Adjusters' Insight

Coating Failures and their Costly Consequences

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It is a well-known fact that bare steel will rust when exposed to water or moisture, especially saltwater. Protective coatings, in simple terms, protect steel from corrosion by acting as thin barriers to inhibit or significantly delay moisture and salt contacting the steel. This is critical in the hydrocarbon industry, where a combustible gas or liquid release can result in catastrophic damage and loss of life.

Protective coatings are basically paints usually containing a combination of extender and functional barrier pigments to achieve the desired physical and impermeability properties of the cured coating. Barrier pigments usually have a flat, plate-like shape to inhibit moisture and soluble salts reaching the steel.

Although only a very small component of the overall oil and gas project, the protective coating system can have a disproportionate effect on success and project budgets if a failure or widespread defect occurs.

In this article **Andrew Hodkinson, Regional Head and Senior Resources Adjuster, Australia & New Zealand**, has called upon the knowledge of coating expert **Dr John Scheirs of ExcelPlas** to shed some light on the history of typical failures experienced, and the latest technology and evolution of coatings in the past decade in their application to the hydrocarbon industry.

Introduction

While corrosion is a serious issue in virtually all oil, gas, pipeline, and industrial facilities, it is a particular challenge for the LNG sector, whose facilities must remain corrosion resistant despite continuous operation in areas prone to high humidity, rainfall, and tropical monsoons.

Frequent coating maintenance is disruptive to production, requiring blasting off the old coatings, meticulously cleaning the underlying surface of contaminants such as soluble salts, and then reapplying multiple coatings. Even with this costly and frequent maintenance regime, undetected corrosion can still eventuate to LNG vessels and carbon steel assets, and this can lead to leaks, fires and accidents, as well as accelerate premature replacement.

Therefore, during a large and complex LNG module construction there is considerable maintenance rework required in respect of coatings. This is a necessary task given the criticality of the coating to the safe operation of the plant.

As much as 30-60% of total blasting and painting man-hours over the course of a two- to three-year module build[1] can be devoted to addressing coating defects, poor dry film thickness (DFT) control, assembly related damage, delays due to weather, and rework of abrasive blasting or painting when the coating standard and performance specification has not been met.

Accordingly, one of the largest challenges facing the oil and gas industry is the difficulty of accurately predicting project schedules and total cost. On occasion, the successful application of coating systems can take longer to achieve than first envisaged in the FEED[2] stage of a project, which can result in schedule pressures.

Unlike a smaller industrial project – in which dry, clean, shop-primed steel surfaces can be achieved and painted in sections at indoor locations under controlled conditions – surface preparation and coating of large oil and gas projects' constituent modules such as Floating Production Storage and Offloading units (FPSOs) in sea-side module construction yards occur in largely uncontrolled environments. Less than ideal conditions with temperature fluctuations, exposure to the weather, and environmental contaminants can detrimentally impact the quality of the coated steel and the dried protective coatings.

Additionally, applying protective coatings in tropical environments is challenging, as the relative humidity is often greater than 85%. In these environments, maintaining a clean bare metal surface after abrasive blasting, without contamination from chlorides or the formation of flash rust, is virtually impossible.

[1] In the last 10 years or so, the LNG industry has adopted a pre-fabricated building module construction method where process buildings are constructed in a yard remote to the actual project site. The intent is to substantially reduce the labour and logistics costs involved so that large scale projects can be built quickly and cost effectively.

[2] Front End Engineering & Design

Performing traditional abrasive blasting – in which multiple decks of modules and thousands of workers are crowded into tight workspaces – slows processes, causes confusion and chaos, and results in coatings work that is less than optimal in terms of DFT control and degree of cure. These circumstances often lead to reworking and recoating of the defective areas.

As shown above, the initial front end fabrication effort which involves careful selection and installation of coatings is very important to the success and longevity of the coating system and whether or not it will be fit for purpose.

Why are coatings required for oil and gas facilities?

Protective coatings normally based on epoxy, epoxy-phenolic and/or silicone/polyurethane coatings are a thin veneer protecting billions of dollars of critical oil, gas and LNG infrastructure from corrosion. In particular, offshore and marine applications such as oil and gas platforms, LNG processing facilities have to resist the aggressive environment of high chloride (salt), high UV and splash zones. In tropical environments there is additional exposure to extreme UV, heat, humidity, and heavy rain cycles.

The coatings are essential in protecting the steel piping and vessels which operate at high temperature and pressure and contain volatile hydrocarbon oil and gas. (Note that coatings are one form of corrosion protection – other systems such as cathodic protection or inhibitor dosing to production fluids are also used but not considered in this article).

In the context of insurance claims, the issue of coating failure and/or defects most often arises under a Construction policy where defects from faulty installation or specification can manifest. Should coatings fail in a situation where inspection was difficult or not completed, then this can lead to pipeline / tank rupture during operation with significant environmental contamination and consequent safety issues.

Dr Scheirs has attended both onshore and offshore facilities to advise on coating selection, but also to undertake root cause investigations on behalf of Charles Taylor Adjusting (CTA).

How are the coatings selected and specified?

Protective coatings are selected on the basis of the degree of corrosion protection required for the asset to be protected and the operating temperature of that member (e.g. process piping). For example, below are some typical coating specifications for different applications along with the coating thickness expressed as dry film thickness (DFT). Prolonged structural integrity is directly related to the qualities and resilience of the protective coating system selected, the number of layers applied, and the quality of the application of the coating.

Exposed Pipework on onshore LNG Module:

Three coat system (350 μm Total thickness) as follows:
Phenolic Epoxy with Barrier Pigment e.g. glass flake or mica – 150 μm
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UV stable Acrylic Silicone topcoat – 50 μm

Offshore Module topsides:

Four coat system (275 μm Total thickness) as follows:
Zinc silicate – 75 μm
Micaceous iron oxide epoxy – 2 coats x 125 μm /coat
Polyurethane topcoat – 50 μm

Offshore Module wind/water area:

Five coat system (490 μm Total thickness) as follows:
Epoxy primer – 40 μm
Glass flake epoxy – 2 coats x 150 μm/coat
Micaceous iron oxide epoxy – 100 μm
Polyurethane topcoat – 50 μm

Hull under water:

Six coat system (865 μm total thickness) as follows:
Epoxy primer – 40 μm
Glass flake epoxy – 2 coats x 150 μm/coat
Coal tar epoxy – 75 μm
Self-polishing copolymer anti fouling system – 3 coats x 150 μm/coat

How are the coatings installed?

The application of a protective coating involves either spraying or brushing the protective coating material onto the prepared steel surface. Protective coatings are most commonly applied by airless spray application after suitable surface preparation of the underlying steel by abrasive blasting.

Extremely simplified, the application of a coating involves the removal of any surface contamination (such as mill scale, rust, oil, previous coatings/paints), followed by surface preparation to produce a blast profile (that is, a series of peaks and valleys in the surface of the steel to enable the coating to better adhere to it), and subsequently, the application of new coating (generally more than one coat). It is important to remove surface contaminants (oxides, soluble salts, hydrocarbon oil) that can induce premature coating failure.

Removal of old coatings and surface preparation of the steel is usually accomplished via water blasting, steam blasting or abrasive blasting. This process often creates a large debris cloud of both blasting media and removed product.

It is critical that the steel surface is tested for residual contamination such as mill scale (from the original steel), dust produced from blasting media and exfoliated metal surface contaminants and chlorides (either impurities in the blast media or salts from the environment).

Most large oil & gas structures such as FPSOs are constructed in module yards at coastal facilities such as those in South Korea, Thailand, and China, making sea salt contamination highly likely.

Another potential issue can arise when the air compressors used for the blasting process deposit oil droplets on the steel that can cause future coating adhesion problems such as delamination.

What is the expected life and wear of coatings?

FPSOs for LNG are being installed with expectations of remaining on location for at least 20 years. Most coating specifications for LNG and oil projects call for 15 years to first maintenance (i.e. time to first maintenance).

Traditionally, specifications require that all steel work be suitably coated with protective coatings (or paint) that are most commonly epoxies or epoxy-phenolics. Certain areas are required to be protected with an epoxy-type immersion coating including salt-water ballast tanks and cargo holds of bulk carriers.

What premature failures are possible and how do they occur? Some hints and tips for laypeople

The following table lists some of the common causes of premature coating failure and their effects:

Typical Coating Failure Causes and Consequences

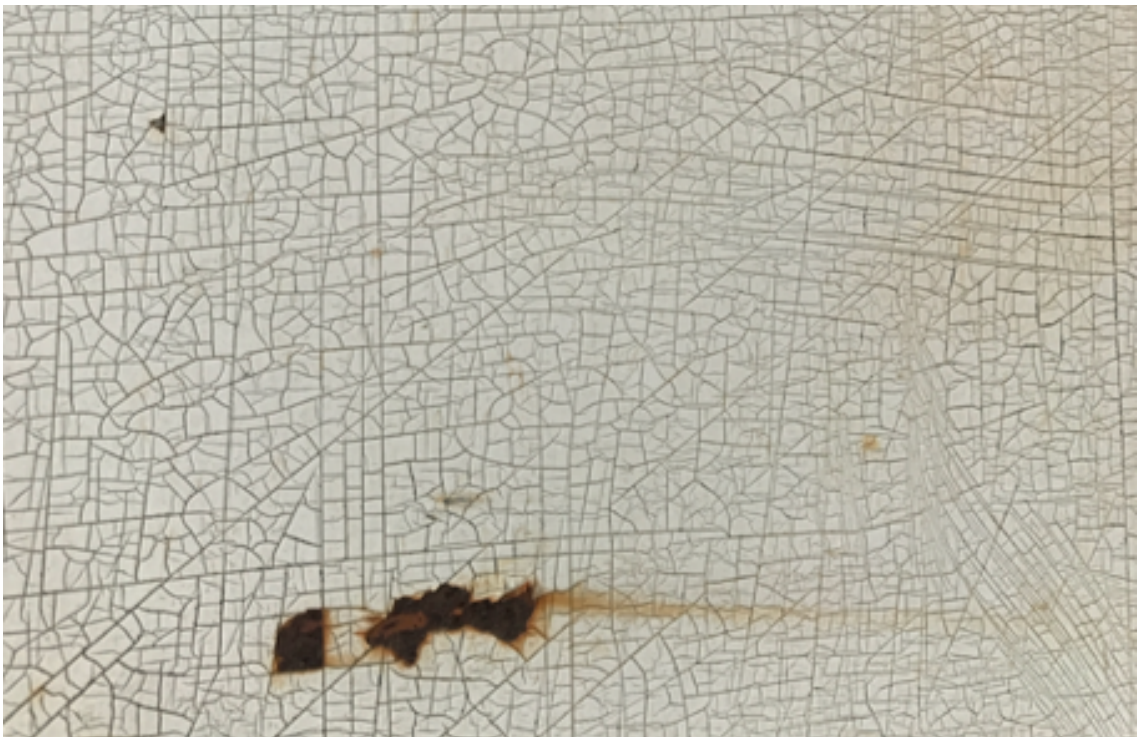
1. Inadequate blasting and insufficient removal of mill scale from the steel: poor adhesion
2. Use of blasting grit with salt contamination: osmotic blistering and under film corrosion
3. Oil contaminated compressed air used for blasting: Surface contamination leading to poor adhesion and delamination of the coating.
4. Inadequate blast profile i.e. shallow valleys: poor adhesion
5. Excessive blast profile i.e. high peaks: poor steel coverage and risk of corrosion, particularly for low DFT coatings.
6. Excessive delay between blasting and coating causing flash corrosion contamination leading to poor adhesion and corrosion cells
7. Addition of too much thinner that increases the potential for porosity and pinholes in the coating. There is also an increased propensity for the formation of Bernard Cells where there are boundaries of resin rich coating, resulting in "crows feet" cracking.
8. Poor mix ratio of the epoxy with the hardener leading to incomplete cure
9. Inadequate mixing/stirring of the coating before application leading to poor distribution of barrier pigments: coating cracks and premature corrosion
10. Inadequate coating specification: lack of suitable topcoat for UV sensitive epoxies leading to chalking and UV breakdown
11. Inadequate curing of coatings leading to less than optimal properties of the coating with increased moisture penetration and formation of corrosion cells
12. Incompatibility of coating if different paint systems are used multicoat application
13. Poor QA leading to inadequate control of coating thickness: excessive DFT can lead to cracking of the coating due to residual stresses
14. Poor QA leading to inadequate control of coating thickness: low coating thickness or missing coats can lead to poor barrier performance and premature corrosion
15. Exceeding the recoat window: leading to delamination of topcoat from primer coat due to contamination or lack of interfacial adhesion.

Construction Policy Response

In the event of a loss, all the above issues require careful consideration in the context of a Construction policy, especially if the wording contains LEG 2 or 3 Exclusions. Importantly in such claims, the search for Insured Damage is critical and almost always, corrosion is excluded. So, is there a claim afoot or not? The cost to reinstate will certainly make all parties take a very close look.

LEG 2/96 excludes any defective component part or individual item and access costs but gives cover for resultant damage to property containing the defects and other damaged parts of the insured property that are free of defect provided there is damage to the defective portion. The intention is to exclude the costs of correcting the defect, which would have been incurred, had this been carried out immediately before damage occurred. Often this exclusion will reduce a coating claim to 'zero'.

In contrast, the more generous LEG3/06 exclusion provides full cover for both defective and non-defective property provided there is damage to any portion of the property containing the defects as a result of the defect. However, the cost of improvements to the original design, plan, specification, workmanship, or materials is excluded. In some circumstances, it is possible to have a coating claim paid when LEG3 is applicable.



Mosaic Cracking and Underlying Corrosion of an Epoxy Coating on a Metal Tank (Source: ExcelPlas)

Why are coating claims often difficult to investigate?

Identifying the root cause of coating failures is often very complex because there are usually several probable mechanisms that lead to each type of coating degradation.

Therefore, extensive analytical testing is required to pinpoint the mechanism of the coating breakdown or coating defects. This not only requires forensic laboratory testing; the documented quality data on the coating application such as Paint Inspection Records (PIR) must also be scrutinised.

With large projects, investigation generally requires extensive testing of hundreds of samples and testing of the coatings under different conditions, with accelerated testing in conjunction with analysis of thousands of pages of quality data to determine the many probable causes of failure.

Typically, in any coating failure analysis where the coating is not preventing corrosion or there are signs of delamination or cracking, then the following questions need to be answered:

- Has the coating been correctly specified?
- Was the coating correctly applied?
- Does the coating meet the manufacturing standard, including properties such as correct hardness/cure, adhesion and thickness?
- Was the correct recoat window adhered to?
- What surface preparation and atmospheric conditions must be achieved to successfully apply the coating?
- Does the coating have any defects in it? How will these affect performance?
- With all of the above considered, why did the coating fail? What other environmental aspects may feed into the root cause assessment.

Once the root cause has been identified, policy response can be considered. Often there will also be issues pertaining to how the failed system might be reinstated. There can be multiple options depending on the degree of failure and the degree of access afforded.

CTA and ExcelPlas have investigated several protective coating failures around Australia, and each matter can be similar but with a different root cause. This goes for the policy response too!

Advances in the Evaluation and Assessment of Protective Coatings

Electrochemical Impedance Spectroscopy (EIS) is a powerful and sensitive tool to detect the condition of a coated metal. This technique can generate quantitative data relating to the quality of a barrier coating and the plot of data can be used to indicate the status of coating long before any visible damage occurs. EIS can also be used as a post-evaluation tool to indicate the barrier property or any change in the coating after the test exposure, such as QUV weathering exposure[3], Autoclave test, Atlas Cell test, Salt Fog or Immersion test, etc.

Other coating investigation tools include examination of the cross section for porosity, voids and cracking in the coating via optical microscopy (OM) and scanning electron microscopy (SEM). High levels of porosity can lead to internal weakness and stress cracking (these techniques can also obtain film thickness of individual layers and the total thickness at the same time).

SEM/EDX[4] analysis of the underside to look for potential contamination such as chlorides and mill scale/corrosion products. If delamination of the coating has occurred, the surface texture can also be examined by SEM and profilometry to determine if there is a blast profile.

Cure properties can be investigated by DSC to determine the glass transition temperature (Tg) and residual exotherm of cure; Infra-Red (IR) analysis can be used for positive material identification with comparison to authentic reference materials in a library database; and Nitrogen Analysis can be used to determine if the base and hardener were mixed at the correct ratio.

Measuring Dry Film Thickness (DFT) of an Epoxy Phenolic Coating (Source: ExcelPlas)

[3] Sunlight, heat, and moisture cause millions of dollars of material damage every year. The QUV accelerated weathering tester reproduces the damage caused by sunlight, rain and dew. In a few days or weeks, the QUV can generate the same degradation that occurs over months or years outdoors. The QUV tests materials by exposing them to alternating cycles of ultraviolet (UV) light and moisture at controlled, elevated temperatures. The QUV simulates the effects of sunlight with fluorescent UV lamps, and it simulates dew and rain using condensing humidity and/or water spray

[4] **Scanning Electron Microscopy (SEM)** with Energy Dispersive X-Ray **Analysis (EDX) SEM** provides detailed high resolution images of the sample by rastering a focussed electron beam across the surface and detecting secondary or backscattered high energy primary electrons.

Summary

Coatings are a fundamental barrier to corrosion and consequently required to support safe operation of hydrocarbon facilities. The consequences of failure can be sometimes unexpected and catastrophic. It is therefore important to ensure that the coatings selected are appropriate and correctly installed such that the necessary corrosion protection is achieved.

Given the criticality of coatings, when tell tail signs of failure are detected, it is imperative to investigate the root cause(s) of the coating failure to understand not only the current condition and performance of the coating, but also to ensure an appropriate reinstatement or repair method can be deployed in a cost effective and timely manner.

Often insurance will be drawn into coating failure matters, and when adjusters are appointed to investigate it is important that this work is completed to a technically competent standard.

The devil is in the detail and the root cause of a coating failure is not always obvious or easy to elucidate. For this reason, CTA will often engage the services of a consultant like ExcelPlas for the benefit of progressing the cause investigation and allowing Insurers to make an informed decision on policy response.

References

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About ExcelPlas

ExcelPlas Labs have been serving the gas, oil and water industries for the past 20 years within Australia, New Zealand and Oceania. The company is a major testing provider to the pipeline and LNG industry. Whether you're an engineer, consultant, pipeline owner, pipeline operator, LNG facility or construction company, ExcelPlas Labs can conduct a range of sophisticated analytical testing on protective coatings to assess their condition, integrity and durability. ExcelPlas Labs have extensive in-house coatings testing equipment such as DSC thermal analysis, FT-IR spectrometric analysis, TGA thermal analysis, TMA expansion/contraction analysis, EIS impedance, XRD elemental analysis, QUV accelerated weathering, high resolution optical microscope and ancillary test equipment for testing of coatings. Further details can be found at www.excelplas.com.

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