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The Effects of Corrosion Problems on the Performance of Oil Wells Operated with Electrical Submersible Pumps: Lessons Learned

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Abstract
To diagnose the corrosion reasons in the most suffered oil wells, this study gathered an integrated field database for the oil wells operated with electrical submersible pumps (ESP) and had significant corrosion problems. In this database, 255 workover operations with rig conducted in super giant oilfield, located southern of Iraq, were evaluated and detailed for the production status of the target wells prior to the workover process and after the workover operation during the period (2015–2017). The gathered database helped to address the main causes of the corrosion in the workover wells and clearly explained the effect of corrosion on the failure of ESP wells in the field. The statistical analysis for the gathered database showed there is a strong correlation between the corrosion rate and the increasing water cut from the Main Pay wells. In addition, high-rate oil wells are observed to have the quickest corrosion failures. However, the plots of the statistic corrosion map do not seem to indicate a specific area or reservoir section but rather a field wide challenge. Interestingly, the CO_2 corrosion due to the turbulent flow regime right above the ESP was the main reason for the failure of ESP wells caused by the induced holes in the tubing string. This study found that such corrosion issues can be mitigated before they occur in more producing oil wells by installing 13% Chrome metallurgy (CR-L80) tubing string in all Main Pay wells instead of using L80 alloy steel tubing string. Thus, such practice will reduce the cost, time and number of workover operations. Based on the scale of this constructed field database, this investigation also showed that the extra cost due to purchasing the 13% CR-L80 tubing would be offset if the tubing failure is mitigated in only 2 ESP wells.

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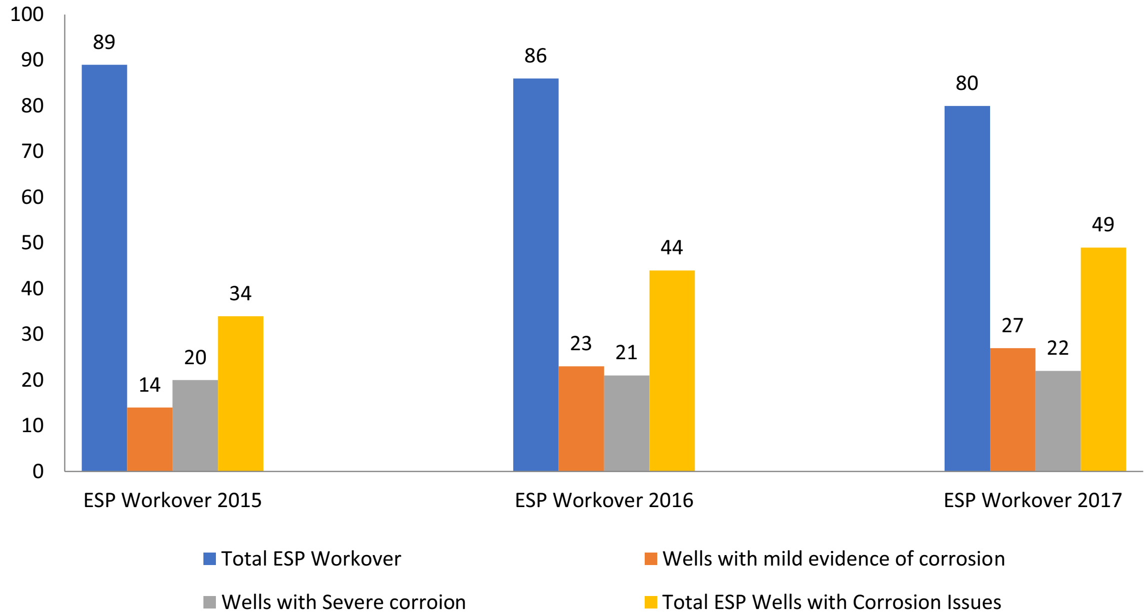
Graphical Abstract

ESP corrosion damage during (2015–2017) reported by the inspection process of pulled tubings



Keywords Corrosion · CO_2/H_2S corrosion issues · Oil and gas · Alloys · Corroding agents · Oil wells · Well completion

1 Introduction

Corrosion can be defined as the reaction between the material and its environment which lead to a destructive attack on the material body [1]. Such a destructive attack, corrosion, could lead to a significant damage in the oil well production system as well as the transportation facilities [2]. Corrosion is considered as one of the most common problems in the oil and gas industry, especially in the completion strings of the production wells. The oil and gas wells operating with artificial lift techniques could be the most corrosion-suffered wells. Such severe corrosion leads to holes in production strings, failure of electrical submersible pumps (ESPs), loss of production and/or an ESP fish.

It is known that the corrosion can occur if numerous complex conditions are met in oil and gas production, processing and pipeline systems [3]. The corrosion can be formed among three parties which are an anode, a cathode and an electrolyte where the anode is referred to the corroding metal, the electrolyte is the corrosive medium which transfers the electrons from the anode to the cathode, and the cathode composes the electrical conductor in the cell which is not consumed in the corrosion process [4]. Crude oil and natural gas contain a lot of impurities and chemical agents which are considered significant corrosive materials [1]. Carbon dioxide (CO_2), hydrogen sulphide (H2S) and free water are good examples for the highly corrosive media in the oil and gas industry [5]. Therefore, the internal and uniform corrosion induced by CO_2 and/or H_2S gases in the inner streams of the petroleum systems is the most inherent concern of the operators regarding the carbon steel pipelines selected for any oil production process [6]. The continuous motion for CO_2, H_2S and free water throughout the oil and gas pathways can over time degrade the internal surfaces of such pathway components due to the corrosion effects [1]. Such degradation processes in the oil and gas wells can occur due to changes in fluid compositions, souring of wells over the period and changes in operating conditions of the pressures and temperatures [1]. The loss of mechanical properties like strength, ductility, impact strength and so on would be resulted due to the material degradation caused by the corrosion process. The continuous loss for the core of the component materials would result in reducing its thickness, which leads to ultimate failure at certain conditions. At a certain point, the operator will face a completely break down component and the assembly will need to be replaced while the oil/gas production is stopped. Such a serious impact for the corrosion process has become a challenging problem for global oil and gas industry components and facilities [2].

The corrosion has not only impacted the oil industry but also the entire modern society due to its challenging problems to the different types of industries globally. One of the most priorities for any industrial design is to take into consideration the effect of corrosion on the life span of the equipment [1]. Any industry design, which could not handle the corrosion threat in the proper way, could cost several billions of dollars. In the same trend, different reports around the world have confirmed that some oil companies had their pipeline ruptured due to corrosion which led to oil spillages and created environmental pollution [7]. It has been estimated that the costs attributed to corrosion damages from their different kinds to be of the order of 3% to 5% of industrialized countries' gross national product [8]. In the oil and gas production industry, the total annual corrosion cost is estimated to be $1.372 billion, distributed among surface pipeline and facility costs which are $589 million, downhole tubing expenses which are $463 million annually, and another $320 million in capital expenditures related to corrosion [9]. Corrosion is a phenomenon that cannot be prevented or eliminated altogether [10].

In this paper, we highlighted the problems of corrosion in the production tubing and the reasons that led to the failure of electric submersible pumps (ESP) based on real field database. In addition, this study estimated the economic cost of such failures caused by corrosion. This research also provided the technical recommendations for minimizing costs associated with the corrosion.

2 Background

Rumaila oil field is a supper giant oil field in southern Iraq, located 50 km west of the city of Basra and 32 kms north of the Iraq–Kuwait border. Rumaila fields are divided into two parts: North Rumaila and South Rumaila adjacent to Kuwait. The oil production process from the Rumaila fields is managed under the supervision of Basra Oil Company. The new technical service contracts were signed in 2009 between the South Oil Company owned by the Iraqi government (SOC), BP, CNPC and SOMO. This resulted in the establishment of the Rumaila Operating Organization. Rumaila is currently produced from several layers including the Main Pay, Mishrif, upper shale layer and the Fourth Pay. In this study, we will focus on the Main Pay layer. Rumaila field suffers from a major technical issue, which is the corrosion issue. That issue causes damage to tools, equipment and failure of ESPs due to the tubing damage. Re-installations cost for ESP & new tubing was annually estimated to be at millions of dollars digits. The process of corrosion may lead to the suspension of production stations and the failure of ESP wells that produce oil and thus lead to a significant loss of production.

The metallurgy strategy in Rumaila has been to run a full string of 13%Cr tubing on ESP wells. However, in some other wells, running only 5jts of 13%Cr right above the ESP pump was suggested to reduce the completion cost [11]. Such plan led to significant corrosion problems. It has been observed that the wells, which have received full strings of 13% Chrome during the previous workover operations, to date, have displayed no signs of tubing corrosion. On the other hand, the wells which have received only 5 joints of 13% CR-L80 reported many corrosion problems associated with L80 alloy steel joints. The L80 alloy steel joints were corroded where holes in the tubing (HIT) have ceased production which equates to more than ~ 16 mbd. The logging tools which run in such wells showed a high percentage of wall loss on the carbon steel joints while zero on the chrome ones. As the water cut in the field continues to increase so does the level of corrosion. An increase in corrosion ratio from 2015 to 2016 was noticed on Carbon Steel tubing strings which were pulled from the ESP producer wells. The majority of the corrosion/erosion issues are concentrated in high water-cut Main Pay wells which are flowing more than 2000 bpd. In 2016, 45 days rig NPT was associated with fishing/pulling corroded tubing.

The selection of metals suitable to perform a certain task must be done according to certain criteria considering the mechanical and thermal properties [12]. Then, the environment which will be exposed to these minerals should be also studied. For instance, using low-alloy steel tubing string (Alloy Steel L80) in Rumaila oilfield is appropriate in terms of cost, durability, weight and thermal stability [13]. However, this cannot be a good choice if accompanied by the process of oil production which releases highly corrosive gases such as (H_2S) and (CO_2). Such process would lead to the reaction of the tubing alloys with these gases gradually, resulting in the failure of production tubing and thus failure of ESP. Therefore, corrosion is a real issue in the Rumaila oilfield, causing an annual damage to millions of dollars' worth of tools, equipment and installations. The process of corrosion may lead to the suspension of production stations and the failure of producing wells and thus loss of production. Based on failure rate that was estimated depending on this database, around 70% of all ESP wells require a full string of 13% CR-L80 tubing string. The terms of reference for this corrosion study highly recommend to increase the use of 13% CR-L80 tubing strings in Rumaila oilfield to mitigate the corrosions issues.

In this study, we tried to address the major type of corrosion that causes ESPs to fail and clarify the impact of corrosion on the cost of replacement and production lost. Some people may think that when the word 'cost' is heard only from finance viewpoint, it is possible that the total loss due to corrosion is about 15% of the operational cost of the field. As the cost depends not only on the replacement of corroded tubing with new ones, but also on indirect costs as well as the effect of corrosion on the environment side, and thus trying to preserve the environment and related wells in the field, the corrosion problem is much more than predicted in many scenarios. The aim of this paper is to find an optimum solution that keeps ESP in a good technical condition for the longest possible period by lowering the cost, reducing the maintenance and minimizing the replacement of the ESP and the production tubing.

3 Corrosion Study Database for Workover Wells (2015–2017)

For identifying the real cause behind the increase in the corrosion of pulled production tubing string, a corrosion strategy was suggested to start up with building a proper corrosion study database for workover wells (2015–2017). It was necessary to re-study the workover operations for ESP wells in detail by evaluating the well status before rig workover operation and after rig workover operation. In this database, 255 Rig workover operations were studied and evaluated. The prepared database was passed through different stages to be meaningful. Therefore, the following configuration methods were suggested to obtain the results of this investigation:

- Define the conditions under which 13% CR-L80 will be used in Rumaila oil field.
- Then, review the conditions of tubing upon retrieval from the well and compare against production conditions.
- Analyse production data to understand and predict the service life based on water cut, gross liquid rate and CO_2/H_2S concentrations.
- Develop a database for identifying corrosion trends over the 2015-2017.
- How much reduction in the overall cost by using more 13% Cr tubing was estimated.
- How the improved 13% CR-L80 tubing handling & handling procedures have an impact to maximize re-use of recovered 13% CR-L80 tubing.
- Compare the degree of corrosion against the production conditions.
- Maintain the corrosion database which can be used to quantify the problem as the year progresses.
- Implement the wellhead sampling and well test plan to characterize the produced fluid throughout ESP producer wells.
- Select candidates post workover for full-length EMI inspection to determine the effective wall loss
- Compare the results of the inspection against parameters such as the duration in the well, the flowing duration and produced fluid characteristics.

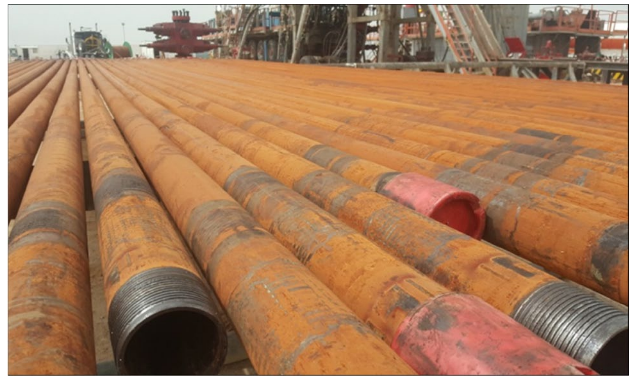


Fig. 1 Pulled production tubing (3 1/2 "9.2, L80) as an example of regular corrosion

- Implement a strategy which defines when 13%Cr tubing can be re-used and at which point is no longer cost effective.

All the previous points led to the development of an optimal solution to reduce the corrosion rate in the production tubing string by defaulting run 13% CR-L80 metallurgy justification for Main pay producer wells. As a result, a significant elimination has been observed on the failure of ESP due to corrosion.

4 Major Types of Corrosion Noticed on the Pulled Production Strings

The impact of corrosion on the surface of the metal takes different forms depending on the nature of this corrosion and conditions of the environment which leads to such interaction [14]. The following types of corrosion were distinguished on the pulled production tubing in Rumaila Oilfield:

4.1 Uniform Corrosion

It is also called the general corrosion, which is the most common type, where corrosion occurs on all parts of the metal at the same rate and occurs when the metal is uniformly metallurgic and structurally uniform and has equal access to all of its parts [15]. Such specifications are not existed in the real world but remain labelled as common if regularity is predominant as shown in Fig. 1.

4.2 Corrosion Caused by Carbon Dioxide CO_2

Corrosion caused by carbon dioxide (CO_2) is a serious issue in oil and gas production [16]. It is the most effective

Fig. 2 Production tubing type (3 1/2 " 9.2, L80), an example of the impact of CO_2 corrosion leading to create holes

corrosion that is noticed on pulled tubing string in Rumaila oil field as shown in Fig. 2. The presence of carbon dioxide in the produced fluids of the oil wells can lead to the sweet corrosion. The use of low-alloy steel tubing (L80) as production tubing is common in oil industry [17]. However, this type of tubing is not resistant enough to light sweet environments (i.e. with CO_2 content). Carbon dioxide corrosion is the dominant form of erosion in oil and gas production, which could be dangerous and costly if no specific control measures are taken against it [18].

Dry carbon dioxide is not an oxidant for carbon in normal well conditions; however, it becomes somewhat degraded when it dissolves in condensed or condensed water forming a weak H_2CO_3. In addition, it can lead to very high corrosion rates when corrosion becomes topical [19].

There are many ways to control the corrosion of CO_2. Among those, it can be done by addressing the corrosion environment (inhibitors) and changing the composition of the metal to improve corrosion resistance (material selection). In some cases, inhibitors cannot be used because the inhibitor efficiency is low due to turbulent flow [20]. This is the case with the production tubing as the CO_2 corrosion control method can be performed by choosing the right materials for the various oil production operations.

The Low-Alloy Steel L80 tubing string is enormously used as the most common production tubing in Rumaila oilfield because it is cheap and easy to obtain. However, the L80 tubing is not resistant enough to environments containing carbon dioxide (CO_2) compared with low-carbon steel alloy with 13% chromium content tubing string. Therefore, the metallurgical industries have developed new categories of production tubing containing less carbon with chromium content. These chrome-containing tubings (L80-Cr13%) are corrosion resistant superior to the corrosion of CO_2. This type of tubing is different from L80 production

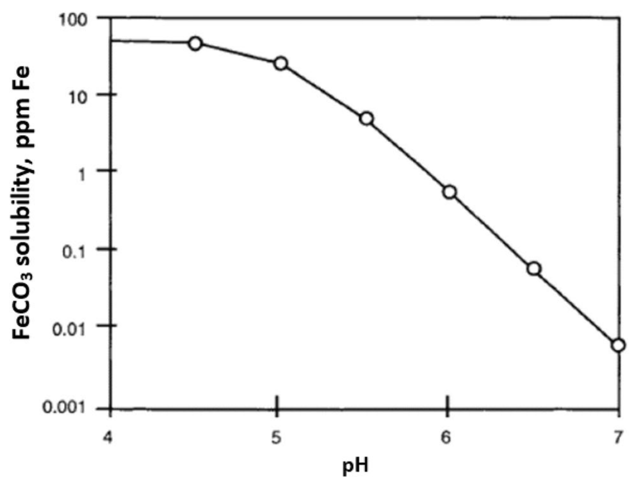


Fig. 3 Solubility of iron carbonate released during the corrosion process at 2 bar pp CO_2 at 40 °C

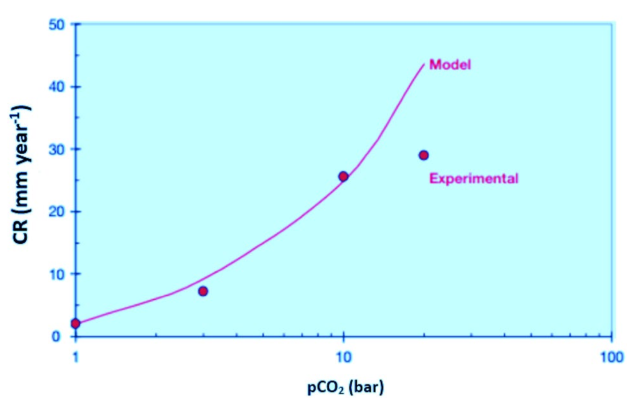


Fig. 4 Shows the effect of partial pressure (pCO_2) on the corrosion rate in range of 60–5 ℃

tubing in terms of commercial sides, which is an economic option. The use of corrosion resistant production tubing (L80-Cr13%) is not an economic justification for use in low or moderate CO_2 environments [21].

Small amounts of chromium (0.5% to 3% by weight) can improve the resistance of low-alloy alloys to corrosion in environments containing CO_2 because chromium enhances the composition of the oxide membrane. In addition, it has been shown that the addition of 3% chromium in the composition of steel can reduce the rate of corrosion by 10 times [22].

4.2.1 Factors Affecting CO_2 Corrosion

The intensity of carbon dioxide corrosion on low-alloy steel alloys is affected by several factors including environmental, physical and mineral variables. The following list shows the main factors affecting sweet corrosion:

4.2.1.1 Effect of PH on CO_2 Corrosion PH is one of the most important factors impacting the corrosion of low-carbon alloys because it affects both electrochemical reactions and has a direct impact on the corrosion rate. The typical pH in condensed water saturated with CO_2 is about 4 while it is in the range of (5–7) in stored solutions. If the pH is 4 or less (the minimum reaction of H + ions) and the partial pressure of the CO_2 is low, then the effect of the carbonic acid reaction can be ignored [23]. On the other hand, the higher the pH value, the greater the FeCO3 melting, which in turn can reduce the corrosion rate as shown in Fig. 3.

4.2.1.2 Effect of Temperature on CO_2 Corrosion When a steel alloy is contacted with wet environment of CO_2, it can form reactable carbonates [24]. At high temperatures (80° C), solubility between iron and carbon will decrease, and the scales will begin to form on the surface of the metal. The initial temperature at which corrosion begins to be effective is in the range of 70°-90° C. However, above this range of temperature, less erosion would happen [23].

4.2.1.3 Partial Pressure Effect on CO_2 Corrosion Increasing the partial pressure of CO_2 will increase the corrosion rate as shown in Fig. 4. This happens because such increase in the partial pressure of CO_2 would increase the concentration of carbonic acid, which in turn will stimulate the cathodic reaction that leads to increase in the erosion rate [25].

4.3 Corrosion Caused by Hydrogen (Hydrogen Damage)

Hydrogen damage is a form of environmentally assisted failure that results most often from the combined action of hydrogen and residual or applied tensile stress. Hydrogen damage to specific alloys or groups of alloys manifests itself in many ways such as cracking, blistering, hydride formation and loss of the tensile ductility as shown in Fig. 5. For many years, such failures have been collectively termed as hydrogen embrittlement; this term persists even though it is improperly used to describe a multitude of failure modes involving hydrogen; several of which do not demonstrate the classical features of embrittlement [26]. Hydrogen gas is an important industrial gas and is produced in the oil industry because hydrocarbons break down at high temperatures or during the oil production process. Cathodic protection processes or hydrothermal reactions are generated by the hydronium ion at the cathode and there are other reasons for the formation. The collapse is caused by the generation of atomic hydrogen from a chemical reaction. Hydrogen is a very dangerous gas because it is easy to ignite and explode. In addition, hydrogen can be released and sulfuric gas can be buried inside the oil reservoirs causing severe corrosion for these reservoirs.

Atomic hydrogen is carried through the pores of the metal, where it combines with the molecular hydrogen, which cannot get out of the pores. Over time, insufficient amounts of molecular hydrogen are trapped inside the metal, creating enough pressure to break the metal and completely collapse. The metal could be torn parallel to the surface. When the molecular hydrogen is trapped near the surface of

Fig. 5 Production tubing (2 7/8 in; N-80; 6.5 lb/ft), an example the effect of hydrogen corrosion on production tubing string

the metal, there are blisters on the surface. When the rupture is examined under the microscope, cracking occurs during the crystal groups. This is true for low temperatures. However, at high temperature, the cracks are at the limits of the crystals. At high temperatures, hydrogen reacts with iron carbide forming methane whose particles are large and cannot escape out the metal pores. This creates high pressure within the metal, which leads to cracking.

The state of hydrogen is not chemically stable. Since its chemical stability is very low, it has physiological properties. Even small amount of H_2S can penetrate the surface of the hard metal and penetrates through it or assemble inside it. Hydrogen attack is caused by exposure of steel to a hydrogen environment. The severity of the damage depends on the time of exposure, temperature, hydrogen partial pressure, stress level, steel composition and structure [27]. It is possible to prevent the hydrogen union with carbide by adding the element of chromium, nickel or vanadium and others. Therefore, most of the stainless-steel alloys resist hydrogen at high temperatures to contain the chromium element.

4.4 Corrosion on Mishrif Wells

For Mishrif formation, the strategy for tubing metallurgy selection is still debatable. To date, only 1 well exhibits premature ESP failure due to hole in carbon steel tubing. However, it is important to notice that Mishrif water cut across the field is on average low < 10% yet the H_2S & CO_2 content is on average higher than the Main pay with, respectively (150 + ppm and 1%). The produced water ion analysis, in terms of pH, H_2S and CO_2, does show the Carbon steel L80 tubing will corrode once water cut increases, yet the corrosion model does not show the 13%Cr tubing as a 100% solution. This was the conclusion because the 13% CR-L80 application in Mishrif was in the grey area because of uncertainty with pH in terms of resistance to corrosion and stress corrosion cracking. Therefore, the objective is to have a

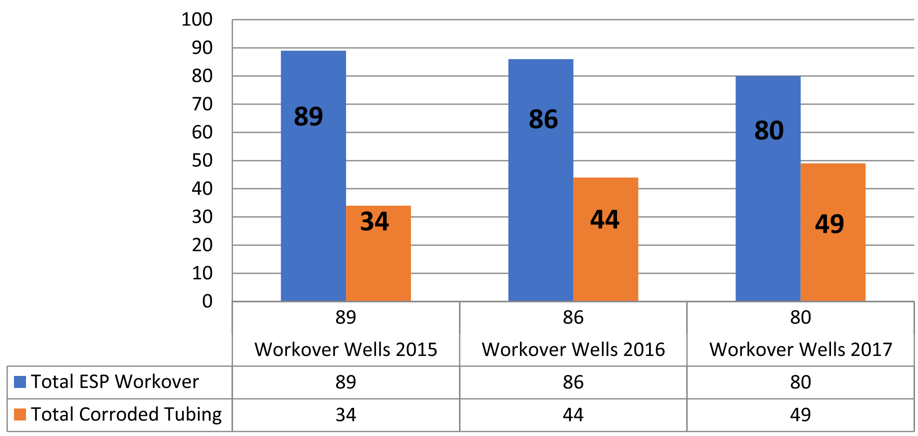


Fig. 6 Occurrence of tubing corrosion per each ESP installed in oil well during (2015–2017)

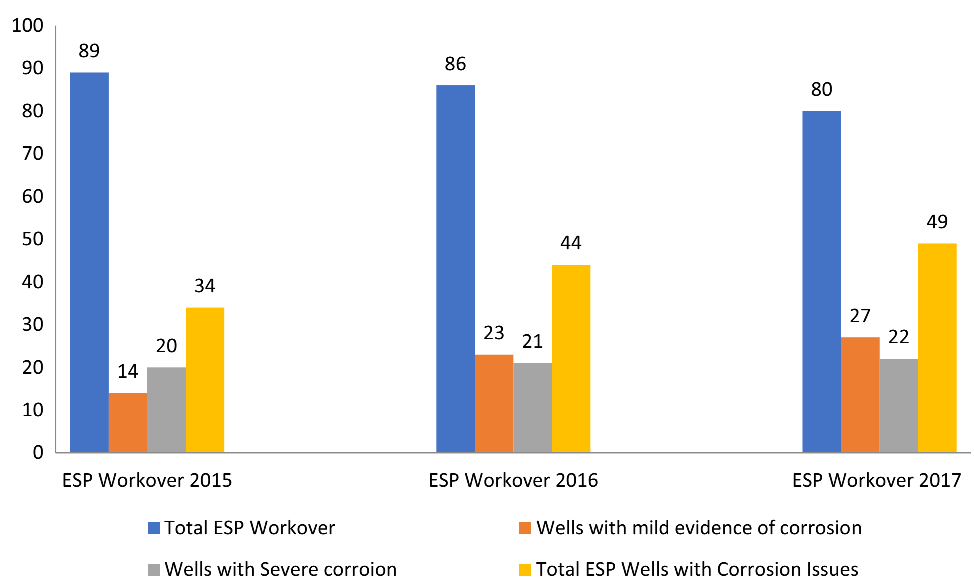


Fig. 7 ESP corrosion damage during (2015–2017) reported by the inspection process of pulled tubings

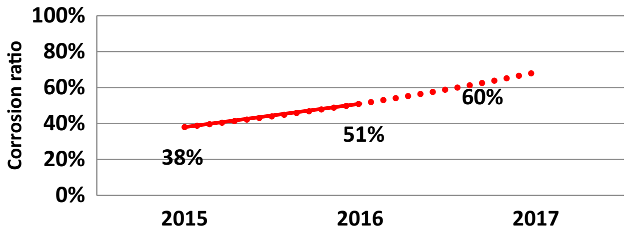


Fig. 8 The corrosion rate per year based on the number of corroded tubings per ESP wells which were undertaken workover operations

decision point by Q2 2020 so that a proactive approach could be taken as ESP installation on Mishrif is ramping up.

5 Results and Discussion

In this study, 255 rig workover operations with ESP had been studied and re-evaluated during the years of (2015–2017). The main objective was to identify the main reasons which led to create corrosion problems in the production tubing string and the failure of ESP by detecting the corrosion rate on pulled tubing string. Figure 6 shows the total ESP workover operations per year as compared with the total corroded tubing strings indicated by the inspection process during the rig workover operations. As shown in Fig. 6, the total number of ESP workover was 89 operations while the total number of the corroded tubings was 34 in 2015. This means about 38% of the failed ESP was due to the tubing corrosion issues in 2015. In 2016 and 2017, these percentages increased to 51% and 60%, respectively.

In 2015, 89 electrical submersible pumps (ESP) were installed or replaced in production wells. 28 of these ESPs found that the corrosion rate in the production tubing was low to medium as shown in Fig. 7. However, other 20 of these ESPs found that the corrosion rate in the production tubing was severe. On the other hand, 9 ESPs were failed due to the induced holes in the production tubings which are carbon steel L80 type.

In 2016, 86 electrical submersible pumps were installed or replaced for production wells. 23 of which found that the corrosion rate in the production tubing was light to medium as shown in Fig. 7. However, 21 of them found that the corrosion rate was severe. On the other hand, 9 ESPs were failed due to the induced holes in the production tubings which are carbon steel L80 type.

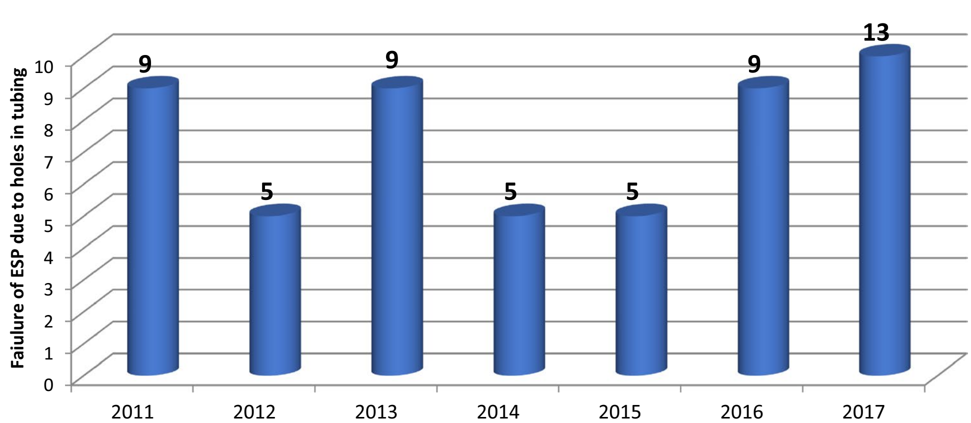
In 2017, 80 electrical submersible pumps ESP were installed or replaced for production wells. 27 of which found that the corrosion rate in the production tubing was light to medium as shown in Fig. 7. 22 of them found that the corrosion rate was severe. 13 submersible electric pumps failed due to the induced holes in the L80 production tube.

It is clear that there was an increasing trend for the severity of the corrosion rate with time in the production string of carbon steel L– 80 type per year as shown in Fig. 8**.** We noticed that the corrosion rate in the replaced production tubings was 38% in 2015, 51% in 2016 and 60% in 2017.

We can notice that the ratio of electrical submersible pumps ESP, which were failed due to the induced holes in the production tubing, has no specific trend with time during the period (2011–2014) as shown in Fig. 9. There were 9 pumps failed in 2011, 5 pumps failed in 2012, 9 pumps failed in 2013 and 5 pumps failed in 2014. However, we can notice that the ratio of electrical submersible pumps ESP, which were failed due to the induced holes in the production tubing, was in an increasing trend with time during the period (2015–2017) as shown in Fig. 9, where 5 pumps failed in 2015, 9 pumps failed in 2016 and 13 pumps failed in 2017.

In 2016, the non-production time for the pull-out of corrosive tubing string during the rig workover operation for about 50% of wells which have ESP was 45 days per well. Corrosion caused by carbon dioxide (CO_2) is the main reason for the ESP failure due to the induced holes in the production tubing. The presence of carbon dioxide in the fluids of the oil well can lead to erosion of the metal and create

Fig. 9 ESP failure due to the tubing corrosion (holes)



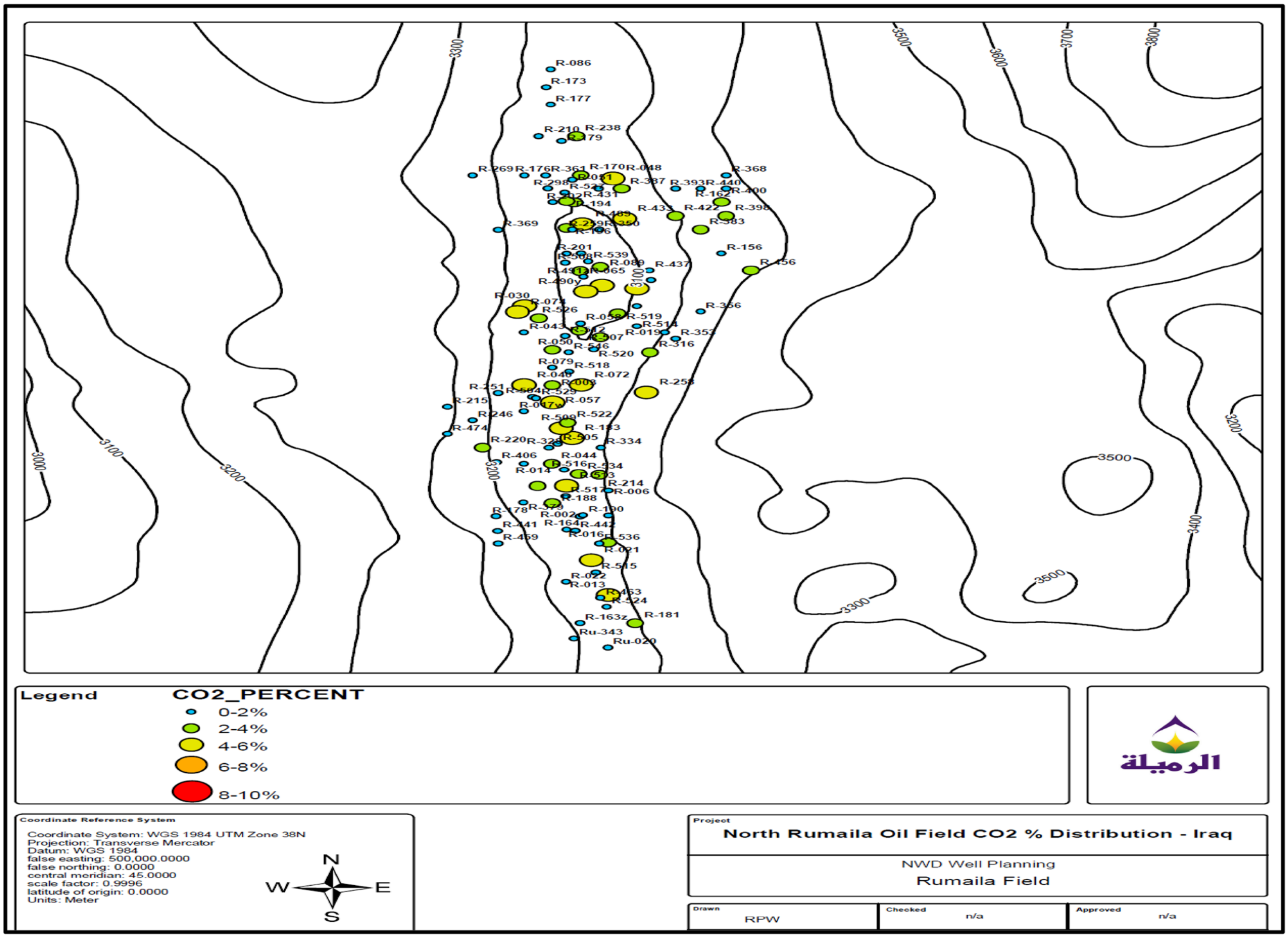


Fig. 10 North Rumaila Oil Field CO_2% distribution map

Table 1 Business case to establish a structured replenishment rate of 13% Cr tubing for ESP producer wells during a single calendar year

Approach	Action	Consequence	Severity impact	STB lost/ deferred $ MM	Impact $ MM	Total impact $ MM
Do Nothing	continue with current replenishment rate	Failure of 10 ESP wells due to the induced holes on tubing body caused by CO2 corrosion	One well lost, needing replacement drilling (50%)	1.8	19.7	75.2
			Deferred production, 9 wells waiting on a rig for 4 months	2.7	54.7	
Run 13 Cr tubing string on 70% of all ESP rig interventions in 2017	Set up a replenishment rate of 1800 joints/month	Reduce failure rate to 50%	Deferred production, 4 months on 5 wells	1.5	30	42
			Additional cost of 13% Cr tubing (22,000)		12	
Added if we utilise 13 Cr tubing on 70% of the ESP WORKOVER IN 2017 ($ MM)						33.2

a hole in string. The measurement of CO_2 mole fraction in the produced fluid during the well testing process may indicate that the production tubing string is corroded or will be corroded in the near future as shown in Fig. 10. The use of low-alloy steel tubing (L80) as production tubing is common. However, this type of pipe is not resistant enough to light sweet environments (i.e. with CO_2 content).

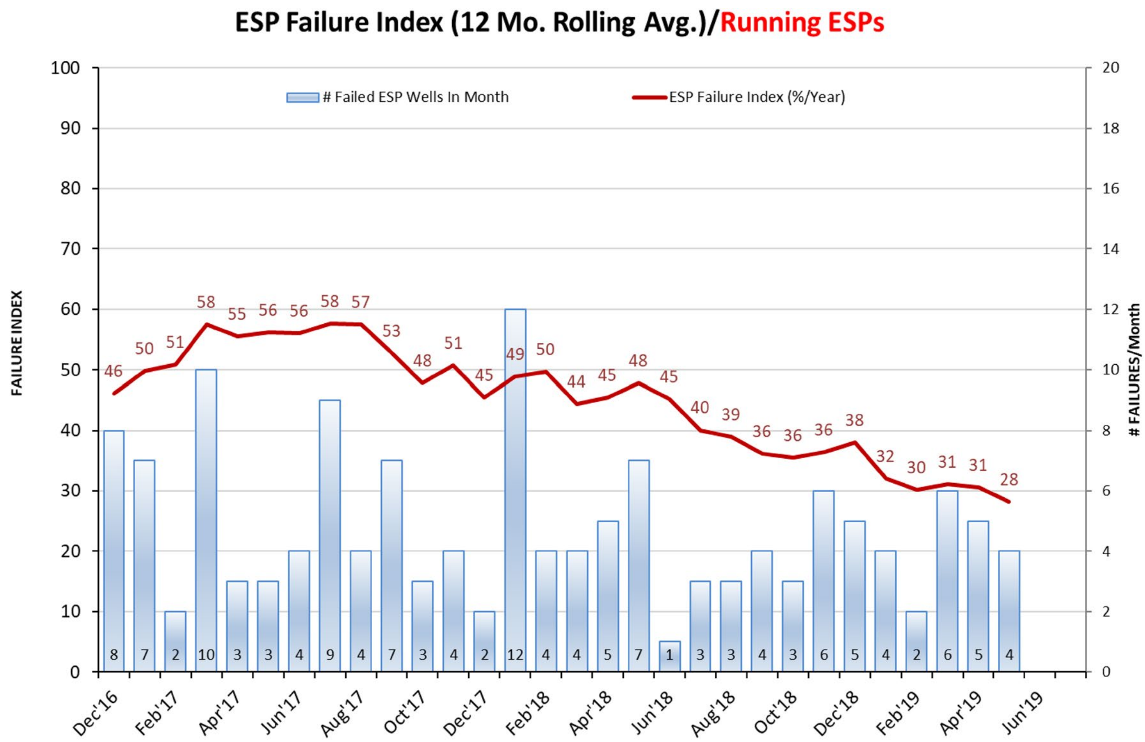


Fig. 11 ESP failure index (12 mo. Rolling Avg.)/Running ESPs

It has been estimated that the additional cost to replace two ESPs failed, because of corrosion, combined with the production loss due to the waiting time of workover operations and put the well back on production is approximately equivalent to the extra cost paid to purchase an alloy steel 13% CR-L80 chromium production string instead of installing alloy steel L80 production string. The extra cost for a whole year to purchase 13% Cr-L80 strings will be offset if we could avoid the tubing failure in only 2 wells. Table 1 shows the business case of establishing a structured replenishment rate of 13% Cr tubing for ESP producer wells. The interesting thing is that when alloy steel of 13% CR-L80 production strings were used in some wells during the previous years (2017–2019), no ESP was failed due to the corrosion. Figure 11 shows the ESP failure index (12 mo. Rolling Avg.)/Running ESPs from 2016 to 2019.

6 Conclusions

Based on field data of 255 workover operations, a comprehensive study was conducted to investigate the reasons behind the corrosion issues in ESP oil wells and how to mitigate such problems. In addition, economic calculations were performed to evaluate both the corrosion damage for such oil wells and the suggested solutions to solve it. The following conclusions can be drawn from this research:

- The statistical results showed that the increasing trend for the corrosion issues in ESP wells is strongly correlated with the average water cut produced from the Main pay wells. As far as the water cut is high the corrosion rate would increase.
- Form this study, it has been found that the oil wells of high production rate are observed to see the quickest corrosion failures.
- The statistic corrosion map plots do not seem to indicate a specific area or reservoir section of more corrosion issues but rather a field wide challenge.
- CO_2 corrosion due to turbulent flow regime just above the ESP was the most common type of corrosion and the main reason for failure of ESP wells was due to the induced hole in the tubing string.
- The presence of CO_2 in oil wells would increase the possibility of tubing to be corroded and ESP to be failed.
- The best way to mitigate CO_2 corrosion is to run alloy steel 13% CR-L80 production strings in all Main pay wells.
- No failure of ESPs due to corrosion have been reported in the wells which have received full strings of 13% Cr tubing.
- Installing 5 joints of 13% CR-L80 tubing right above the ESP would not prevent corrosion.
- The time to replace the corroded tubing & failed ESP will cause a large loss of oil production and increase the possibility of fishing operation by rig workover.

L80: Carbon steel or alloy steel tubing string. Chemical composition:

	C	Mn	Mo	Cr	Ni	Cu	Ti	P	S	Si	V	Al
Min	–	–	–	–	–	–	–	–	–	–	–	–
Max	0.430	1.900	–	–	0.250	0.350	–	0.030	0.030	0.450	–	–

13CR-L80: 13% Chrome L80 carbon steel or alloy steel tubing string: Chemical composition:

	C	Mn	Mo	Cr	Ni	Cu	Ti	P	S	Si	V	Al
Min	0.150	0.250	–	12.000	–	–	–	–	–	–	–	–
Max	0.220	1.000	–	14.000	0.500	0.250	–	0.020	0.010	1.000	–	–

Glossary of Terms

ESP	Electrical submersible pump
CO_2	Carbon dioxide
pCO_2	The partial pressure (bar) of the CO2 multiplied by the fugacity coefficient
t	temperature in °C

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Declarations

Competing interests We would like to confirm that there are no known conflicts of interest associated with this publication.

Consent for Publication We all strictly follow the ethics of publication and we have the consent to participate.

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