Corrosion prevention approach for gas and oil refinery Tanks

Dr. Hamed Y. Saleh
Ministry of oil, Deputy Minister of Gas Affairs.

Abstract:

Tanks and pressurized vessels are one of the main equipments in the gas and oil refinery industry. Every petroleum industry has a lot of tanks. Gas and oil are corrosive materials, therefore the corrosion losses cost large amount of money and time every year. The severity of corrosion depends on various working parameters such as H_2S level, partial pressure of CO_2, temperature, chloride concentration, surface films and oxide contents.

ألخلاصة:

الخزانات وأوعية الضغط من المعدات المتكررة في المنشات النفطية ، الغاز الطبيعي المصاحب لعملية الاستخراج وكذلك النفط الخام تعتبر مواد أكالة لذلك ترصد مبالغ كبيرة سنويا لمعالجة خسائر التآكل . تختلف آلية التآكل بغاز كبريتيد الهيدروجين حسب ظروف التشغيل, وهنالك عدة معايير تؤثر على طريقة التآكل وبالتالي طريقة المناسبة لمعالجته.

في الدراسة الحالية يتم التركيز على التاكل بسبب الكبريت الناتج من وجود غاز كبريتيد الهيدروجين , تم استخدام ثلاث أساليب لمقاومة هذا النوع من التآكل. الأسلوب الأول بصناعة الخزانات من سبائك الفولاذ التي تبدي مقاومة عالية للتآكل الناتج من الكبريت, والأسلوب الثاني بإضافة جرعات من مثبطات التآكل مع الوقود الموجود في الخزانات, أما الأسلوب الأخير فيتم باستخدام أحد أنواع مادة الايبوكسي Epoxy كطلاء للسطوح الداخلية للخزانات لحمايتها من التماس المباشر من المن توج (الوقود) وكل واحد من الأساليب أعلاه له ميزاته ومحدداته.

Introduction

Oil and gas are the most important raw materials for the production of energy and gas and oil tanks play a strategic role in their industry and transportation. The risk of oil tanker accidents is particularly high, which has been shown in the last decades by many accidents with enormous mass of oil spillage into the roads or surrounding area or leakage of gas to the atmosphere. These oil spillage disasters endangered the natural life and caused an economical loss due to oil or gas loss, out of service time and due to the expenses necessary to deal with oil pollution

Carbon steels are generally used for the petroleum industry for transportation of crude oils and gasses from offshore to different refining platforms and from there to different destination of the applications [4]. Mainly there are two types of corrosion in the oil and gas production systems; CO_2 corrosion (sweet corrosion), and H_2S corrosion (sour corrosion) in the absence of dissolved oxygen [5]. The internal corrosion of carbon steel by carbon dioxide (CO_2) in the presence of hydrogen sulfide (H_2S), known as H_2S/CO_2 corrosion, represents a significant problem for both oil and refineries and natural gas treatment facilities. The phenomenon is complicated because CO_2 and H_2S cause different types of corrosion of carbon steel. The corrosion of CO_2 has received a lot of attention and its mechanisms are fairly understood [6]. On the other hand, the corrosion of H_2S has not received much attention, and even though some mechanisms have been proposed [7, 8] they have not been validated.

Natural gas may be composed of many gases. Only few of these gases are typically found in large concentrations. The largest volume and most beneficial gases in natural gas are light hydrocarbons (methane, ethane, propane and butane). Other gases that may be presented in large concentrations are carbon dioxide, nitrogen, and hydrogen sulfide. H_2S is the most common impurity in the hydrocarbon gases. Table (1) shows the chemical and physical properties of hydrogen sulfide gas.

The “Wet H_2S cracking” problem in oil industry was first recognized in the 1970’s and guidance on material requirements to avoid SSC was published at that time by NACE as MR0175. In earlier days, it was hoped that the blistering and hydrogen induced cracking (HIC) observed in many refinery process vessel were isolated occurrences [3].

The lowest hydrogen flux in steels typically results from corrosion in near natural pH solutions (pH 5.5 to 7.5). The hydrogen flux resulting from wet sulfide corrosion both as the pH increases and as the pH decreases from the near neutral range. Corrosion at the lower (more acidic) pH values is caused by higher concentrations of dissolved H_2S, whereas corrosion at the higher (more alkaline) pH values is caused by higher concentrations of the bi-sulfide ion.

Because of its applications in different industries, corrosion of carbon-steel in H_2S containing solutions is well-known phenomenon that has been investigated for years [5].

The present study focused on hydrogen sulfide, which affects the corrosion rates severely with multiphase condition. Two approaches are reported to prevent the corrosion; first is by adding a chemical material "corrosion inhibiter" to petroleum product stored in the tanks, the second approach is by painting the internal surface of the tank with relevant type of epoxy as an interior surfaces coating to prevent direct contact with the product. Each approach has its advantages and disadvantages.

Corrosion Mechanisms:

The corrosion of mild steel in H_2S aqueous environments proceeds by a very fast direct heterogeneous chemical reaction at the steel surface to form a solid adherent mackinawite scale. The overall reaction scheme can be written as:

$$Fe(s) + H_2S \rightarrow FeS(s) + H_2 \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (1)$$

As both the initial and final state of Fe is solid, this reaction is often referred to as the “solid state corrosion reaction”. The formed mackinawite scale may dissolve depending on the solution saturation level. For the typical pH range seen in oilfield brines (pH 4-7) the solution is almost always supersaturated with respect to iron sulfide and the mackinawite scale does not dissolve, actually in long exposures it may grow slowly by precipitation from the bulk16. If the pH is decreased below pH4 the dissolution rate will increase to a point where in the range pH2-pH3 no mackinawite can be detected on the steel surface [9].

Even if aqueous H_2S is a weak acid just like carbonic acid, the corrosion mechanism proposed above differs in sequence from what is believed to happen to steel exposed to pure CO_2 solutions in the same pH range (pH4-7). In CO_2 corrosion of steel, iron first dissolves to form aqueous Fe^{2+} which then may or may not precipitate at the metal surface to form iron carbonate (e.g. below pH5 iron carbonate typically does not form and above pH6 it is almost always there). In H_2S solutions, steel corrosion proceeds to first form a mackinawite scale which then may or may not dissolve.

The first layer of mackinawite that formed very fast is extremely thin ($<< 1\mu m$) and is invisible to the naked eye and even by a typical SEM [12 into 8]. However it is rather protective and for example reduces a CO_2 driven corrosion rate typically [10].

With increased exposure times, at high H_2S concentrations and temperature, the thin mackinawite film grows rapidly. It is still unclear whether this growth is supported by H_2S penetration through the crystalline layer (by solid state diffusion) or is it by ionic conduction of S^{-2}, HS^- , Fe^{+2}, etc. through the semi-conductive mackinawite matrix. Outward diffusion of ferrous species is consistent with an electrochemical iron dissolution mechanism and a mackinawite continued growth at the outer film/solution interface. The inward diffusion of sulfide species is consistent with the proposed direct chemical reaction mechanism (1) and leads to mackinawite formation at the inner film interface with the steel. In both cases the mechanical integrity of the growing layer is weakened. Outward migration of Fe^{+2} leaves “voids” at the metal/mackinawite interface i.e. it “undermines” the film what manifests itself as poor “adhesion” of the film to the steel. Inward diffusion of the sulfide species leads to internal stresses in the film as described below.

The solid state corrosion reaction (1) keeps generating mackinawite at the inner interface of the mackinawite film with the steel. This leads to epitaxial stresses arising from the different crystalline structures of the source iron and the iron sulfide that formed in its place [11]. What is more important, the solid FeS is calculated to be 2.56 times more voluminous than the iron it replaced, at the mackinawite/steel interface. This, so called Pilling-Bedworth ratio (PBR) [11], leads to an increase of internal compressive stresses in the mackinawite film. When the mechanical limit of the mackinawite is exceeded micro-cracking of the film occurs, thereby relieving the internal stresses and the process starts all over again. These micro-cracks, which most likely occur at mackinawite grain boundaries, serve as preferred pathways for more rapid penetration of sulfide species which fuel the solid state reaction (1) to go faster [9]. It is expected that in some instances, at stress concentration points, large cracks in the film may appear. The sulfide species penetrate even more easily at these locations to feed the corrosion reaction (1), which makes even more sulfide film at those locations and causes even more internal stressing and film failure. It is not difficult to see how this feed-forward scenario could lead to an exponential growth of the reaction rate and localized corrosion. This scenario also offers an explanation for an apparently odd occurrence in H_2S corrosion: experimental observations indicate that pits are usually full of iron sulfide and even have a cap of sulfide which is thicker than elsewhere on the steel surface. This appearance is very different from localized attack in CO_2 corrosion where pits are bare while the surrounding steel is covered with a protective film. Finally, in this scenario the hydrogen gas evolved by the corrosion reaction (1) builds up at the steel/film interface as it diffuses out through the mackinawite film with difficulty. This may lead to the retardation of the atomic hydrogen recombination reaction and hydrogen penetration into the steel. Indeed, the hydrogen built-up at the steel/film interface may even bubble out and cause further damage to the mackinawite film. The last few points are purely hypothetical and were discussed here only because they are consistent with proposed mechanism of H_2S corrosion of steel and the resulting iron sulfide film growth. As there is no direct evidence for them in the short term, these hypotheses needs to be directly confirmed in the future.

As the mackinawite film goes through the growth/micro-cracking cycle, it thickens. As larger crack appear, whole layers of the film may partially delaminate from the steel surface starting another cycle of rapid film growth underneath. Over longer exposures, this cyclic growth/delamination process leads to a layered outer sulfide scale which is very porous. As this outer scale grows it will spontaneously spall a process assisted by flow. Notwithstanding, if the bulk solution is under saturated (typically at $3<pH<4$) the outer porous mackinawite scale will dissolve away as fast as it forms, what may happen even to tight inner mackinawite film at $pH<3.1$

In summary, in H_2S corrosion of mild steel two types of mackinawite layers form on the steel surface:

- Very thin (<<1µm) and tight inner film.
- Much thicker (1-10 µm) layered outer scale which is loose and very porous.

The outer scale may be intermixed with any iron sulfide or iron carbonate that may have precipitated out given the right water chemistry and long exposure time, what would change its properties and appearance. Both the inner mackinawite film and the outer scale act as barriers for the diffusion of the sulfide species fueling the solid state corrosion reaction (1). This is in addition to the diffusion resistance through the aqueous mass transfer boundary layer.

Corrosion Prevention Approaches:

H_2S can attack the crystalline matrix of the steel, leading to embrittlement and cracking of the steel, which could, in turn, lead to possible leakage of H_2S. This embrittlement is invisible and can occur in a short period of time. Corrosion, which is caused by chemical reactions of metal with water and H_2S in the presence of water, oil and gas operations take precautions to remove water from gas streams containing H_2S [12].

Corrosion resistance materials, coating, and chemical corrosion inhibitors may be used to prevent equipment failure and gas releases where H_2S and other corrosive to be presented.

Material Selection Approach: The materials selection process reflects the overall philosophy regarding design life time, cost profile, inspection and maintenance, safety and environmental profile, failure risk evaluations and other specific project requirements [13].

Materials selection provides acceptable safety and reliability, as a minimum. Therefore the material selection requirements shall be considered are:

- Corrosivity, taking into account specified operating conditions including start up and shut-down conditions;
- design life and system availability requirements;
- Failure probabilities, failure modes and failure consequences for human health, environment, safety and material assets;
- Resistance to brittle fracture;
- Inspection and corrosion monitoring;
- Access for maintenance and repair.

The investigation was carried out on the four types of steel alloys, were the chemical compositions shown in the table (2).

Carbon steels are generally used for the petroleum industry for transportation of crude oils and gasses from offshore to different refining platforms and from there to different destination of the applications. The carbon steel is susceptible to internal corrosion due to CO_2/H_2S environment [4, 14]. The comparison of their corrosives in the severe corrosive environment needs further investigation under the dynamic flow condition. The severity of corrosion depends on various working parameters such as partial pressure of CO_2, temperature, chloride concentration, H_2S level, surface films and oxide contents [4]. There are very limited literatures available in the dynamic flow condition under H_2S environment [6, 7,8and 9]. Some parameters, which affect the corrosion rates severely with multiphase flow condition. The surface film mainly consists of $FeCO_3$ and their influence on the corrosion rates were observed in CO_2 aqueous solutions [4]. The formation of iron carbonate is temperature dependent and at higher temperature it forms the protective layers over the metal surface [4]. The effect of H_2S on CO_2 saturated solution has been investigated by adding little amount of H_2S (0.4 ppm) in the same working environment. The H_2S level from the surface has been easily skipped off due to the flow effect of liquid and the corrosion rate increases severely [4].

The prevention of hydrogen blistering and HIC/SOHIC can, to a large extent, is accomplished by appropriate materials selection. In this regard, the Sulphur content of the steel is a key material parameter. Reducing the Sulphur content of the steel, combined with a proper normalizing heat treatment for grain refinement, reduces the susceptibility of blistering and HIC/ SOHIC. The limits of sulfur vary depending on whether equipment is cast, forged, and seamless or made from rolled plate steel, as shown in table (3) [3].

Corrosion Inhibition Approach:

In the oil production industry, economic losses and ecological damage caused by corrosion of metal equipment and structures that come into contact with highly aggressive media. The most important tasks in the development of an oilfield are reliable operation and long life of equipment. The presence of corrosive components in transported fluids negatively affects metal in oil production, refinery, transportation and processing operations [15]

One of the efficient methods of protection is the use of inhibitors that adsorb as protective films on a metal to prevent its corrosion. At the same time, inhibitor protection seems to be one of the most appropriate and cost-efficient ways to address this problem [15].

Improvements in corrosion inhibitor performance may allow to be used for carbon steels instead of corrosion resistant alloys. This approach, however, is only effective when a specially selected inhibitor, usually injected at a high dose rate, is made available for virtually all of the operational period. That is >95% inhibitor efficiency and >95% inhibitor availability may well be required; a much more proactive management activity and difficult task to effect adequately unless properly organized and managed.

Vedage et al. [16] for 4130 steel in H_2S solution at 95 ^oC, finding that the corrosion process for short times is film diffusion limited, whereas for longer times a steady state was reached at which the film growth was balanced by its dissolution into the aqueous phase, leading to a limited film thickness.

Because of its implications in different industries, corrosion of steel in H_2S-containing solutions is a well-known phenomenon that has been investigated during many years [16]. The injection of corrosion inhibitor is a standard practice in oil and gas production systems to control internal corrosion of carbon steel structures.

Corrosion inhibitor injection is a standard practice in oil and gas production systems to control internal corrosion in carbon steel structure, Nitrogen-based organic inhibitors, such as imidazolines or their salts have been successfully used in these applications even without an understanding of the inhibition mechanism [5]. Corrosion inhibition of organic compounds is related to the adsorption properties of the organic compounds and depends on the nature and state of the metal surface, type of corrosive environment, and chemical structure of the inhibitor [5].

Use of corrosion inhibitors in process systems is not recommended, but can be used provided the inhibitor in each process stream satisfies the inhibitor supplier's minimum recommended concentration for each stream and flow rate. Due to complex geometries and normally high flow rates, there is an increased risk for high inhibited corrosion rates locally in process systems compared to pipelines, which will influence the need for inspection and maintenance [13].

In pipeline systems carrying hydrocarbons with condensed water, the corrosivity may be reduced by application of inhibitors in combination with pH adjustment as an alternative to inhibitors alone. The combined effect of inhibitors and pH adjustment shall be qualified [13].

A corrosion evaluation with inhibition should be based on the inhibitor availability, considered as the time the inhibitor is present in the system at a concentration at or above the minimum dosage.

The percentage availability (A %) is defined as:

$$\mathrm{A\%} = 100 \times (\text{inhibitor available time})/(\text{lifetime})$$

Corrosion allowance (CA) = (the inhibited corrosion allowance) + (the uninhibited corrosion allowance)

$$(\mathrm{CA}) = (\mathrm{CRinhib} \times \mathrm{A\%100} \times \text{lifetime}) + (\mathrm{CRuninhib} \times \{1 - \mathrm{A\%}/100\} \times \text{lifetime})$$

where: CRinhib: inhibited corrosion rate.

CRuninhib: uninhibited corrosion rate.

At the design stage an assumption may be made that inhibition can decrease the corrosion rate to 0,1 mm/year. The inhibited corrosion rate shall, however, be documented by corrosion tests at the actual conditions or by relevant field or other test data. It should be noted that to achieve the target residual corrosion rate, high dosages of inhibitor may be required.

The inhibitor availability to be used in a design calculation depends on the planned corrosion management program, including corrosion monitoring and corrosion inhibition. Unless defined otherwise, an inhibitor availability of 90 % shall be used. Maximum inhibitor availability shall not exceed 95 %. 95 % inhibitor availability requires that a qualified inhibitor is injected, and that a corrosion management system is in place to actively monitor corrosion and inhibitor injection [13].

Different additives of organic compounds with different active centers were used to prevent corrosion in acidic solutions [6]. The effect of inhibitor concentration ascribed to the formation of an inhibitive film which then breaks down at higher concentrations [16]. Tang et al. [16] studied the electrochemical behavior of SAE-1020 carbon steel in 0.25 M Na2SO4 solution containing different concentrations of H_2S at 90 °C using weight loss, electrochemical measurements, scanning electron microscopy (SEM) and X-ray diffraction (XRD) techniques. Carboxyethylimidazoline, as an H_2S corrosion inhibitor of API X-120 steel is showed; for example.

Results have shown that the corrosion rate of carbon steel increases significantly with the increase of H_2S concentration. H_2S accelerates the corrosion rate of carbon steel by a promoted hydrogen evolution reaction.

Inhibition Mechanism:

In solutions containing H_2S, the corrosion process of iron and carbon steel is generally accompanied by the formation of an iron sulfide film [16,17]. The corrosion products film is non-protective nature. This film is a non-adherent layer which can be easily removed from the steel surface and can't passivate the steel surface under the environmental conditions used. The protectiveness of the inhibitor film depends, among other factors, upon the adherence and stability of the inhibitor on this iron sulfide film. Generally speaking, it has been accepted that organic inhibitors form a protective layer on the surface of the metal. However, the low concentrations of the inhibitor shows that this film inhibitor is unstable and detached from the metal surface, except for 160 μmol.l-1 carboxyethylimidazoline, where the film formed by inhibitor is more stable.

When the iron sulfide is formed, after some time it cracks and is detached from the steel surface. Unlike this, the steel exposed to the inhibited H_2S-containing solution with high concentration, explains transients of high frequency and low intensity, indicating that during all the testing times the steel is susceptible only to a uniform type of corrosion, and thus, that any film formed by the inhibitor is very stable with time and protects the iron against corrosion.

Various corrosion inhibitors have long been used successfully for the protection of steel equipment and pipelines in oil production, refinement, transportation and processing [15]. Prominent among them are nitrogen-containing compounds with a diphilic structure, i.e. colloidal cationic surfactants. Because of their inherent hydrophilic protonated amino and imino groups or a quaternary (charged) nitrogen atom, they can firmly adsorb on the negatively charged steel surface, while a hydrophobic substituent – e.g. alkyl chains composed of 12 or more carbon atoms – orientates the inhibitor during adsorption to form a polymolecular barrier layer that reliably screens the metal from the corrosive medium [15].

In acidic media H_2S stimulates steel corrosion and accelerates hydrogenation, causing the steel to become brittle and crack. The hydrogen concentration after exposure to H_2S-containing solutions increases over time, reaching 8cm^3/100g steel. In the presence of H_2S, corrosion inhibitors should prevent absorption of hydrogen by steel. A lot of inhibitors effectively decrease the corrosion rate, but they do not affect the hydrogenation of steel [15].

Epoxy Guarding Internal Surfaces Approach:

Fusion Bonded Epoxy (FBE) Powder Coatings are widely used in the oil and gas-industry to prevent the attack of corrosive fluids contacting metal equipment. The most used metal in the oil and gas field service is carbon steel, which is susceptible to corrosion by water-saturated natural gas containing hydrogen sulfide. Hydrogen sulfide is one of the most deteriorating factors as far as organic coating are concerned. Hydrogen sulfide reacts directly with metal substrates, pigments, fillers, and metal originating additives, giving rise to degradation and discoloration.[1]

The performance of the coating system depends on the selection of the correct material for the intended service and on its application technique. To protect the internal surfaces, barrier coats (primers) were applied for the freshly blasted pipe surface. High diffusion persistency by filling out micro pores and micro cavities originates from blasting.

Fusion bonded epoxy coating, also known as fusion-bond epoxy powder coating and commonly referred to as FBE coating, is an epoxy-based powder coating that is widely used to protect steel pipe used in pipeline construction from corrosion. FBE coatings are thermo-set polymer coatings. They come under the category of protective coatings in paints and coating nomenclature. The name fusion-bond epoxy is due to resin cross-linking and the application method, which is different from a conventional paint. The resin and hardener components in the dry powder FBE stock remain un-reacted at normal storage conditions. At typical coating application temperatures, usually in the range of 180 to 250 °C, the contents of the powder melt and transform to a liquid form. The liquid FBE film wets and flows onto the steel surface on which it is applied, and soon becomes a solid coating by chemical cross-linking, assisted by heat. This process is known as “fusion bonding”. The chemical cross-linking reaction taking place in this case is irreversible. Once the curing takes place, the coating cannot be returned to its original form by any means. Application of further heating will not “melt” the coating and thus it is known as a “thermo-set” coating.

Results and Discussion:

The corrosion rates starts instantaneously still at low temperature due to continuous dissolution of $Fe2^+$ ion in the solution. As the temperature increases corrosion rate increases due to the formation of porous iron carbonate films, results in the initiation of cracks and spallation of the oxide layers formed on the metal surface [4]. The chloride ion easily ingress through the surface and significantly increases the corrosion at the temperature range of 60-90°C [4].

Son et al. used the STQN method to determine the structures for the transition states between the products and the reactants shown in each of the reactions given in Figure 1.

Further increase in temperature the corrosion rate decreases significantly due to the formation of denser, adherent and homogeneous layer of iron carbonate, which is, protects the metal from further corrosion [4]. For example; Carboxyethylimidazoline, used as an H_2S corrosion inhibitor of API X-120 steel. The lowest corrosion rate values are obtained with (160 µmol/l) of carboxyethylimidazoline, although a significant reduction in the corrosion rate is reached with the addition of (80 µmol/l) of Carboxyethylimidazoline. Lower or higher inhibitor concentrations are reducing the inhibitor efficiency [18].

The corrosion process for short times was film diffusion limited for 4130 steel in H_2S solution at 370 K, whereas for longer times a steady state was reached at which the film growth was balanced by its dissolution into the aqueous phase, leading to a limited film thickness.

Conclusions:

1. Low sulphur steel is to be used with qualified HIC resistant properties [3].
2. During fabrication, recommended weld hardness with PWHT shall be maintained for SSC resistant steel [3].
3. Wet H_2S system is to be periodically re-inspected even if made of HIC resistant steel because steel may not be total resistant in actual refinery operation [3].
4. Depending[†] on the corrosion detection technique information about the type of corrosion an alloy can be susceptible to. For example, the electrochemical noise can give information about the type of corrosion, either localized or uniform.
5. For all the inhibitor concentrations which efficiency decreased as time elapsed.

6. For every type of corrosion inhibitor, there is an optimal concentration. Lower that the localized corrosion is dominated; moreover for high inhibitor concentrations the steel is susceptible towards a uniform type of corrosion.

† Localization Index " *LI*" defined as:

$$LI = \frac{\sigma_i}{i_{rms}}$$

were σ_i is the current noise standard deviation and i_{rms} the current root mean square value [16] which establishes that for *LI* values between 1 and 0.1, the type of corrosion that the material suffers is localized, when the *LI* value lies between 0.1 and 0.01, there is a mixture of both uniform and localized types of corrosion; finally, for *LI* values between 0.01 and 0.001, there is a tendency towards a uniform type of corrosion.

Table (1) Physical and Chemical Properties of Hydrogen-Sulfide [12].

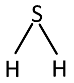
chemical formula	H_2S	molecular weight	34.08
molecular structure		solubility in water	1 g dissolves in 242 mL at 293 K
		flammable limits	lower explosive limit (4.3E07 ppb)
molecular weight	34.08		upper explosive limit (45.5E08 ppb)
boiling point	212.6 K	melting point	189 K
specific gravity (H_2O=1)	0.916 at 212 K	odor threshold	20 ppb
vapor pressure	20 atm. at 299 K	vapor density (air=1)	1.19

Table (2) Chemical composition of steel alloys.

Grade	C	Mn	Si	S	P	Cr	Ni	Mo	Al	Cu
API X-52	0.09	1.31	0.25	0.006	0.012	0.009	0.07	0.003	0.03	0.08
API X-56	0.12	1.27	0.26	0.004	0.017	0.07	0.14	0.19	0.02	0.14
L-80	0.39	1.73	0.25	0.007	0.024	0.001	0.07	0.15	0.03	0.06
API X-60	0.07	1.48	0.27	0.004	0.013	0.09	0.02	0.008	0.04	0.20

Table (3) Sulfur Content to HIC prevention.

Manufacturing Route	Steel-Sulfur below which there is no HIC
Cast	<0.025%
Forged	<0.025%
Seamless	<0.01 %
Rolled plate steel	<0.003% or <0.005% + calcium treatment

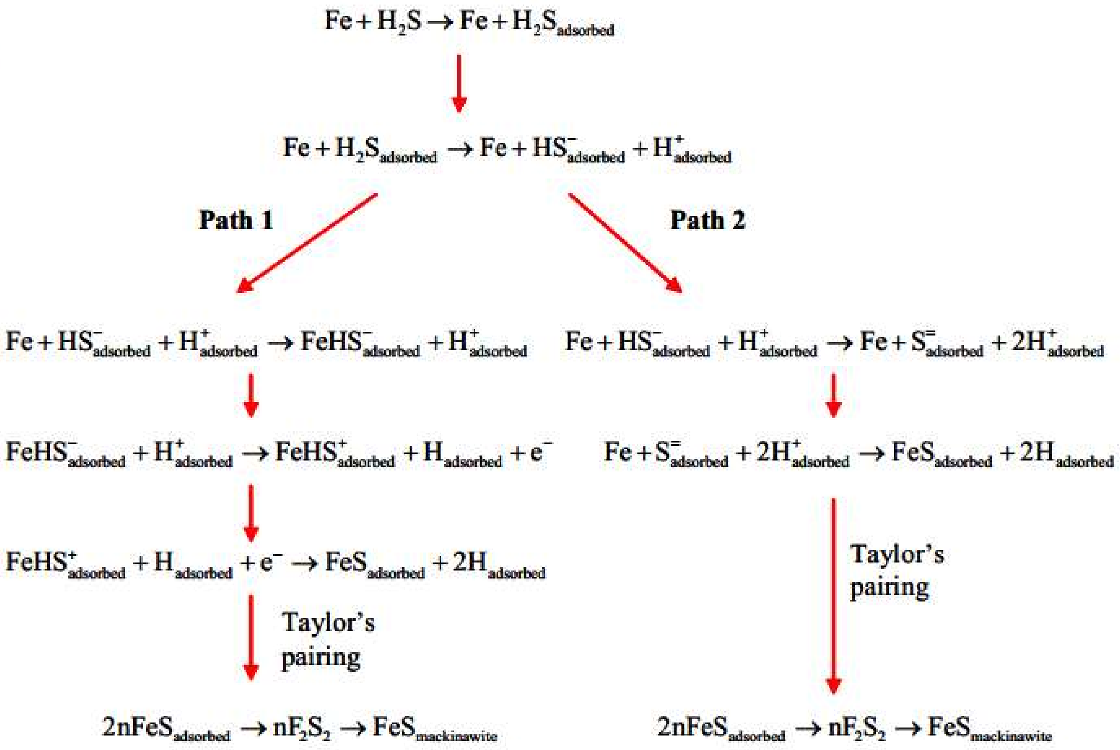


Fig.(1).Proposed mechanisms for H_2S corrosion of Fe (10-11). After the initial adsorption of H2S on theFe surface, Mackinawite can be formed from amorphous FeS either by Path 1 or Path2.

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Abbreviations:	
HIC	hydrogen induced sulfide
FCC	fluid catalytic cracking
SOHIC	stress oriented hydrogen induced cracking
SSC	sulfide stress cracking
PWHT	post weld heat treatment
SCC	stress corrosion cracking
CRA's	corrosion resistance alloys
LPR	linear polarization resistance.
EIS	electrochemical impedance spectroscopy.
EN	electrochemical noise.