that are exposed to a corrosive environment that contains hydrogen sulfide.

Because of the nature of the manufacturing process of rolled plates, inclusions present in the steels become elongated, with the larger inclusions present and aligned along the centerline of the plate. It is at these larger inclusions that hydrogen blistering tends to occur. The high internal pressures present with the formation of the molecular hydrogen create high internal stresses within the steel that can greatly exceed the yield strength of a material and result in the formation of blisters. These blisters can often be visually observed on the exterior surface of steels in the form of an area of localized “swelling”. They often resemble a “paint blister”, but they are indeed a blister in the steel plate.

The best prevention for this type of cracking is to specify “HIC resistant material” when procuring steel plates. This material has substantially lower sulfur content (usually 0.005% maximum sulfur) and is commonly calcium-treated for sulfur shape control. This lower sulfur content reduces the amount of inclusions present in the steel, thereby reducing the number of available sites for hydrogen to accumulate and form molecular hydrogen. The calcium treatments help to “round” any inclusions that may be present in the low sulfur steel, thereby making it more difficult for hydrogen to enter.

CONCLUSIONS

It is the goal of design engineers and operators to prevent failures, whether they are annoying seeps or catastrophic failures. It is a considerable economic benefit for users of steels to understand the environment in which that steel will be placed and the hazards associated with its exposure to that environment. By understanding the various forms of cracking that can occur to steels, the designer/operator can implement specification changes, or modify the environment to eliminate that mechanism. This will extend the effective life of the equipment, reduce the potential for failures, reduce downtime associated with equipment repairs and make the production area safer with respect to equipment failure incidents.

It is vital when selecting a manufacturing/fabrication process to consider the preventative measures for reducing the susceptibility of steel to various forms of cracking. Some Regulatory agencies require that equipment be manufactured, fabricated, and maintained in a condition that is resistant to Sulfide Stress Cracking (SSC). Therefore, it is critical during the early stages of a project to specify “NACE” trim and “NACE” compliance on all equipment in a sour environment. However, it must be noted that any modifications made to such equipment following its installation must be made such that this “NACE” condition is not negated.

By following the Standards published by NACE, the designer/operator can be confident that the specified equipment is acceptable for use in a sour environment and is resistant to SSC. By applying the details found in the new International Standard NACE MR0175/ISO 15156: 2003, additional protection from other forms of cracking can be integrated into the design specifications.

REFERENCES

NACE MR0175-2003, “Metals for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments,” NACE International, (Houston, TX:NACE)

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Texas Administrative Code, Title 16: Economic Regulation, Part 1; Railroad Commission of Texas, Chapter 3: Oil and Gas Division, Rule 3.36; Oil, Gas or Geothermal Resource Operation in Hydrogen Sulfide Areas, 2004

Bureau of Land Management, Onshore Oil and Gas Order No. 6, 43 CFR 3160, Federal Register/Volume 55, No. 226

New Mexico State Wide Rule 118: 19,15,3.118, Hydrogen Sulfide Gas (Hydrogen Sulfide)

Table 1 - Acceptable API and ASTM Specifications for Tubular Goods
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Acceptable API and ASTM Specifications for Tubular Goods			
Materials listed in this table are acceptable under environmental conditions noted.			
Operating Temperatures ^(B)			
For All Temperatures ^(A)	For 66°C (150°F) or Greater	For 79°C (175°F) or Greater	For ≥107°C (≥225°F)
<u>Tubing and Casing</u>	<u>Tubing and Casing</u>	<u>Tubing and Casing</u>	
API Spec 5CT/5CTM grades H-40, ^(C) J-55, K-55, M-65, C-75 (types 1, 2, 3), and L-80 (type 1) Proprietary ^(H) grades in accordance with Paragraph 10.1.3 UNS K12125 API 5CT/5CTM grades C-90 type 1 and T-95 type 1 <u>Pipe</u> ^(D,E) API Spec 5L grades A & B and grades X-42 through X-65 ASTM A 53/A 53M A 106 grades A, B, C A 333/A 333M grade 1 & 6 A 524 ⁵² grade 1 & 2 A 381 ⁵³ Class 1 Y35-Y65	API Spec 5CT/5CTM grade N-80 (quenched and tempered), grade C-95, T-95 type 2 Proprietary quenched and tempered grades with 760 MPa (110 ksi) or less maximum yield strength Casing and tubing made of CrMo low-alloy steels (AISI 41XX and its modifications) in the quenched and tempered condition at 30 HRC maximum hardness and in specified minimum yield strength (SMYS) grades of 690, 720, and 760 MPa (100, 105, and 110 ksi) (see Paragraph 10.1.3).	API Spec 5CT/5CTM grades H-40, N-80, P-105, P-110 Proprietary quenched and tempered grades to 965 MPa (140 ksi) maximum yield strength	API Spec 5CT/5CTM grade Q-125 ^(G)
Drill Stem Materials ^(F)			
API Spec 5D ⁵⁴ grades D, E, X-95, G-105, & S-135 (See Paragraph 12.3.1.1.)			

^(A) Impact resistance may be required by other standards and codes for low operating temperatures.

^(B) Continuous minimum temperature; for lower temperatures, select from the first column.

^(C) 50 MPa (80 ksi) maximum yield strength permissible.

^(D) Welded grades shall meet the requirements of Sections 3 and 5 of this standard.

^(E) Pipe shall have a maximum hardness of 22 HRC.

^(F) For use under controlled environments as defined in Paragraph 12.2.

^(G) Regardless of the requirements for the current edition of API Spec 5CT/5CTM, the Q-125 grade shall always: (1) have a maximum yield strength of 1,030 MPa (150 ksi), (2) be quenched and tempered; and (3) be an alloy based on Cr-Mo chemistry. The C-Mn alloy chemistry is not acceptable.

^(H) See Paragraph 10.1 and Section 16.

Table 2 — List of Equipment
(Copyright NACE International 2003, Used with Permission)

NACE MR0175/ISO 15156 is applicable to materials used for the following equipment	Permitted exclusions
Drilling, well construction and well-servicing equipment	Equipment only exposed to drilling fluids of controlled composition ^a Drill bits Blowout Preventer (BOP) shear blades ^b Drilling riser systems Work strings Wireline and wireline equipment ^c Surface and intermediate casing
Wells, including subsurface equipment, gas lift equipment, wellheads and christmas trees	Sucker rod pumps and sucker rods ^d Electric submersible pumps Other artificial lift equipment Slips
Flow-lines, gathering lines, field facilities and field processing plants	Crude oil storage and handling facilities operating at a total absolute pressure below 0,45 MPa (65 psi)
Water-handling equipment	Water-handling facilities operating at a total absolute pressure below 0,45 MPa (65 psi)
Natural gas treatment plants	
Transportation pipelines for liquids, gases and multiphase fluids	Lines handling gas prepared for general commercial and domestic use
For all equipment above	Components loaded only in compression
^a See A.2.3.2.3 for more information. ^b See A.2.3.2.1 for more information. ^c Wireline lubricators and lubricator connecting devices are not permitted exclusions. ^d For sucker rod pumps and sucker rods, reference can be made to NACE MR0176.	

Key

X	H ₂ S partial pressure, kPa
Y	<i>in situ</i> pH
0	Region 0
1	SSC Region 1
2	SSC Region 2
3	SSC Region 3

In defining the severity of the H₂S-containing environment, the possibility of exposure to unbuffered condensed aqueous phases of low pH during upset operating conditions or downtime, or to acids used for well stimulation and/or the backflow of stimulation acid, after reaction should be considered.

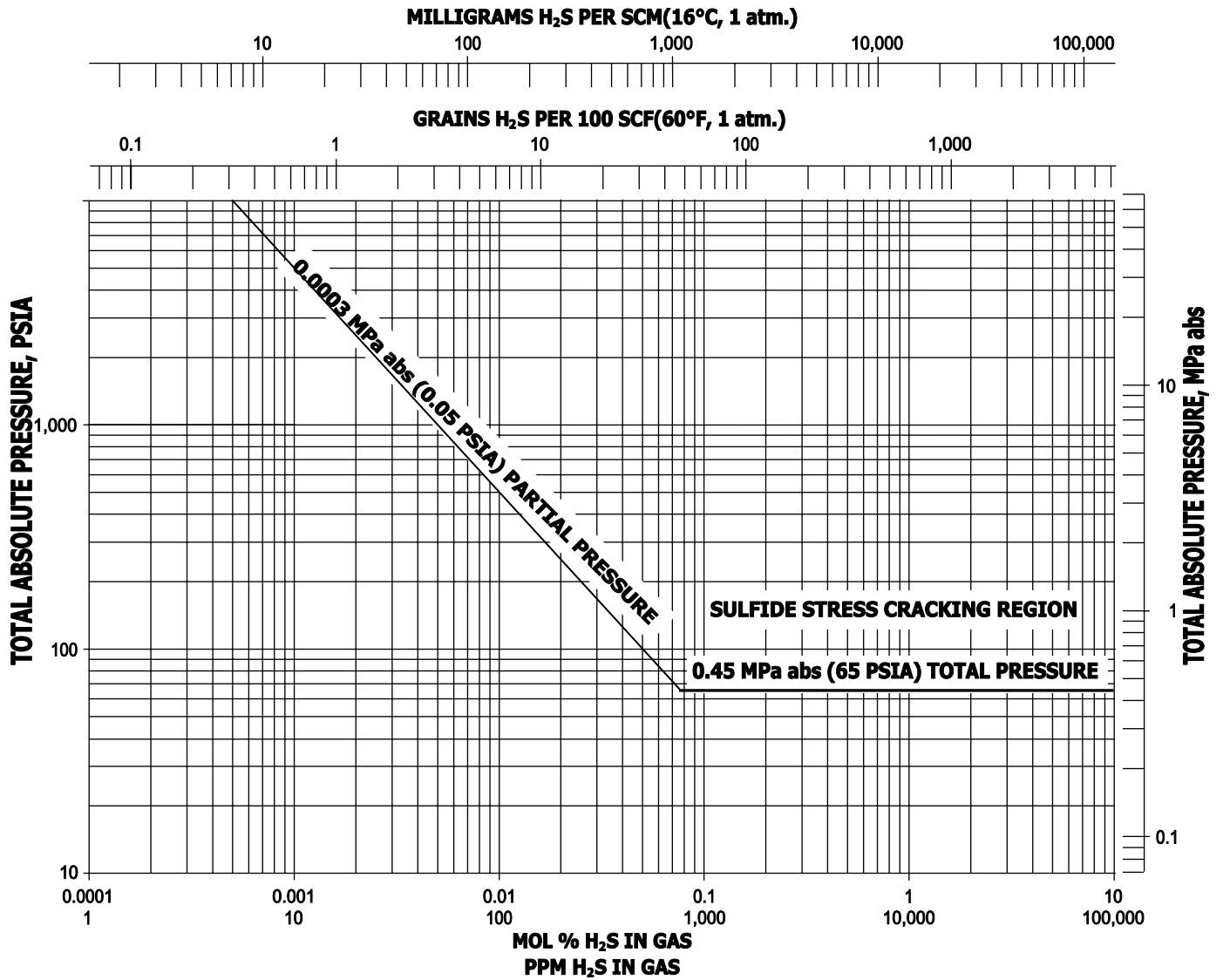


Figure 1 - H₂S Partial Pressure Relationship for a Gas System
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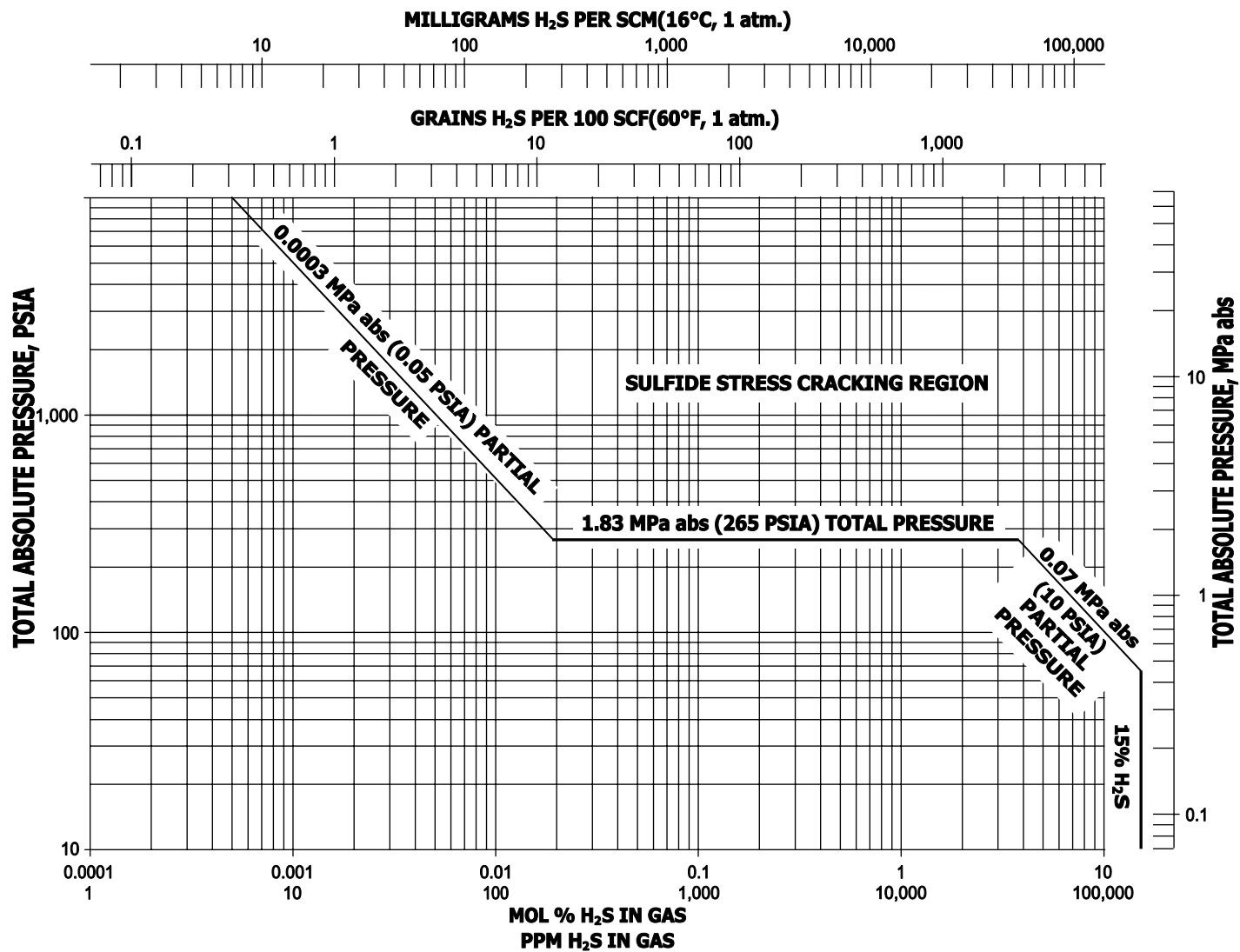
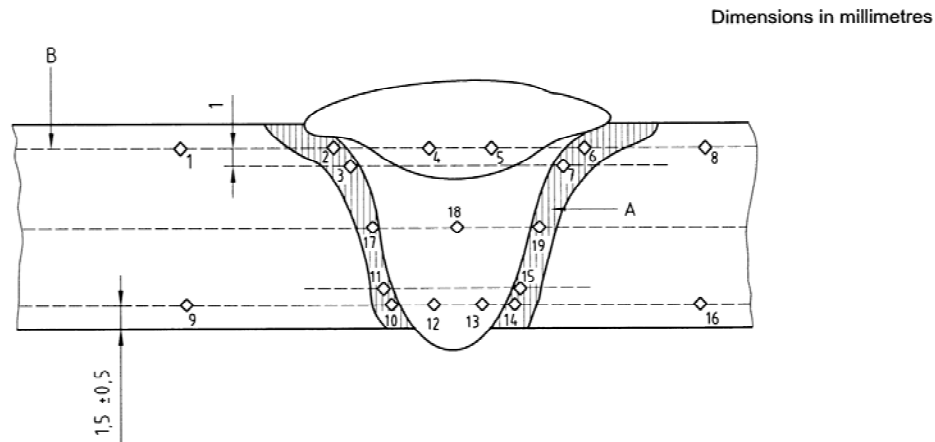


Figure 2 - H₂S Partial Pressure Relationship for a Multi-Phase System
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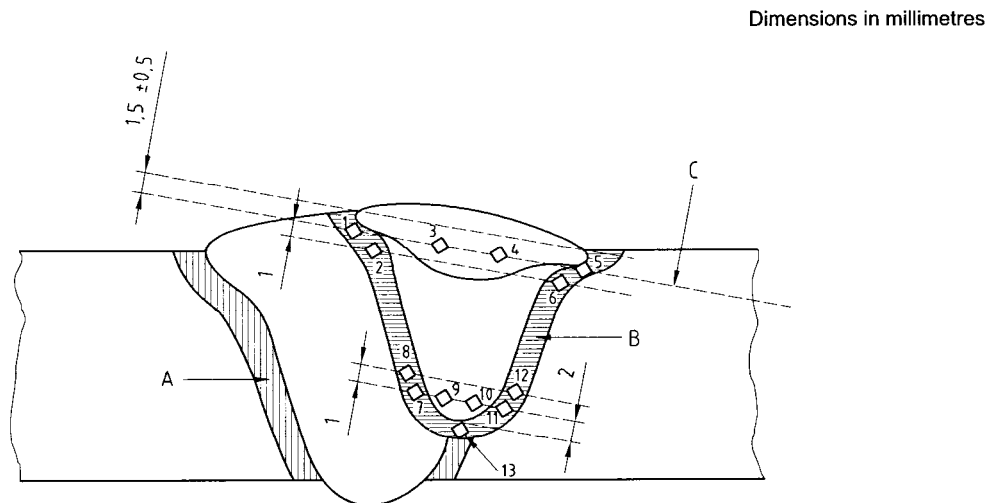
Key

- A weld heat-affected zone (visible after etching)
 B ----- lines of survey

Hardness impressions 2, 3, 6, 7, 10, 11, 14, 15, 17 and 19 should be entirely within the heat-affected zone and located as close as possible to the fusion boundary between the weld metal and the heat-affected zone.

The top line of survey should be positioned so that impressions 2 and 6 coincide with the heat-affected zone of the final run or change of profile of the fusion line associated with the final run.

Figure 3 - Butt Weld Survey Method for Vickers Hardness Measurement
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Key

- A original weld heat-affected zone
 B repair weld heat-affected zone
 C ----- parallel lines of survey

Hardness impressions in the heat-affected zone should be located as close as possible to the fusion boundary.

The top line of survey should be positioned so that the heat-affected zone impressions coincide with the heat-affected zone of the final run or change in profile of the cap of fusion line associated with the final run.

Figure 4 - Repair and Partial Penetration Welds
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