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Corrosion protection and the cost of failure

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Abstract

Mitigating corrosion on offshore structures is a major contributor to the maintenance cost during the operational phase. Experience has shown that by specifying appropriate coating systems and giving sufficient priority to coating related work during the project (CAPEX) phase, will give significant savings and HSE benefits during the operational phase (OPEX). Lifetime extension of the existing offshore fleet is also becoming increasingly relevant due to technology advances allowing increased oil recovery and thus extending the lifetime of the field. A large part of the world's offshore fleet have already passed the theoretical design life of 20 years, and we are in some cases looking at extending the asset life with as much as 20 additional years. A well run maintenance program against corrosion will be critical in order to maintain the structural integrity and safe operation of the asset.

Keywords: corrosion, coating, failure, cost

Introduction

Over the years there seem to be a general trend towards fast track developments in order to speed up the return on investment. Many of the new oil discoveries are also much smaller than in the past, in more challenging areas, which in turn force many operators to look at where they can cut cost during the project phase. However at the same time we are seeing increasingly longer design life, in some cases as much as 30-35 years.

60% of the world offshore fleet has passed their theoretical design life of 20 years and more than 50% of the DNV classed mobile units is above 20 years of age. At the same time technology advances in increased oil recovery (IOR) have evolved, resulting in many oil fields are currently undergoing extensive lifetime extension programs.

Corrosion protection by the use of coatings is one of the activities that frequently are given low priority during the CAPEX phase, very often resulting in high maintenance cost during operation due to coating failures as a result of, incorrect specification choice, climatic conditions, poor surface preparation and/or poor application.

Methodology

Findings described in paper is based on papers and presentation listed in references, in addition extensive asset surveys and interviews with operators and contractors has been a major source to verify problem areas, application and maintenance issues.

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Results and discussion

Performing coating related maintenance offshore on production units are between 15-20 times more expensive per square meter, compared to performing work at a yard. This fact should by itself create a strong incentive to make sure the coating work is done properly during the project phase.

Experience show that 85% of coating failures appear within the first 1-3 years and that 95% of coating failures occur due to:

- Incorrect specification choice
- Insufficient surface preparation
- Insufficient application work
- Application during unfavorable climatic conditions

A study performed by the Norwegian oil and gas association concluded with that all FPSO's (Floating Production Storage and Offloading) in operation have suffered from inadequate paint work. The study concluded with that painting of FPSO's is a critical area to ensure a low maintenance facility. (1)

Surface Preparation during offshore maintenance

In order to achieve as long maintenance intervals as possible, good surface preparation is important, ideally one should aim for Sa 2.5 however reality do not always allow grit blasting. In fact our studies show that as much as 80% of surface preparation is done by mechanical preparation. The reason for such a high percentage of mechanical preparation is the danger of damaging rotating equipment with grit, another issue is that grit blasting requires masking and habitats and thus gas detectors and fire detectors might not work in the area where maintenance is performed and therefore pose a significant HSE risk.

Maintenance application methods

Most paint products utilized for maintenance are designed for airless spray application, however our studies revealed that only 30% is applied by airless spray and the remaining is applied 10% by brush and 60% by roller. The traditional way of solving this has been to add thinner. By thinning the products one alters the rheology of the paint making it easier to apply. By utilizing products not designed for brush and roller application one run the risk of not achieving the required dry film thickness (DFT) in addition to poor leveling, this will in turn lead to premature corrosion and more frequent maintenance cycles. One also run the risk of the applicator only counting the number of coats based on the typical DFT given in the product datasheet; however the typical DFT given in the technical datasheet is valid for airless spray application only, resulting in too low DFT's unless one frequently perform DFT measurements.

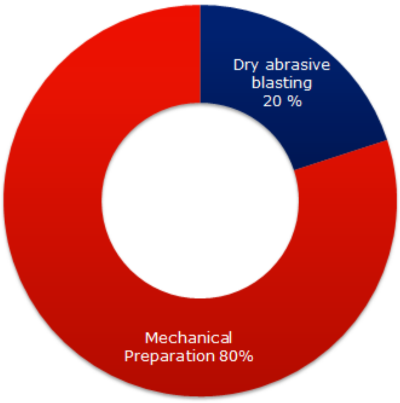

Figure.1: Surface preparartion method utelized during offshore maintenace

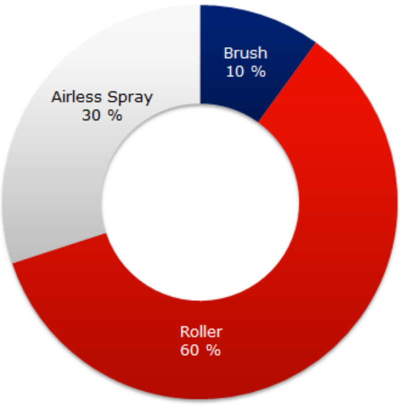

Figure.2: Application method utelized during offshore maintenace

Corrosion can account for as much as 60% of all maintenance cost (2). Thus making sure coating work is correctly specified and carried out during the CAPEX phase significantly reduces costly maintenance work offshore. Most offshore assets also experience significant maintenance backlogs due to the lack of bed capacity for the maintenance crew; this can in turn increase the risk of unscheduled shutdowns or accidents caused by corrosion. In some cases one may need to hire an accommodation rig/vessel to carry out maintenance in order to avoid too severe backlogs. The likelihood of having to rent an accommodation unit as a result of maintenance backlogs are believed to be higher on older production units. Ongoing and planned lifetime extension programs have recently resulted in an increase in demand of accommodation units. The daily rate of an accommodation unit is currently around 250.000 USD pr day.

In order to prolong the maintenance intervals with the above considerations in mind one should utilize high quality coating systems that are surface tolerant and designed for brush and roller.

Critical areas

Mobile offshore units are required by class societies such as ABS, DNV GL and Lloyds to enter a yard for inspection every 5 years, and carry out any maintenance work if needed. Production units such as FPSO's are not able to enter a yard or dry dock for inspection, therefore class inspection will be done on the field every 5 years to inspect the structural integrity of the unit, this might be more frequent if unit have passed the theoretical design life.

The stationary or fixed production units have a number of areas that are deemed critical. The three most common are commented on;

1. **Water Ballast Tanks**

Water Ballast Tanks (WBT) represents a large surface are on most floating units. The ballast tanks pose a high corrosion risk due to contaminants in seawater and various water levels in tanks, and where the cathodic protection only works when submerged. Current practice dictates the use of IMO PSPC approved coatings with a 15 year lifetime expectancy and dry docking program. One might question if these coatings are relevant for the operational conditions on an offshore unit that is expected to stay on the oil field for more than 25 years with no dry docking. Coating failures on some older units may suggest that the coatings can become brittle over time and cause coating failures.

2. **Crude oil tanks**

Common practice is to coat the upper (deckhead) and lower parts (tanktop) of the crude tanks, representing the gas and water phase in the tank, and as such pose a corrosion risk.

The upper deck plate in a crude oil tanks are often prone to corrosion. This is due to the fact that crude oil tanks are commonly inerted with CO_2 gas to avoid the danger of explosion. The CO_2 gas is often mixed with humidity as a result of temperature variations between night and day combined with condensation and lighter fractions from the crude oil, the condensate becomes an acidic concoction of hydrocarbons. Thus the use of phenolic epoxy is recommended in this area, as it offers better chemical resistance.

The lower part in the crude tanks or bottom plating is exposed to pitting corrosion caused by aggressive conditions through a mix of water, contaminants and heating coils. Some operators mitigate this effect by the use of sacrificial anodes. Crude oil with sour components and elevated temperatures will increase the risk of pitting corrosion in the bottom of the crude tank. Double hull units also run the risk of Sulfate Reducing Bacteria (SRB) as a result of elevated temperatures, caused by the so called thermos effect due to the double hull design. The use of phenolic epoxy is recommended in order to provide the best possible protection against corrosion in an acidic environment.

3. **Corrosion under Insulation**

Corrosion under insulation (CUI) has been an industry challenge for many years in the offshore industry. The corrosion processes are well understood but yet CUI often goes undetected until the damage is significant. This is due to the fact that most operators lack an inspection program for CUI, and that there are no reliable nondestructive inspection methods to detect CUI. Studies performed by the Health and Safety Executive (HSE) revealed that as much as 60% of hydrocarbon leaks (HC) are caused by ageing such as either fatigue or corrosion (3). CUI represents a major threat that might lead to catastrophic failure, in particular on HC equipment or lines operating under high pressure.

CUI on carbon steel and stainless steel occurs due to, infiltration of water under the insulation caused by; rain, process liquids, fire water, etc. The insulation material may also contribute by creating a crevice for water retention, absorption of water or leach contaminants that increase the corrosion rate.
The design of the process plans is also an important factor influencing the likelihood of CUI occurring. Typical areas to look out for where CUI is likely to occur are: Water traps, eg low points, brackets, penetrations, support rings, areas of traffic where there is a likelihood of damaging insulations covers and allow water to enter.

A good quality phenolic epoxy, designed to handle the temperatures involved, and immersion conditions, is probably the most cost efficient way of handling the CUI issue.

Case study: FPSO conversion project with design life of 13 years

A study has been done on a selected FPSO conversion project to see how the corrosion performance was after the first 3 years in operation. The hull was converted in a Chinese yard with process modules and pipework subcontracted to a number of smaller yards.

The survey revealed that there was significant damage on the unit due to coating failures, much more than could be expected. The coating specification selected should not have caused this. However when going back looking in documentation at constructing phase, it became clear the breakdown was caused by errors in surface preparation and application during the construction phase. Many of the failures was caused by cutting and hot works after initial painting was done and thus damaging the coating. Pipe spools and process modules produced at other sites looked ok but were exposed to mechanical damage during transport and installation.

Figure.3: Example showing that blasting and painting of piping at workshop was of good quality. However paint work experienced a lot of mechanical damage, during transport and installation in addition to dirt on site.

The premature breakdown of the coating systems will need to be corrected offshore at the field for a considerable expense to the operator.

Looking at a typical FPSO conversion project the numbers look like this:

- Total FPSO CAPEX cost = 800 MUSD
- Cost of paint 1% of total investment = 8 MUSD
- Cost of surface preparation 4% = 32 MUSD
- Cost of scaffolding 3% = 24 MUSD
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Total paint related cost: 64 MUSD

Conclusions

Putting sufficient recourses in choosing the correct paint systems and follow up of surface preparation and application work represent a good return on investment for the operating during the operational life of the asset.

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