



Review article

## Corrosion in Polyethylene Coatings Case Study: Cooling Water Pipelines



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### ABSTRACT

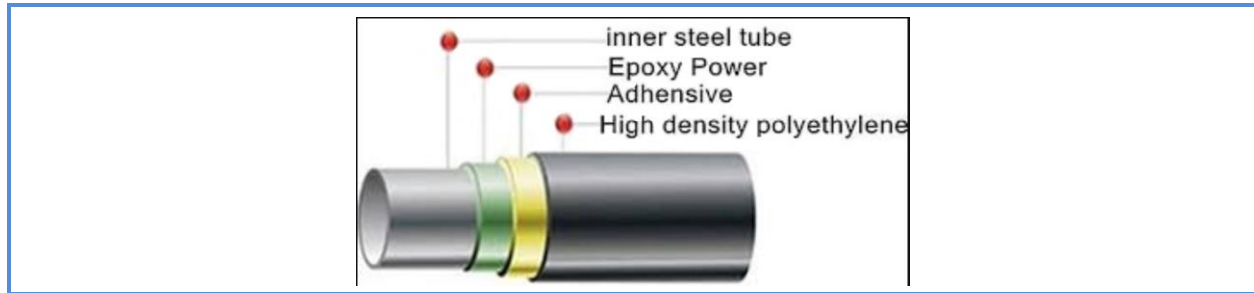
Corrosion has been the greatest problem in oil and gas industry, and many experts have always tried to combat this major problem. This has been given to the corrosion and inspection in oil and gas industry. Corrosion in oil and gas wells is driven by some electrochemical mechanisms, and when the system reaches a temperature below the dew point, the moisture will be converted to liquid and many droplets form on the pipe's wall. The corrosion in pipelines' coatings is one of the main problems in oil and gas industries for which a huge amount of money is spent each year. Coating is the first defense line in front of a corrosive environment in which pipes have been buried. Good function of coating depends on its adhesion to the metal surface. Finally, according to our results in this article, we show that, the chemical compounds inside the coating such as chlorides and sulphides can play an electrolyte role, which accelerates corrosion.

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## Graphical Abstract



## Introduction

In recent years, pipeline-operating temperatures have risen by increasing the temperature, depth of petroleum wells, attraction of petroleum wells, and efficiency of transportation between factories. It has also been designed and built over the years for many different transitions (such as pipes to transport fluid and gas and crude petroleum) [1].

The highly transparent polyethylene coatings (used in North America) are in limited use in the main transmission lines of corrosive petroleum wells. Increasing the operational temperature of the pipeline and the operational air system sectors are important for heavy developed protection coatings at different temperatures with evaluated high durability. It was reported that, durability of pipes has increased by using the polyethylene coatings.

Stainless steel coatings, steel pipe tightness and the pipeline affecting layers before ruining are the other benefits to prevent corrosion. The primary tar of steel pipes is used for the outer stainless steel material, but in recent years' polyethylene coatings has significantly improved the conditions of preventing the corrosion. Mostly, large polyethylene coatings are made in large factories and installed [2]. The conducted tests with world terms belong to light owner companies have been created to increase production capacity as well as the type of availability of materials and their type of size. Special properties such as temperature ranges from 45 degrees centigrade to 80 degrees centigrade [3].

The unique properties of these polymers are special which have this ability to coat at temperatures below 500 °F. Increased type of coated polyethylene is about 1 inch from the edge. The pipe and the corroded joints should be burnt clean from any type of corrosion and this is based on ISO 8501-1 standard [4-6].

**Table 1.** Physical properties of top-coat polyethylene (3)

Physical properties	Unit	Test method	SK ET 509B (Typical)
Melt flow rate	Dg/min	ASTM D 1238	0.3
Density	g/cm <sup>3</sup>	ASTM D 792	0.949
Tensile strength at yield	Kg/cm <sup>2</sup>	ASTM D 638	180
Tensile strength at break	Kg/cm <sup>2</sup>	ASTM D 638	300
Ultimate elongation	%	ASTM D 638	800
Hardness	Shore d	ASTM D 2240	60
Vicat softening point	°C	ASTM D 1525	120
Brittleness temperature	°C	ASTM D 746	<-70
Melting point	°C	ASTM D 3418	128
ESCR	Hr	ASTM D 1693	>1.00
Water absorption	Wt%	ASTM D 570	<0.01
Carbon black content	Wt%	ASTM D 1603	2
Oxygen induction time	Min	ASTM D 3896	15
Volume resistivity	M	ASTM D 257	>10 <sup>16</sup>
Dielectric withstand	Kv/mm	ASTM D 149	38

**Table 2.** Physical properties of polyethylene (2)

Physical properties	Unit	Test method	LE 149 V	LE 200 T	LE 100 A
Melt flow rate	Dg/min	ASTM D 1238	1.6	4	4.9
Density	g/cm <sup>3</sup>	ASTM D 792	0.921	0.927	0.916
Tensile strength at yield	Kg/cm <sup>2</sup>	ASTM D 638	200	180	180
Ultimate elongation	%	ASTM D 638	850	800	820
Hardness	Shore d	ASTM D 638	48	47	47
Vicat softening point	°C	ASTM D 2240	102	102	86
Brittleness temperature	°C	ASTM D 1525	<-70	<-70	<-70
Melting point	°C	ASTM D 746	121	121	120
Water absorption	°C	ASTM D 3418	<0.01	<0.01	<0.01

### Key conservation factors in sour systems

The basis of the Ph consolidation method in environments containing H<sub>2</sub>S (sour environment) is similar to sweet environment (lack of H<sub>2</sub>S).

But the following fundamental differences must be considered:

- ✓ In sour environments similar to sweet environment, the protective layer corrosion products forming is the basis of protection [7].
- ✓ Due to the very low solubility of iron sulphide, in comparison with the iron carbonate (a thousand times less) the iron sulphide layer has better protection than iron carbonate, and as soon as the amounts of H<sub>2</sub>S are required, the layer of iron sulphide is formed. Iron sulphide is composed of crystalline forms depending on pH and temperature. These sulphides have a different protection capability in certain pH.

- ✓ Due to the temperature effect, the minimum protection is in range from 60 to 70 degree centigrade. At this temperature and in low pH, the tendency to pore in steel is seen, so pH control is critical at this temperature. At pH=60 to 70 degree centigrade (the most critical temperature), there was no appetite for corrosion, and iron sulphide layers also had the highest protection in the same pH.
- ✓ As expected, the fluid flow velocity does not affect the quality of the total length of the pipe (8).

### **Corrosion monitoring in pH consolidation method**

The corrosion monitoring is performed through continuous pH examination. The pH value should not be less than desired. If appropriate, the pH value can be ensured from the protection of the entire pipeline. The pH value can be examined using a pH probe. That's the perfect solution. Because monitoring is automatically done. However, the application of these probe is not recommended in sour systems. Therefore, total company evaluates the pH of the environment by examining glycol water conditions under the experimental conditions (1 barg pressure and CO<sub>2</sub> gas). Also, corrosion monitoring is performed using coupons and electrical probes at the point of six o'clock at the input and output of the lines [9-11].

### **Corrosion in gas pipelines and wells**

#### **Corrosion mechanism**

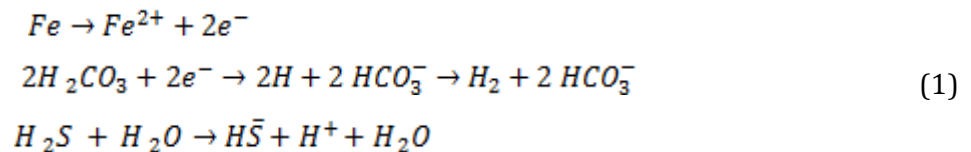
Petroleum and gas wells are divided into three categories.

Petroleum well: it is a well that its main product is liquid hydrocarbon.

Gas well: it is a well that its main product is gas hydrocarbon.

Condensate: The well that there are significant amounts of liquid hydrocarbons with a bit of gas in high pressure and temperature. Each of these wells is divided into sour or sweet. Sweet well is a well containing low amount of H<sub>2</sub>S and a sour well has high amounts of H<sub>2</sub>S. Since clearly the boundary between sweet and sour is not known, some wells can be put in either classification, but generally the values lower than 1% (trace) hydrogen sulphide (H<sub>2</sub>S) are sufficient to be read a sour well. Other gases, such as carbon dioxide or acetic acid, and other aliphatic amino acids with short chains may be produced in small or large quantities. The presence of these gases and acids makes the problems of corrosion control complex in wells. Corrosion of petroleum and gas wells has electrochemical mechanism. When the system reaches the temperature below the dew point, the moisture becomes liquid and large number

of drops will be made on the pipeline wall. Water plays the role of the electrolyte in an electrochemical reaction [12]. The water generated is not corrosive, by itself. When acid gases such as H<sub>2</sub>S and CO<sub>2</sub> are dissolved in water, they provide an acidic environment that is exposed to extreme corrosion steel. In petroleum wells, oxygen is sometimes known as corrosive gases, but there is no oxygen in gas wells. The source of H<sub>2</sub>S gas can be deposits in ground layers, sub-products of the process of petroleum and gas formation, or bacteria activity. Dissolving of H<sub>2</sub>S leads to the creation HS<sup>-</sup> ions (bisulfide) and dissolving of CO<sub>2</sub> makes HCO<sub>3</sub><sup>-</sup> (bicarbonate) [13-16]. PH of these kind of systems is not low enough which can make S<sup>2-</sup>, CO<sub>3</sub><sup>2-</sup> ions then the following reactions will be took place:



Due to these reactions the pH of the environment reaches 5-7. Most of the destruction in the gas well occurs due to local corrosion. The local corrosion that can be occurred under insulators, deposits, or caused by bacteria can be destructed 10-100 times faster than uniform corrosion [17].

### Effective factors for gas well corrosion

Temperature: The effect of temperature in fluid corrosion, petroleum and gas industries is similar to other chemical environments. In most corrosion reactions, the temperature increases the corrosion rate so per 20 °F (11 °C) temperature increasing, the corrosion rate will be doubles. There are three types of temperature regimes in the vicinity of CO<sub>2</sub> corrosive gas [18-19].

- 1) Iron carbonate is soft and non-protective at the less than 60 °C temperature, and the corrosion rate is a function of CO<sub>2</sub> partial pressure.
- 2) An almost protective iron carbonate layer will be formed at the temperature between 60 °C and 150 °C then the corrosion rate will be reached a significant value.
- 3) Magnate layer will be made which is completely protective at the temperature more than 150 °C and it is resistant to high speed and severe turbulence and is only sensitive to chloride ion. However, these three types of regime are without considering the impact of brine composition, fluid velocity, and partial pressure of H<sub>2</sub>S gas to CO<sub>2</sub> gas on corrosion rate. These factors should also be inserted into the definition of formed layer protection.

Pressure: high pressure of gas well is effective on corrosive gas solubility in liquid. Gas pressure will reach 12000 psi. The important point is the partial pressure of each corrosive gas. The corrosively value of a well based on amount of CO<sub>2</sub> gas produced is as follows:

- ✓ Partial pressure of CO<sub>2</sub> less than 7 psi: non-corrosive environment
- ✓ Partial pressure of CO<sub>2</sub> between 7-30 psi: corrosive environment
- ✓ Partial pressure of CO<sub>2</sub> more than 30 psi: highly corrosive environment

Dewaard and Milliams investigated the quantitative effect of partial pressure of CO<sub>2</sub> gas and temperature on corrosion rate. Dewaard introduced the control stage of corrosion rate as acid carbonic reduction and presented the following equality to uncoated steel corrosion.

$$\text{Log } V = 0.67 (\text{log } P_{\text{CO}_2}) + C \quad (2)$$

In this equality V: corrosion rate, P<sub>CO<sub>2</sub></sub>: partial pressure of CO<sub>2</sub> gas and C is a constant number. This equation is true for the initial corrosion rate of CO<sub>2</sub> gas pressure over 2 bar and at ambient temperature up to 60 °C.

### **Fluid corrosive role**

Experience shows that there are usually wells with corrosion problems that the water cut value of per water in the entire fluid is more than 85%. There are many exceptions, of course. The present emulsion of well fluid affects the conductivity and effectiveness of the fluid as a conductor. In general, the wells that produce large amounts of water (no emulsion) are more corrosion than wells with lower water cut and more emulsion. Worldwide organization for corrosion engineering NACE and natural gas producer's organization have introduced two types of corrosion in gas wells:

1. Water independent corrosion: it is a kind of corrosion in petroleum and sweet and sour gas wells when will be occurred that the amount of water be less than 0.1 percent. In this type of well, corrosion will be started with the creation of first particles of water.
2. Water dependent corrosion: this type of corrosion will be made in some petroleum and gas wells where produce large amount of brine water. In well with such corrosion, corrosion may not be observed for years after the start of production. Bregman believes that corrosion has the biggest corrosion problems in the condensate wells. In these wells the ratio of gas to hydrocarbon is high and there is high pressure. The production of large amount of hydrocarbon, along with small amount of water, causes a concentrated acid in the vicinity of the metal surface. It contains a large amount of fatty acids and carbon dioxide. There have

been many investigations to determine fluid dynamics in a well. Bradburn had investigated 20 different wells and the amounts of water and acid gas produced  $\text{CO}_2$  as a variable. He found the quantities of water that were produced, the amount of  $\text{CO}_2$  in the solution adjacent to the wall would produce more and would make more corrosion. Hausler and his partner studied 45 gas wells containing  $\text{CO}_2$  and  $\text{H}_2\text{S}$  in terms of the rate of corrosion and quantities of production water then reached the following equation 3:

$$\text{Average Corrosion Rate (mpy)} = k^G + Q_{\text{H}_2\text{O}} \quad (3)$$

The amount of water produced per BPMMCF (Bars per million cubic feet) and  $K^G$  is the proportionality factor associated with gas production rate:

$$\text{Log} K^G = \log C_h + k^\circ \log Q_{\text{gas}} \quad (4)$$

$Q_{\text{gas}}$ : production gas rate with MMCF unit and  $C_h$ ,  $K^\circ$  are related to chemistry system. This relationship indicates uniform corrosion and is not used for local corrosion, and unfortunately local corrosion is seen more in the wells. Crolet and Bonis have conducted local corrosion investigations. They found that any crack, impurities, and pit caused a local pH change and makes extreme local pH. With the help of electrochemical impedance (EIS) and electrochemistry noise (ENS) techniques in such systems, it is easy to predict uniform and local corrosion.

### Fluid velocity

Fluid velocity is a vital role in the determination of fluid regime and the fluid diet determines the type of corrosion and efficiency of any inhibitor. The experiments have shown that the mechanism and rate of corrosion will also be the same in both conditions if the fluid regime is the same in the experiment and field. Regardless of the fluid diet, in order to study the effect of velocity in corrosion, we should consider three temperature zones. Corrosion of  $\text{CO}_2$  at low temperature (less than  $20^\circ\text{C}$ ), in the range of corrosion depends on hydrolysis velocity and is independent of velocity.

In the range from  $20^\circ\text{C}$  to  $60^\circ\text{C}$ , velocity also plays a little role on corrosion because the slow-off step is diffusion reaction of  $\text{CO}_2$ . But magnate layer will be formed at high temperature condition (over  $150^\circ\text{C}$ ). Abrasion velocity can be raised by 15 m/s without damaging the corrosion product layer. Unless there are factors like the chlorine ion.

Therefore, if the well temperature is above 150 °C and the chlorine ion does not exist, there is no corrosion type unless the fluid velocity is more than 15 m/s but if the temperature is lower than 150 °C only the head of the well becomes corroded. However, if there is a high water production, all over the wells will be exposed to corrosion. It is impossible to predict the rate of corrosion in gas wells at a temperature range of 60–150 °C, and sometimes there is a stable state in which the product decomposition velocity is equivalent to its product velocity. Shear stress caused by fluid velocity reduces the thickness of the protective products [11].

### **Fluid combination**

As mentioned before, the brine combination is effective in terms of dissolved solid particles on the protective layer formation. The chlorine in the water is not corrosive by itself and is only contributing to the deterioration of the carbonate layer and rise in the corrosion rate. The presence of gas condensate also, in turn, prevents the corrosion even a number of condensates containing natural inhibitors but not stopping local corrosion.

### **Metallurgy**

The morphology and alloy applied type effects on the value and corrosion type in the system. Perlites are corrosive in J-55 steel. In Martsin steels such as C-75 and N-80 is observed local corrosion less. The injured yellow corrosion of heat-treated steels has been observed. The steels in the vicinity of hydrogen sulphide tends to be cracked which depends on alloy elements and their phase structure and hardness. A good instruction has been predicted to choose a steel in sour systems in 1F166 NACE standard. The steels undergo tensile corrosion or SCC in the vicinity of H<sub>2</sub>S that created hydrogen on the same metal-electrolyte interface is the main factor for these cracks.

With statistics and figures mentioned above, we find that the corrosion costs cover a very high volume of national funds in countries. With taking a short look at the experience of other countries, it is noticed that many countries currently consider appropriate measures to deal with damage caused by their mistakes. For example, U.S. army announced with wide advertising in 2001 that the corrosion costs in the military has been decreased from 10 billion dollars in year 2000 to 8 billion dollars in year 2001. A basic requirement for corrosion experts in the US was to carry out systematic studies to estimate the cost of metallic corrosion on American economy and develop a strategy to reduce corrosion costs. In the same vein, based on the talks between the American society of corrosion engineers (NACE) and members of Congress and the department of transportation, a reform plan for the cost of steel in transportation was introduced in the 21 st



century, which was accepted by Congress in 1998. In year 2001, the project of corrosion costs was presented in the United States, where the direct corrosion cost was carried out by an analysis of 26 sectors of the industry with complete corrosion information, and the extraction information was extended by extrapolation results for all parts of the country. Finally, the total direct corrosion cost estimated corrosion was about 276 billion dollars a year, equivalent to 1, 3 percent of the total America GNP.

### **Coating operation**

The outer of steel should be dry and excluded from any type of infection (petroleum, Grace, temporary corrosion protection, *etc.*) that is harmful to the skin lining. The clean outer surface should have roughness ( $R_2$ ) between 40  $\mu\text{m}$  and 90  $\mu\text{m}$ . The measurement is according to the standard ISO 4287-1. After the clean outer layer, the layer on the tube must be clarified. All the plates of silver, welding and faulty layers should be removed from the tube. After removal of this defect the thickness of the tube and connections should not be more than acceptable minimum that obtained by the relevant standard. All the prepared areas greater than 10 $\text{cm}^2$  must be improved by preparing a healthy profile [28]. The chemical behavior of steel may cause burning of the outer layer in addition to corrosion. The coating facilities include a primary mechanical coating layer, extruder in polyethylene, polyethylene unit, and mechanisms to press the extruder sheets in polyethylene against the steel tube layer. Polyethylene is formed inside a single sheet, which is an excellent glue by combining two extruders, one for polyethylene adhesion and other for polyethylene combination with a T-shaped die. These sheets are wrapped around the pipe, while it is made from the beginning of the tube by pressing against the direction of the narrow gut pressure and high adhesion to create a primary layer. Although this is chosen by selecting a method of a sheet and pressure rollers with a spiral motion. This may be set by a layer of the total surface layer to perform this scheme.

### **First layer**

Immediately after the pipe is made a form by a film of liquid or gum powder. The minimum dryer should be by 20-60 micron (according to the ISO 2808 method), which is dependent on the initial material. The thickness can be increased or decreased in it's rang with customer and factory agreement.

Note 1: The epoxy limiting mixing (first layer) is used for corrosion protection.

**Table 3.** Effects of irradiation on mechanical properties by multilayer films in machine direction and in cross direction (2)

Material	Dose (k y)	Tensile strength (M Pa)		Percent elongation at break		Young`s modulus (M Pa)	
		md	cd	md	cd	md	cd
A1	0	18.6±0.7	12.5±1.0	373±16	780±56	179±13	197±8
	5	18.4±1.3	14.8±0.9	398±40	868±37	170±11	191±15
	10	18.0±0.8	18.0±0.8	373±25	852±54	172±13	172±13
	30	18.9±1.2	16.0±1.1	415±35	858±37	180±19	197±23
	60	20.5±1.4	17.5±1.2	426±30	859±43	181±9	190±20
A2	0	18.4±0.3	14.4±1.0	351±10	754±25	196±14	202±7
	5	18.9±0.4	15.3±1.4	400±15	773±43	168±15	200±18
	10	18.7±0.8	13.6±1.2	392±18	738±44	167±15	172±34
	30	18.9±0.8	15.9±1.8	393±25	759±41	180±12	186±13
	60	21.4±1.7	17.6±1.5	400±22	781±30	193±20	213±12
A3	0	17.1±1.6	14.7±1.6	369±15	786±36	177±12	196±7
	5	18.5±1.5	14.1±1.9	400±27	768±45	166±14	179±29
	10	18.0±0.8	13.6±0.9	418±16	750±43	167±15	183±14
	30	16.5±1.0	14.0±1.3	378±29	734±48	163±14	180±16
	60	18.1±0.9	17.1±1.5	386±17	764±28	183±9	200±14

### Epoxy powder

Fundamental features and tests for raw powders: epoxy powder contains some materials which are used against heat that is used as a detonator in the three layers' polyethylene coating system for the steel pipe. It must be specially formulated and designed and this is suitable for electrical applications and corrosion improvement from the coating system as well as providing maximum cathodic infinite resistance. The qualitative range of speed for all properties is listed in the table below.

### Flexibility

Flexibility should be measured in accordance with DIN 53152. The amount of different types should be smaller than 5 mm.

### Hardness

The hardness of epoxy raw film should be more than 85 when the test is performed according to DIN 53155 standard.

**Table 4.** Effects of irradiation on gas and water vapor transmission through multilayer films (2)

Material	Dose (kGy)	Oxygen (Cm <sup>3</sup> m <sup>-2</sup> day <sup>-1</sup> atm <sup>-1</sup> )	Carbon dioxide (Cm <sup>3</sup> m <sup>-2</sup> day <sup>-1</sup> atm <sup>-1</sup> )	Water vapour (Cm <sup>3</sup> m <sup>-2</sup> day <sup>-1</sup> atm <sup>-1</sup> )
A1	0	2693±71	10572±235	1.4±0.1
	5	2730±24	10883±286	1.2±0.1
	10	2892±176	11268±685	1.1±0.2
	30	2617±77	10359±396	1.1±0.1
	60	2799±86	11226±320	1.1±0.1
A2	0	2814±52	11156±308	1.0±0.2
	5	2791±153	11122±512	1.1±0.3
	10	2747±162	10998±688	1.1±0.1
	30	2888±136	11252±659	1.3±0.1
	60	2883±48	11632±292	1.5±0.1
A3	0	2640±38	10364±212	1.4±0.2
	5	2690±78	10800±325	1.5±0.1
	10	2704±109	10850±489	1.4±0.1
	30	2769±101	11030±456	1.6±0.1
	60	2747±89	10912±398	1.4±0.2

**Table 5.** Qualitative range of speed for polyethylene properties (3)

Property	Unit	Test method	Typical value
Gloss at 60° angel	%	DIN 67530	65±5
Gel time	sec	DIN 55990-T8	43±10
Density	g/cm <sup>3</sup>	DIN 55990-T3	1.5
Particle size	%	DIN 55990-T2	90 between 10 to 80 microns
Moisture content	% weight	Acceptable method to company	0.5 Max
Shelf life at 30 °C & %60 humidity	Month	---	12 Min.
Theoretical coverage	g/m <sup>2</sup>	Acceptable method to company	90 g for 60 microns DFT (Dry Film Thickness)

### Pressure resistance

The pressure resistance from the epoxy film should be minimum 120 kg/cm at 20 °C according to ASTMGH test method (with a panel thickness of 3 mm).

### Second layer

The second layer polymer creates adhesions between layers 1 and 3 and should be consistent with both layers. The minimum thickness should be between 160 and 200 microns. The thickness may increase or decrease in its range with customer agreement, but minimum thickness should be considered safely and the results of the relevant tests should be satisfactory (15).

Note 1: The copolymer film (the primary adhesive layer) is finitely used between the epoxy mixed layer and the polyethylene layer.

**Table 6.** Minimum Coating Thickness in Millimetres (3)

Pipeline diameter (mm)	Minimum coating thickness (mm)				
	PP	PE	FBE	Adhesive	
				Total 3-layer PP	Total 3-layer PE
≤ 100	1.3	2.0 0.2	0.3	1.8	2.5
> 100 and ≤ 250	1.5	2.2 0.2	0.3	2.0	2.7
> 250 and < 500	1.7	2.4 0.2	0.3	2.2	2.9
≥ 500 and < 800	2.0	2.7 0.2	0.3	2.5	3.2
≥ 800	2.0	3.2 0.2	0.3	2.5	3.7

**Table 7.** Physical Properties of Adhesive (5)

Property	Unit	Test method	Value
1) Density	g/cm <sup>3</sup>	DIN 53479	65±5
2) Melting index (2.16 kg/190°C)	g/10 Min	DIN 53735	43±10
3) Elongation	%	DIN 53455	1.5
4) Melting point	°C	DSC (differential scanning calorimeter)	90 between 10 to 80 microns
5) Co monomer content	%		

### Third layer

The polyethylene coating must be formed in this layer. The thickness must be uniform across the tube and the total minimum thickness must be acceptable. Pigments and additives may be based on polyethylene and provide all the details requested by coating. The pigments should be distributed uniformly. When additives and pigments are added, connections and required details should be in ideal form.

### Advantages between second and third layer coating

1. Additional adhesion and chemical resistance properties are determined by the limitation of the epoxy mixing (first layer-corrosion protection).
2. The physical and chemical force is obtained by corrosive formed copolymer. (Middle layer) and polyethylene (upper layer).

The process of burning tubes at the primary stage is for:

- ✓ Surface pollution removal (salts, soil, plants, oil, other pollutants)
- ✓ The layout of the layers decreasing

- ✓ Moisture removal

### Materials

- ✓ The fresh air with high pressure for salts and soils removal.
- ✓ Hydrocarbon solvents, a family of toxic and flammable and fragrant hydrocarbons or minerals) for organic pollutants removal.
- ✓ Heat the surface layer for moisture removal and burning organic pollutants in dredging up to 75 degrees centigrade.

**Table 8.** Other products with adhesive top-coat polyethylene (7)

Epoxy primer (Manufacture)	Adhesive co-polymer (Manufacture)	Adhesive co-polymer (Manufacture)
BASFOX PE-50-1081 (BASF)	LE149 V	YUCLAIR ET509B (SK Crop.)
EP-971197/EP-F-2001 (Jotun) Scotchkote 228 (3M) Karumel EX 4413 (KCC) Eurokote 71441 (Elf-Atochem)	LE200 T  LE100 A	HE3450, ME6060 (Borealis) Sclair 35BP, 35BPM (NOVA) Lacqtene 2006 PBK 35 (Elf-Atochem) Lupolen 3653 DSW (Basell)

### Cleaning sand and sticking pebbles with air

One of the purposes of cleaning the tubes is obtaining a clean steel layer with degree 2½ SA and a pattern for inhibition with the depth profile ranging from 25 to 80 micron. Cleaning with air may eliminate the contamination of the pipe but crushing (pebbles and gravel) can be used to remove contaminants from the pipe layer. The temperature of the tube layer should reach about 200 to 220 degree centigrade. The upper layer temperature should not exceed 270 degrees centigrade. In fact, contamination can occur at temperatures up to 270 degrees centigrade (16).

### Final stages of the pipe

All pipes are cleaned for connection and welding. A longitudinal rotary detergent (maximum 150 mm) completes the removal of the tube coating. The steel tube with a new polyethylene coating with excellent properties for the use of pipeline pipes was developed at 80 degrees centigrade. Various tests included abrasion resistance, piping tubes had been done that has been obtained the following results:

1. Polyethylene coating has been recently developed with excellent mechanical-physical-chemical properties and adhesion was displayed at 80 degrees centigrade.
2. The mixture with special stabilizer anti-oxidants, for polyethylene coatings, proved that they are durability at temperatures above 80 °C in mild acceleration tests.
3. The coating is reinforced with the adhesive of a strong epoxy at high temperature, which produces a waterproof layer on zinc (17).
4. Steel tubes were fabricated by a polyethylene coating that showed excellent resistance to corrosion with piping tests for 3 years at 100 degrees centigrade.

**Table 9.** Shows the repairing procedure of damage polyethylene coating (6)

Portion of damage	Size of damage	Repairing method
Pipe body	Small (Depth≤1 mm) Small (Depth>1 mm) Middle (Length≤100 mm) Large (Length≤300 mm) Large (Length>300 mm)	Remove the damage with grinder or emery paper Embedding method (Polyethylene stick) patch method Apply the anti-corrosion tape with a ½ lap Heat shrinkable tube is centered over damaged area and apply heat the tube with burner
Pipe ends	Small and middle Large	Anti-corrosion tape Heat shrinkable tube

**Table 10.** Properties of coated materials (4)

Item	Test method	Units	Properties of coated material
Density	ASTM D 1 505-67	g/cc	0.950-0.955
Melt flow index	ASTM D 1 238-65T	g/10min	0.18-0.22
Softening point	ASTM D 1 525-65T	°C	120-125
Melting point	ASTM D 2 117-64	°C	125-130
Brittleness temperature	ASTM D 746-55T	°C	<-80
Disruptive voltage	ASTM D 149-64	Km/mm	<35
Hardness	ASTM D 2 240-68	Shore D scale	60-65
ESCR <sup>2</sup>	ASTM D 1 693	F <sub>50</sub> hour	>1000

The underground pipelines of new phase wells have cool tar coating or polyethylene tapes from the Al-Tene and Al-Polykan type that corrosion has not been observed if the coating is correctly applied. Underground pipeline corrosion is one of the major problems, which the strategic industries of petroleum and gas and petrochemicals are facing with. Whereas the pipelines play a vital role in these industries, protecting and controlling of these structures is critical. Corrosion damages in steel and other coated metals, which occurs as corrosion under coating when the insulation is adjacent to moisture. It can also endanger personnel and installations safety, as well as resulting in a lot of maintenance costs and stops being produced. Insulation and coating of pipes and reservoirs are carried out to prevention; maintain temperature, process stability and optimal energy

consumption. However, dry and wet cycles of under-insulation material can provide the initial conditions for stress corrosion cracking or pitting corrosion.

### **Undercoat corrosion mechanisms**

Undercoat corrosion begins in the presence of water and oxygen. When water and oxygen are present on the metal surface, corrosion occurs due to metal dissolution (anodic effect). This chemical process is balanced by reducing oxygen. Undercoat corrosion rate depends on insulation type, the availability of oxygen, the amount of oxygen available in water, temperature, and the thermal properties of the metal surface, and dry or wet conditions of the metal surface. In the absence of oxygen, corrosion can be discarded. Although carbon steels and low-alloy steels have the lowest corrosion rate in alkaline environments, but chloride ions  $Cl^-$  cause localized pitting in the under coating. If sulfur and nitrogen acids, which have acidic properties, can penetrate into the insulation through impurities in the weather, or if the water had acid properties, the general corrosion will be occurred. Sometimes, weather impurities, especially nitrate ions ( $NO_3^-$ ), because an external stress corrosion cracking (SCC) under coating of carbon steels or undisturbed low-density alloy. The above phenomenon is especially considered more when dry and wet process of the environment increases the concentration of impurities.

### **Conclusion**

#### **Coating effect**

Corrosion is possible under a variety of insulators. Type only plays in speed and quality. The main effect of coating in this type of corrosion is providing appropriate circular space for accumulation and remaining water. Water can be supplied from external sources of rain or liquids from the condensate. The chemical composition and coating properties also contribute to corrosion. The coating material can absorb water and provide a suitable aquatic environment for electrochemical reactions. In addition, the chemical compounds inside the coating such as chlorides and sulphate can play an electrolyte role, which accelerates corrosion (18).

#### **Temperature Effect**

Surface temperature also covers an important dual role in the incidence of corrosion phenomena. The corrosion control of under warm coatings is much more complex than the cold coatings. The effect of this phenomenon is the evaporation of water under insulation and increasing the concentration of impurities in water. In closed systems, the increase in temperature has accelerated

the rate of electrochemical reactions that increase the rate of corrosion. In open systems, increasing the temperature can increase the corrosion rate. But in open systems, the increase in temperature can evaporate the water, remove the corrosive environment, thereby reducing the corrosion rate. It also reduces the high temperature of the protective coatings.

**Table 11.** Test methods and requirements (1)

Test/inspection	Test methods and requirements
1. Surface preparation	1. Visual inspection 2. Acceptable limit: as specified in 7.3
2. Coating thickness	- Electro-magnetic thickness gage is used - The gage shall be calibrated daily with the standard calibrated plates - Min. requirements: As specified
3. Porosity	DIN 30670 No defect at 25 Kv
4. Adhesion	DIN 30670, Method 1 Acceptable limit: min 23 °C 8 Kg/cm min 80 °C 2 Kg/cm
5. Impact resistance	DIN 30670 Acceptable limit: 5 Jul/mm
6. Elongation	DIN 30670 Acceptable limit: Min. 200% for extruded coating
7. Indentation (hardness)	DIN 30670 Acceptable limit: 0.3 mm
8. Thermal cycle resistance	-30 °C 1 Hr - 1 cycle: +60 °C 1 Hr Number of cycles: 100 Acceptable limit: No crack
9. Environmental stress cracking resistance	ASTM D 1693 Acceptable limit: No crack after 300 Hr
10. Thermal aging	DIN 30670 Acceptable limit: ±35% change in melting index value
11. Specific electrical	DIN 30670 Acceptable limit: $10^8 \Omega \text{ m}^2 \text{ Min}$
12. Cathodic disbanding	ASTM G8 Acceptable limit: 5 mm

### Surface tension test

This test should be done 3 times within 8 hours of product change and transformation. The test should be done in the room temperature and two objectives of the pipe coating layer and its check are discussed with the items in the table above. The corrosion of the pipe coating layer causes the equipment to explode. Therefore, it should be returned to painting and coating if the process is not completed so completely. In this case, pipe should be checked two successive times. If this condition is resolved, the pipes coating process will be stopped for full investigation after six times. This should include checking all previous pipes with the priority of more important pipes (19).



**Table 12.** Coating of butt joints-material application charts (8)

Existing coating	Butt joint	Existing coating
FBE	FBE	FBE
MCL	MCL	MCL
FBE	MCL	MCL
CTE	MCL+TAPE or H-TAPE	FBE
CTE	MCL+TAPE or H-TAPE	MCL
CTE	TAPE or H-TAPE	CTE
PE	TAPE or H-TAPE	FBE
CTE	TAPE or H-TAPE	PE
PE	TAPE or H-TAPE	MCL
PE	TAPE or H-TAPE	PE

Systems of transferring pipe lines and oil and natural gas in Iran and other places in the world, usually are very long and has many branching, disabling of these lines could have set serious and effective problems on the environment, economic and society. As the result, it's necessary that after install and starting these pipe lines, accurate operation should be perform for the purpose of awareness of disabling manner and intensity of these pipes and probable repair that's needed. On the other side the process of repairing and replacing of damaged pipe lines is very time consuming and costly. So use of polyurethane covering with 100% solid and correction of quantity risk of disabling pipe lines which damaged cause to economic saving of time, polyurethane covering as a polymer material that today is completely replacing polyethylene covering, has many benefits like chemical and mechanical superior properties.

Corrosion has been taken from "corrodors" latin word and in technical term, each kind of metal decreasing arising from electrochemical process is corrosion. Costs that corrosion damages caused in industrial countries yearly is 4% of national impure income. Which considerable amount of that allotted to pipe lines and related equipment's? In corrosion assessment should attend to two elements: first, the type of materials which is chosen for the pipe line and second environmental condition of pipe line from the viewpoint of corrosion. Although other mistakes during the process of choosing materials, designing, making, installation, starting and protecting can cause to create a suitable environment for corrosion or decreasing resistance against its threat. Corrosion phenomenon is one of the basic subjects in industrial field. Corrosion phenomenon is mooted in all industries and there is no limit about this matter. Today metal corrosion in Iran like other countries of the world cause to fade of equipment's, machines, jetties, digging equipment's, water, gas and oil pipes, energy generator powerhouses, port foundations and refineries. For this reason, each year, enormous quantities of country capital are wasting. Then, recognition of corrosion and related

experiments and ways of protection and applying these ways cause to decreasing of losses and can be counted as an important step in direction of industry self-sufficiency, but by attention to this matter that in our country, oil industry is counted as the oldest and basic industries, the importance and the role of corrosion in oil industry in more tangible. Corrosion phenomenon and campaign with that now obtains its place in oil industry. We hope that organizing of corrosion management in this ministry has the rightly effect on plan of corrosion phenomenon in oil industry and other country industry organs. About economic assessment and corrosion damages, some statistics and numbers presented from some advanced industrial countries. Statistics of industrial countries indicate to 4-5% of national impure production. Some of them are pointed: corrosion loss in USA in 1994 reported 300 million \$ and it is estimated that this number arrives to about 400 million \$ in year. In German in 1994, 117 milliard Mark reported for corrosion loss. In Iran, by estimating, number of financial loss arising from corrosion is about 12500 million Rials in 1997. By suitable programming we can decrease this number 25%. Environment is a phenomenon that today is much mooted. Is there any relation between corrosion and environment? Explain yes, corrosion phenomenon cause to wasting of material, energy and capital and one of the results of corrosion is environment pollution. For example, a pipeline leak due to corrosion causes oil entering the ecosystem which damages the environment. But it should be noted that while preventing, the environmental parameters should be considered. For example in the use of corrosion inhibitors as corrosion catalyst materials, we should be careful that some of them like chromate, zinc, polyphosphate, nitrate and nitrite can damage environment themselves, so their use should be monitored carefully, because sinking and entering of these materials can have certain poisoning effects on aquatic animals of ecosystems. Although chromate is the most effective inhibitor material which is available today, it has use restrictions because of polluting the environment.

In production, installation and exploitation process of gas and oil pipe lines, related defect due to use of primary materials with low quality, lack of correct installation, changes of around environment of pipe line and also harmful materials exist in oil and gas causes to firmness decreasing, useful age of pipe line decreasing and even decreasing of safety properties. By attention to performed researches, the most important negative elements that effect on the proficiency of oil pipe line include the below cases:

- I. Corrosion, lack of correct installation, damages and external forces, that all of these elements cause to fade of material quality used in pipe line.
- II. Underground events like earthquake that these cases effect on the pipe line hardly and suddenly and can change natural environment around the pipe line.

### III. Bad quality of materials used in instruction of pipe line.

Despite the existence of isocyanine groups in formulation of polyurethane 100% solid, this material as a compatible product with environment doesn't causes any damage to environment and workers that use suitable safety equipment's. Polyurethane 100% solid doesn't create any pollution in any steps of production, storage, transferring and usage. Some of polyurethane 100% grades have confirmation of use in contact with water and nutrition plants. The result of gas analysis on the polyurethane 100% is reported that the percent of HCN ascending from polyurethane 100% in blazing condition is zero.

### Suggestion

(A) Prevention methods in design and construction:

1. Use of coverings with high firmness and stickiness like 3 layer polyethylene covering, melt epoxy covering and polyurethane covering.
2. Full caution when using pitch coverings (oil and coal tar).
3. Not using plastic band coverings as the main covering.
4. Assist above cases for scum coverings.
5. Cleaning the surface of pipe as the 2.5 SA standard and complete elimination of factory oxide layer.
6. Decreasing the Face Reinforcement in factory in order not to have any empty space between covering and pipe.
7. Full caution when using spiral weld pipes because of long weld line considering probable risks of stress corrosion.
8. Designing output pipes of compressor stations until the first valve after the station or until the first 20 kilometres after station with the same class in order to decrease pipe stress and to eliminate stress corrosion.
9. Using the temperature under 50 °C for output gas of station in order to decrease damages due to stress corrosion.

(B) Prevention methods in operation steps for pipe lines which stress corrosion cracking has been seen or is predicted in them:

1. Decreasing internal pressure of the pipe.
2. Leak detection each 6 month on transferring pipe lines with bellow features:
  - ✓ Pipe covering should be cold plastic and minimum 10 years should be passed from its construction

- ✓ Output of compressor stations till the first valve after station or the first 20 kilometres regardless of covering type
- 3. Discussing soil conditions of humidity, type, mixture, electrical resistance, pH.
- 4. Checking cathodic protection condition of pipe line.
- 5. Checking pipe covering and if necessary digging on the pipe in some spots every 1 or 2 years.
- 6. Doing static pressure experiments and repairing damaged spots.
- 7. Using ultrasonic smart ball equipped with crack detection device in order to determine the scope and the exact position of cracks.
- 8. Surveying the corrosion products composition made on the pipe.
- 9. Surveying the acidity strength (pH) statics under the pipe covering.
- 10. Non-destructive inspection on pipe with manual ultrasonic devices.
- 11. Cleaning the pipe surface and placing the new cover.
- 12. Changing the pipe.

Generally, corrosion costs include high capacity of the national capitals in countries. By taking a look at experience of other countries we can see that many countries now think about suitable arrangements in order to contrast with damages due to corrosion. A basic need that corrosion experts of America considered is performing studies for estimating metal corrosion costs on the economy of America and compiling of a strategy for decreasing corrosion costs. Therefore on the basis of performed conversations between members of congress and transferring ministry, a correct plan for corrosion costs in transferring (NACE) American society of corrosion engineers in 21 century presented, which has been accepted by the congress in 1998. Most of experts of our country believe that first of all we need a basic movement in the field of providing complete formal statistics in the corrosion field in order to determine the dimension of corrosion in all industries.

1. Corrosion is one of the non-avoidable problems in oil industry.
2. Soil properties, especially microorganisms activity in comparison with other elements increases the corrosion speed and destroys the pipe line confidence ability, so this element should be noticed in direction of performing reserved bilateral actions.
3. For the purpose of firmness predicting and retain life time of pipe line, some parameters like disabling probability, corrosion distribution and confidence ability should be considered seriously.
4. Use polyurethane covering for oil industry steel pipes that with high corrosion resistance, prevents demolition of these equipment's.
5. Using polyurethane is not dangerous and is completely safe.

6. By attention to the result of the performed experiences, this covering corresponds to the new standards of DIN, ASTM and protects pipes.

### Conflict of Interest

We have no conflicts of interest to disclose.

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