Coatings for Offshore Platforms

Experience and Recommendations

D. H. Ender

Technical Progress Report WRC 85-78

Project No. 26441

SHELL DEVELOPMENT COMPANY
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Marine Platform Coatings

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ABSTRACT

This report critically reviews protective coating practices and coating performance for steel offshore structures. The cost of Shell's offshore maintenance painting is rising through rising unit cost and a growing number of installations. For climatically new areas of offshore exploration and through possible new regulatory constraints concerning health and environment new paint material and methods may have to be adopted or developed. The need to maintain and improve the atmospheric corrosion protection of offshore structures under these changing conditions provided the main incentive for this review.

The best coating systems in use for corrosion protection of Shell platforms in the Gulf of Mexico are maintenance-free for 7 to 10 years. Localized coating problems in specific areas of the structures and uneven coating performance still exist, however. Experience with coatings for marine structures for areas much different in climate from the Gulf of Mexico, where the experience from the Gulf may not be applicable, is limited. In the future, environmental regulations relating to paint materials and surface preparation could necessitate changes in present paint practices onshore and offshore with the risk of obtaining reduced paint system performance.

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By

D. H. Ender

INTRODUCTION

As a part of our continuing involvement in coatings and non-metallics for marine environments a review has been made of experience with coatings on steel offshore platforms; emphasizing Shell's installations.

This investigation was stimulated by the increasing maintenance expense for protective coatings on existing structures and the realization that the environment associated with future offshore developments may demand changes in our present coating selection procedures.

The following report, which is the result of close collaboration between Southern Region and WRC, was undertaken to document experience as a means for assessing needs for improvement in current practice and for projecting needs for future applications under conditions not yet experienced in our offshore operations.

SUMMARY

The best available platform coating systems give 7 to 10 years corrosion protection and aesthetic appearance of steel offshore platforms in the Gulf of Mexico if the coating is correctly applied. The first paint application is onshore; this is the only opportunity for painting a platform at low cost and under controllable conditions. Offshore, painting is costly and application conditions are often not conducive for obtaining good results. The choice of the first paint for offshore projects and the quality of the first application, including surface preparation, thus affect maintenance cost much more than for projects on land.

Platform paints are chosen on the basis of our experience, with occasional minimal deviations from prior practice aimed at incremental improvements. With this approach, we expect predictable and generally somewhat improved paint performance on the Gulf Coast for which area by far the most experience is available. New paint problems must be anticipated in new developments in climates and conditions much different from that of the Gulf Coast.

New environmental legislation may affect paint performance by further restricting surface preparation methods and paint materials. With significantly different paint practices we could not be confident today of achieving current paint performance.

Different locations in Shell have arrived at somewhat different paint practices for marine structures. In part this is due to different service conditions and demands, but it also could reflect differences in assessment of paint performance and of the degree of protection required. Necessarily, in this use, paint performance must be judged from a small number of applications. The performance assessment can be confounded by cases of exceptionally poor performance. Inadequate surface preparation must always be suspected, as the cause for a paint failure. But since this can rarely be proven, paint materials often are blamed injustly for the failure.

Changes in the paint system can have dramatic effects on future maintenance cost. Therefore, radical departures from existing local practice would not be made voluntarily, unless the changed practice is backed up by years of field experience or other reliable information. Furthermore, significant cost or performance advantages would have to be shown before voluntarily adopting new paints and application procedures.

PROPOSED FUTURE WORK

Coatings with improved performance already are in demand for new offshore projects. For guiding the selection of new coatings a longer term coating evaluation is required. For such a program, the following objectives can be identified:

1. Pursue increasing the maintenence-free paint life on platforms to 15 years.

2. Improve our understanding of the factors which determine paint life on platforms.

3. Investigate alternate paint systems and surface preparation methods for offshore structures.

The following programs would give the information needed:

1. Evaluate a limited number of commercial coating systems by panel tests on a platform in the Gulf of Mexico.

2. Analyze coating failures on existing platforms by laboratory methods or in the field, as seen fit.

3. Further investigate coating experience industry-wide.

4. Evaluate a small number of coating systems under close supervision in the field by painting parts of platforms and monitor coating performance.

This project (Step 4) should be started as soon as evidence of a superior coating system has been obtained.

In proposing this approach, it is assumed, that guidance in coating selection is required before full life coating tests can be completed (7 to 10 years) and that accelerated laboratory tests currently available do not prove coating performance for the field life span already achieved today.

For anticipated new offshore ventures (four new platforms/year over a ten year period starting 1981, each with 100,000 ft^2), not counting existing structures, efforts leading to longer maintenance-free periods would be profitable. Present value after tax savings over a twenty-year period discounted at 11% are approximately $400,000 if the average paint maintenance period can be stretched by 2 years (from 8 to 10 years) and approximately $1,000,000 if 7 years can be added (from 8 to 15 years). The present value after tax cost of a research and development effort to achieve the improvement discounted at 11% is estimated at $83,000.

General Requirements, Experience and Practices

The principal requirements for platform coatings is to provide economical, long term corrosion protection of carbon steel and aesthetic appearance. Ease of application and tolerance during painting of varying conditions of temperature, humidity, salt contamination and steel surface preparation quality are desirable characteristics for a platform paint. Furthermore, the paint should be easily repaired with an equally protective coating and with a minimum of surface preparation. Environmental acceptability of paints and surface preparations are increasingly of concern.

It has long been recognized good preparation of the steel and good application is imperative for satisfactory performance of a paint system. Experience with platform coatings confirm this. Efforts to improve paint results, therefore, must be coupled with adequate and rigorously enforced specifications. A program of inspection of all stages of surface preparation and coating application, therefore, is a necessity to achieve improvements.

With some coating systems we have experienced up to 10 years maintenance-free life on platforms. Additional minor improvements in life are expected from recent modifications of the paint specifications. The systems which have performed poorly have given approximately 5 years life or less. On the average, a maintenance-free life on Shell's more than 60 existing platforms is probably 8 years. Identifiable problems include early failure on specific locations on the platform, poor repairability and poor gloss retention of the coatings used now.

Some coatings at one time thought to have potential for platforms do not satisfy today's stringent requirements of durability and maintainability and have been abandoned for this use (e.g., alkyds, epoxy esters, coal tar). The paint systems NACE have included in a standard[7] (still under review by Committee T-1G-12) and several additional systems which are being used offshore are summarized in Table 1. Although most of these systems deserve consideration for use, it is unlikely that platform operators having 8 to 10 years or more good experience with their paint will switch to paint systems radically unfamiliar to them to improve on paint performance unless dictated by new circumstances.

Table 1

PAINT SYSTEMS FOR PLATFORMS[a]

System	PRIMERS					TOPCOATS[b]						FINISH COATS	
	Solvent Inorg. Zinc	Water Inorg. Zinc	Organic Zinc Rich	Wash Primer	Organic	Epoxy	Acrylic	Vinyl	Chlorinated Rubber	Poly-urethane	Flakeglass Polyester[c]	Acrylic	Polyurethane[d]
10.1.1	✓					✓							
2		✓				✓							
3	✓					✓						✓	
4		✓				✓						✓	
5	✓							✓					
6		✓						✓					
7	✓								✓				
8		✓							✓				
9											✓		
10					✓	Any compatible top coat							
11				✓				✓					
12				✓					✓				
13	✓					✓							✓
14		✓				✓							✓
15			✓			✓							✓
16	✓							✓					✓

[a]From Ref 7 and 27 and commercial literature

[b]Intermediate coats are sometimes used between primer and topcoat for adhesion promotion. These are not listed.

[c]Also with vinyl ester.

[d]Promising as a replacement for vinyl acrylic gloss retention coat, but little experience to date (1976).

Tests for Coating Selection

At the present we select platform coatings on the basis of our own field experience. Laboratory evaluation has not predicted paint performance on offshore structures well. In the late 60's, Shell's platform paint selection was guided by laboratory tests.[8,9,10] Field experience in Offshore Division bore out, however, that the zinc rich epoxy primer systems which had shown up best in the laboratory were inferior to systems primed with inorganic zinc everywhere on the platform except in the splash zone. This experience has discouraged the use of laboratory tests for such predictions.

Laboratory tests are used by paint manufacturers for screening products, but these laboratory tests do not prove long-term field performance and they may not well simulate actual service conditions. This is also true for a new test standard being prepared by NACE Committee T-1G-12.[7]

For qualifying coatings for platforms, by long-term testing to failure, test times would be approximately 10 years. Such long lead times practically exclude field testing if carried out to failure. Accelerated tests, on the other hand, are unreliable since coatings may fail due to mechanisms absent in real life. Combination of real life environmental exposure and evaluation methods of "remaining life" or "rate of deterioration" appears to be a possibility to cut test time without imposing unnatural conditions. This approach requires a better understanding of the various failure types of platform coatings than we presently have.

A continuing field test program "Effect of Surface Preparation on Service Life of Protective Coatings" is sponsored by NACE Committee T-6H-15. After 7 years exposure at 7 sites (including the International Nickel Company, Kure Beach, 80 foot lot and a Dow plant in Freeport, Texas), these tests show post cured inorganic zinc/epoxy polyamide, which we now use on platforms, to be the best in all aspects if applied over steel sandblasted to white or near white metal. Other coatings under evaluation are vinyl, epoxy polyamide, chlorinated rubber and self cured inorganic zinc/epoxy polyamide. The study also includes eight types of surface preparation, including centrifugal wheel blasting with steel grit and with steel shot and four qualities of sandblasting.

Economic Background

Shell's 8 pile platforms have approximately 100,000 square feet of painted surface above water. A guiding value for onshore application of the presently used paint system is about \$1.25 to \$1.50/sq. ft. (1975). The same painting applied offshore in the Gulf of Mexico costs \$2.50-\$3.50/sq. ft. (1975). For the North Sea, painting costs of 2-1/2 pounds/sq. yd. onshore and 3-1/2 to 4 pounds/sq. yd. offhsore (400 micron epoxy-coal tar, 1974) have been quoted.[16] Cost ratios for painting offshore vs onshore as high as 10 have been reported, due to working conditions and climate conditions. With structures being built further offshore, costs for offshore painting may further escalate due to transportation problems and the more hostile environment.

For painting in general, the different tax treatment of capital expenditures and maintenance expenditures favors keeping the cost for initial painting onshore of new construction low and planning for early maintenance. For offshore platforms, it appears that the tax advantage obtained from the low investment/high maintenance approach is more than negated by the increased cost of painting offshore, and the possibly less satisfactory results obtained under offshore conditions.

Given the paint system, application quality is the single most important factor affecting paint economics as it controls the paint life. Onshore painting is more likely to give good application and thus better economics than offshore painting.

Contract paint maintenance cost[40] for the deep water platforms of the Offshore Division in recent years were as tabulated below:

Year	Total Cost, $	Average Unit Cost, $/ft^2
1972	292,000	2.45
1973	381,000	2.16
1974	373,000	3.49
1975	870,000	3.20
1976	1,060,000	3.70
1977	890,000	4.36

The cost for painting shallow water structures (approximately 200 mostly small structures in the Offshore Division) is not included in the table. These are commonly painted by Shell personnel. An estimate of the recent total maintenance painting cost can be derived from Offshore Division's expenditure in 1974 for paint. Glidden supplied the maintenance paint for that year for a total of $195,000. For offshore maintenance the paint materials cost is approximately 10% of the total job cost (for onshore painting, the value is approximately 20%). Thus, total paint cost in 1974 for the shallow water structures in Offshore Division was approximately $2,000,000. The paint cost for Coastal Division is not presently available. Coastal Division have approximately 35 large platforms and approximately 300 small structures.

Clean-up on new platforms and maintenance painting of work areas above the cellar deck after completion of drilling is not included in the above costs. Cost for one platform is $50,000 to $80,000. Maintenance painting cost is expected to rise further due to higher unit cost and because of the greater number of structures requiring painting.

The paint cost for new construction can be estimated from the per square foot cost for onshore painting given above (1975: $1.25 to $1.50/sq. ft.).

Increasing the maintenance-free coating life, even if only new construction is considered, offers substantial cost savings. We assume Shell will build four new platforms per year over a ten year period starting in 1981, each with 100,000 ft^2 painted surface and that improved paint technology is then available as a result of research started in 1977 at a level of 0.25 man years for six years. Further assuming that the new paint technology does not affect onshore (initial) paint cost, and conservatively assuming that offshore paint cost remains at $3.20/$ft^2$, the following can be predicted for research cost and savings resulting from this work over the next 20-year period:

		$M Before Tax	$M After Tax
1.	Cost of research[a)]		
	Present value, discounted at 11%	166	83
2.	Maintenance cost savings with maintenance period increased by 2 years (from 8 to 10 years)		
	Present value, discounted at 11%	947	473.5
	PVP_{11} (Item 2 minus Item 1)	781	390.5
3.	Maintenance cost savings with maintenance period increased by 7 years (from 8 to 15 years)		
	Present value, discounted at 11%	2103	1051.5
	PVP_{11} (Item 3 minus Item 1)	1937	968.5

a) One quarter man year ($25,000/year) from 1977 to 1982 plus $30,000 for 1977 and $30,000 for 1978 for equipment.

Regulations Affecting Painting

The risk to personnel health associated with dry sandblasting used for surface preparation has led to new regulations limiting exposure of personnel to silica dust.[24)25)31] Compliance with these regulations does not seem to present insurmountable problems. However, a NIOSH Criteria Document[30] tends to further limit permissible amounts of silica in the air. Dry sandblasting or dry blasting with other abrasives containing silica could thus be eliminated. Regulations concerning sandblasting in California go beyond current federal regulations. Which regulations apply offshore and which agency controls compliance offshore appears to be unresolved at this time. So far, we have not been restricted in the use of sandblasting offshore.

Certain solvents which are part of the paint may become unacceptable as safety standards continue to evolve. This could also affect present paint practice for offshore structures by dictating changes in paint formulations.

Corrosion and Corrosion Protection of Platforms

Paint performance varies with the location on the platform and with the geographic location. Reported experience is predominantly for the platforms in the Gulf of Mexico. Coating performance is a result of the effect of the environment (climate, ocean environment, drilling mud, detergents, solvents, etc.) on the coating material and on the substrate, carbon steel, because coatings are permeable.

Below we report general experience with coatings on stationary marine structures, mainly platforms. Shell's current practice follows in a separate section. References 4, 6, 12, 13, 14, 15, 17, 18, 19, 20, 26 and 28 contain additional relevant information.

Submerged Zone

The submerged parts of the steel platforms normally remain uncoated with the exception of several feet below the water line, where coatings and thick linings are used. Marine growth and potential for mechanical damage by boats are of main concern as regards coatings near the waterline. Steel is protected by cathodic protection; submersed coatings can be damaged by high cathodic protection voltage but this does not appear to be a problem unless high overvoltages are used. The general corrosion rate of unprotected steel in sea water from several feet below the water line down is between 3 and 6 mpy, depending on salt content and pH which varies from 7.2 to 8.3. But pitting rates as high as 100 to 120 mpy have been reported for unprotected, submerged steel.[38]

In early installations on the Louisiana coast the submerged portions of the platforms were coated with vinyl paint. The primary purpose of painting was to protect the platform until cathodic protection equipment was installed towards the end of construction work. The vinyl coatings were subject to underfilm corrosion where coating damage had taken place. Cathodic protection, once installed, also contributed to the vinyl coating deterioration since conservatively high protective voltages were used.[32]

One drilling platform (South Pass, Block 42, 1955) was coated underwater with an EPON 1001 coating because of anticipated difficulties to cathodically protect. The coating was in excellent condition when inspected after 15 months and undamaged by the marine growth which covered it to the bottom depth of 75 ft.[32] At the end of 17 years, during 4 of which cathodic protection was applied, the coating was in very good condition.

A field test designed to determine the benefit of coating the submerged part of the platform with vinyl latex paint in terms of improved cathodic protection has been carried out by Shell in 1968.[34] Polarization current requirement and long term current requirement both were about 50% lower than for an uncoated structure. Coating also provided more rapid polarization and improved current distribution.

British Petroleum have installed several platforms coated in their entirety[37] and cathodically protected.

Painting of the total submerged structure has also been considered more recently for reducing current requirements for cathodic protection. Cathodic protection alone appeared more economical, where considered. In addition, painting subsea parts delays platform fabrication and has sometimes been found unacceptable for this reason.

Splash Zone

The splash zone is regarded as the zone from the low water mark to the +8 foot elevation. In the splash zone the corrosion rate of bare steel is about 50 to 100 mpy, the highest on any part of the platform. Frequent wetting and drying causes salinity on the surface to be at times higher than in the surrounding sea water. Furthermore, the water is saturated with oxygen providing an environment highly corrosive to steel.

Marine fouling takes place in the splash zone with the possibility of damage to coatings by barnacles cutting into the softer materials or the formation of corrosion cells under marine growths. Another source of coating damage in the splash zone is from impact of boats.

At the sea level uncoated steel experiences deep pitting.[18,38] Coatings and linings are prone to mechanical damage in this zone. The methods of protection in the splash zone include fiberglass reinforced epoxy or polyester, Monel wraps, increased steel thickness with coating,[1] and rubber lining. Most of these measures become complex if protection of anything but straight tubular members is necessary. Offshore Division have used coated thick steel (doubler plates); fiberglass reinforced resins have not been satisfactory for them. Coastal Division have obtained good results with fiberglass reinforced epoxy for splash zone protection.

Coating maintenance in the splash zone is difficult and costly. Good maintenance painting is possible to the mid-tide level. Below this level, special splash zone coatings or underwater curable epoxies[21,29] can be applied by hand "smearing" or with stiff brushes. To reduce maintenance in this area, it has been suggested that braces and cross-beams be either located below or above the splash zone.[20]

Corrosion protection of pipeline risers in the splash zone deserves particular attention because of the possible consequences of pipe penetration. A fatal accident occurred in November 1975 on the Ekofisk A platform in the North Sea when a pipeline riser failed from external corrosion.[33] Coastal Division experienced a platform fire (South Pass, Block 24, Platform A) due to riser corrosion under a tape coating which had been used to repair the original coal tar enamel coating. Corrosion of steel in the splashzone is accelerated if the riser conveys hot fluids. The splash zone protection systems mentioned above are also used for risers. A thick shop applied liner (0.5 inch) of Neoprene (Splashtron) is being used with very good results. Offshore Division uses Splashtron for riser protection exclusively. Concrete over asphalt enamel has been found unacceptable for riser protection in the splash zone.[33] Reference 33 presents a review of the riser protection methods used by Shell outside U.S.A.

At the upper end of the thick protective layers on vertical surfaces one must pay attention to good drainage from the face of the layer. Stagnating water can cause rapid corrosion in such locations.

Soft coatings can fail in the fouling zone within several years due to barnacle embedment. The hard coatings used on offshore structures today, particularly, those which are chemically cured, do not become mechanically damaged by barnacles. Fouling is preventable by toxic additives to coatings. The effectiveness of antifouling agents is limited at best to about 3 years due to leaching.

Cathodic protection in this zone is only effective part of the time when immersed or when at least wet.

Elevations Above Splash Zone

This environment is typified by highly humid, salt-laden air, and in some offshore areas, large temperature variations. On the Gulf Coast during summer months steel temperatures can rise to 150°F in the sun. At the high relative humidity typical for offshore even small drops in temperature of the structure will cause water condensation. In areas protected from wind and sun, wet surfaces can exist for long times. Salt is present on platform surfaces; salt, it being hygroscopic, retains water in proximity of the surface. Rain alleviates this corrosive condition at least temporarily, but areas such as the underside of decks are not accessible to rain. While these areas are sheltered from the deteriorating influences of direct sunlight, the absence of occasional rinsing by rain makes this one of the problem areas for coatings.

During drilling, the well bay area on the platform is exposed to drilling and completion fluids. Drilling muds and cement slurries are alkaline; drilling muds have pH from 9.5 to 12. Acids are also used for well treatments. Coatings are susceptible to extremes in pH either because of attack of the coating material (usually at high pH) or because of the corrosive action on the coating substrate (at low pH). The influence of spills on the coating during drilling activities are reflected by poor appearance of the coating in the well bay area and by early failure there.

Repair

Minor coating maintenance is usually performed after completion of drilling (1 to 3 years). Industry expects 5 to 8 year intervals for normal coating maintenance,[18] but shorter and longer periods are experienced.

Conditions offshore are generally poorer than onshore for obtaining good application of paint. Paint selection for long life is therefore very desirable. But installation damage must be repaired and since recoating during life of the platform is necessary, the repairability of coatings is also an important selection criterion. Epoxy coatings further cure with time. Thus, as the epoxies become older, intercoat adhesion with maintenance coatings is less. The inorganic zinc coatings used in many paint systems as primers do not adhere well to the edges of repaired epoxy coatings. Therefore, a less corrosion resistant primer than inorganic zinc is applied for spot maintenance. Short setting time is a requirement for paints to be used offshore. Of the coatings which are used on platforms, vinyl coatings and chlorinated rubber coatings are easy to bond to even if old. Both are therefore superior in repairability to the epoxy coatings.

The timing of paint repair should primarily be determined by economic considerations. Scheduling of repairs must take into consideration expected remaining life of the platform at its current location and its future utility elsewhere. Apart from the present condition of the coating, the decision to repair requires some estimate of the deterioration rate of the coating to the next opportunity for repair. There usually is an optimum time for coating repair. Delaying maintenance of the coating beyond that optimum time could result in much more costly repairs later. On the other hand, unit paint cost offshore would be even higher, due to the high cost of mobilizing, if even small failures were repaired promptly.

New Approaches to Platform Maintenance Problems

Efforts are being made by industry to develop more economical or more acceptable surface preparation methods for steel which could also be used on platforms. Surface preparation of steel by phosphoric acid wash alone, prior to inorganic zinc priming is being developed by a ship builder.[15] Continental Oil Company is evaluating wet sand blasting with inhibited sea water as an environmentally acceptable means to prepare steel offshore for priming with solvent and water based inorganic zinc.[22] Exxon use wet sand blasting in their Grand Island area. Blasting with dry ice and with abrasive free of silica also appears to be of some interest as substitute methods for sand blasting. Wet abrasive blasting immediately followed by passivation via a phosphoric acid containing spray is also of current interest. These methods may necessitate the use of primers tolerant of wet or somewhat salt contaminated surfaces.

We suggest, in some nonstructural applications on the platform, paint problems could be eliminated by using solid reinforced plastic (FRP) instead of coated or galvanized steel. Gratings, handrails and accomodations for personnel are good examples for which FRP should have potential. It must be examined, however, if FRP satisfies nonflammability requirements and if it has the capacity to carry unusual loads which might occur in handling heavy equipment.

Practice and Experience with Coatings on Shell's Offshore Platforms

Reported Shell experience is primarily for installations in the coastal and the offshore areas of the Gulf of Mexico. Shell's experience with coatings for structures in the North Sea and the two platforms in Cook Inlet, Alaska, is given further below.

With the best systems found so far, maintenance free life of 10 years is achieved by Shell in the Gulf of Mexico. This is as good as anyone's reported experience (other operators, similar government installations). The problem areas have been the +10' elevations and the cellar deck area. With present coatings, major maintenance is also necessary due to spillage of drilling and completion fluids and crude after drilling operations are completed. The principal differences between Divisions in paint systems is in the primer. Offshore Division's specifications call for post cured inorganic zinc. Coastal Division use zinc rich epoxy as a primer. Shell's platforms in the North Sea[16,26] are also primed with zinc rich epoxy. The differences in climate, in performance evaluation criteria, and service conditions may well be the reason for these differences. In particular, it should be noted that experience with structures in the North Sea is shorter than in the Gulf and in most cases shorter than the 7 to 10 years which we would consider a good maintenance free paint life under offshore conditions.

<u>Gulf of Mexico</u>[2,3]

The Offshore Division's coating specifications for atmospheric corrosion protection of offshore platforms have evolved in the course of the last 17 years. The coating systems used on the approximately 60 (1974) existing offshore platforms reflect this evolution in that we have platforms with many different paint systems (Table 2). The paint systems currently used for exterior surfaces of structures in the Coastal Division[39] and in the Offshore Division[23] are listed in Table 2.

For 60 to 80% of Shell Offshore Division's new platform construction, onshore surface preparation of structural steel is by centrifugal blasting with steel grit. For large diameter legs (54 inch) and joint areas dry sand blasting is used. For production packages and offshore maintenance Offshore Division also use dry sand blasting. For offshore maintenance, Coastal Division are blasting with coal slag since 1970 in East Bay.

The specifications presently in force[11] in the Offshore Division call for coating exterior surfaces from the minus 6 foot elevation to the top of the structure, including well conduits, flowlines, deck drain sump tanks, with post-cured inorganic zinc, top coated with epoxy. The latest revisions of the specifications have added an epoxy tie coat between inorganic-zinc and epoxy to improve bonding of the top coat; also, to correct the chalking tendency of the high-build epoxy, top coating with a vinyl acrylic gloss retention coating is now specified. These two features have worked well for other operators in the Gulf. Shell's experience with platform paint systems is restricted to epoxies and zinc containing primers although of different type and origin. The paint systems which have been specified since the first platform was put into service are summarized in Table 2 together with comments relative to their performance. The paint systems used by Shell in the North Sea since 1972 are included. The best systems have achieved up to 10 years maintenance free service; the least satisfactory systems have required maintenance after 3-1/2 years. The problem areas for paint life are the +10' elevation and the cellar deck (+45' elevation).

Table 2

OFFSHORE PLATFORM PAINT SYSTEMS[a)]

Period	Paint Systems	Qualified Products System #[c)]	Experience
SHELL OIL COMPANY - SOUTHERN REGION - OFFSHORE DIVISION			
1958-1960	Four coat amine cured epoxy (2 inhibited primer coats, 1 build coat, 1 seal coat).		Spot maintenance required after 5 years, complete recoat after 10 years, without repair breakdown after 14 years.
1964	Post-cured inorganic zinc primer, one or two coats high built epoxy.		No repair required after 10 years. The primer offers good protection by itself. Single top coat performs well.
1964-1966	Self-cured inorganic zinc, epoxy. (a) Water base inorganic zinc.		On most platforms, no maintenance required after 5 years. On two platforms extensive failure above +10', good in splash zone. Primer used on two structures was withdrawn.
	(b) Solvent (ethyl silicate) base inorganic zinc.		Slightly inferior to post-cured inorganic zinc. Above +10' some maintenance after 7 years. Delamination of epoxy top coat is a problem after 6 to 7 years.
1966-1972 First applied in 1962.	Zinc-rich epoxy primer with epoxy top coat.		Performs well in splash zone. Complete failure above splash zone in 9-1/2 years. Poor performance common to all commercial products used. Disbonds at the steel. Failures after as short as 3-1/2 years.
1972-1974	Post-cured inorganic zinc (3 mils), Inhibited polyamide cured epoxy (2 mils), Polyamide cured epoxy (6 mils),	1, 2	
1974	Post-cured inorganic zinc (3 mils), Inhibited polyamide cured epoxy (2-3 mils), Polyamide cured high-built epoxy (6 mils), Vinyl acrylic (2 mils)	3, 4	
SHELL OIL COMPANY - SOUTHERN REGION - COASTAL DIVISION			
1974	Zinc rich epoxy (3 mils) Amine or polyamide cured high-build epoxy (7 mils) Amine or polyamide cured high-build epoxy (7 mils)	5, 6, 7, 8	

Table 2 (continued)

OFFSHORE PLATFORM PAINT SYSTEMS[a)]

Period	Paint Systems	Qualified Products System #[c)]	Experience
SHELL U.K. EXPLORATION AND PRODUCTION			
1972 Splash Zone (-10' to +25')	One coat of zinc rich epoxy primer or red oxide pigmented epoxy primer (25-30 microns) Three coats of coal tar/epoxy (50/50) (135-150 microns)		Surface preparation SSPC-SP10-63T (near white metal)
Above Splash Zone (>25')	High build polyamide cured epoxy (250 microns). Above the lower deck a chlorinated rubber coat was applied.		
1977 Splash Zone	Zinc rich or red oxide epoxy primer (25-30 microns if zinc, 35-50 microns if red oxide) Three coats of coal tar/epoxy (135-150 microns each)		
Above Splash Zone	Zinc rich or red oxide epoxy primer (25-30 microns if zinc, 35-50 microns if red oxide) Two coats of high-solids epoxy (100-125 microns each) One coat of chlorinated rubber or non-slip epoxy (for deck surfaces) (25-30 respectively 35-50 microns)		

a) From references 3, 11, and 16 and verbal communication with Mr. J. A. Burgbacher, Shell Oil Company, New Orleans.

b) Coatings used by Shell prior to 1958 included a modified vinyl mastic, EPON mastic and EPON esters. Other operators used coal tar-epoxy, asphalt, fish oil, chlorinated rubber and vinyl.

c) Qualified paint systems:

#1: Ameron D-3, Ameron 1982, Ameron 383

#2: Napko 3-Z, Napko 5616, Napko 5804

#3: Ameron D-3, Ameron 1982, Ameron 383, Ameron 234

#4: Napko 3-Z, Napko 5616, Napko 5802, Napko 5510

#5: Napko 5615, Thixopoxy 5673, Thixopoxy 5675

#6: Ameron 68, Ameron 84, Ameron 84

#7: Reliance Met-L-Pon 93, Reliance Chemcure EA-1 157/159, Reliance Chemcure EA-1157/170

#8: Glidzinc 101, Glidden DGL-2168/1961, Glidden DGL-1763/1961

Primer

Performance of primers has varied between locations on the platform and between commercial products. For onshore fabrication, only zinc containing primers have been applied by the Offshore Division.

Zinc rich epoxy primers topped with epoxy have performed comparable to inorganic zinc primed systems in the splash zone. Above the splash zone, zinc rich epoxy tends to "disappear" under the top coat, causing the latter to fail by disbonding. This is often accompanied by a typical discoloration of the top coat. At the cellar deck elevation incipient failure is first noticed as pinpoint rusting and at the +8' to +15' level as tuberous blisters.

The zinc rich epoxy primer appears to be easily damaged by spillage from production and completion fluids. For example, bare metal has been exposed after 3 to 4 years on the structure under the mud tanks. Failure was especially extensive in fields requiring sand control measure, which involved the use of toluene and isopropyl alcohol.

Inorganic zinc primers provide good protection in the splash zone and up on the structure on offshore platforms in the Gulf of Mexico. Even without a top coat, for example, when the top coat has peeled off, inorganic zinc has performed remarkably well. These coatings have been used without a top coat for the main deck beams in some cases. After 11 years there is about 30% failure. At the lower elevations we do not expect uncoated zinc primers to perform well.

Inorganic zinc primers are difficult to bond to at times, requiring special attention to the timing of top coating. Attention also has to be paid to prevent contamination of zinc primer surfaces with iron particles, such as filings or weld splatter. Iron contamination leads to rapid localized failure of the primer.[35]

In Offshore Division's experience, post-cured inorganic zinc has performed best. Post-curing is accomplished by washing the primer with a chemical solution. This additional step and an inherent sensitivity to application conditions were undesirable from the contractor's point of view. With more platform operators specifying post-cured inorganic zinc primers, the initial reluctance of contractors to use this difficult primer is being overcome. One of the two water base self-cured inorganic zinc coatings used has performed poorly with paint failure after 6 years. This primer has been withdrawn from the market.

Solvent type inorganic zinc (ethyl silicate) ranks in the Offshore Division's experience slightly lower than the post-cured inorganic zinc. In the splash zone and on deck beams, two difficult areas, solvent type inorganic zinc held up well, but the +10' elevation required painting after 7 years. The epoxy top coat has, on occasion, tended to delaminate from ethyl silicate based primer after 7 years. Excessive top coat thickness may be a contributing factor to this delamination. Zinc rich epoxies are easily applied and they are less depending on perfect surface preparation than are inorganic zinc primers. Intercoat adhesion between top coat and zinc rich epoxy primer is better than with inorganic zinc primers. But in spite of these advantages, the former are no longer used on platforms by Shell's Offshore Division because of the previously mentioned problems. There does not appear to be a good explanation for the performance differences between inorganic zinc and zinc rich epoxy. Furthermore, Coastal Division is satisfied with the performance of their zinc rich epoxy primer.

Post-cured inorganic zinc primers, which are now specified, are less tolerant of poor surface preparation than the other zinc rich coatings.[5] Failure of this primer due to surface preparation tends to show up very soon after application; therefore, repairs can be made while still in the fabrication yard. With other primers, failure due to application deficiency is more likely to appear when the platform is in place. Repair will then have to be made under the adverse conditions in the ocean.

Top Coat

Epoxy has been used almost exclusively by Shell for top coating. To achieve the desired coating thickness with one or two applications, high build epoxies are being used. The thixotropic agents used to impart high build properties result in a dull, hard-to-clean surface. Epoxy coatings also tend to chalk at a rate of somewhat less than 1 mil per year. Therefore, as of late, an additional vinyl acrylic coating has been applied to the epoxy for gloss retention and improved cleanability.

Top coat cracking where coating thickness was excessive has been experienced, resulting in disbonding, especially at corners and other difficult areas. Coatings formulated to result in sagging if applied too thick (maximum build property) are now being used to avoid this problem. Porosity in the self cured inorganic zinc primers, particularly the ethyl silicates, can cause blistering of the top coats by entrapped solvents or air. The problem is more acute in the summer when surface temperatures approach 150°F.[5,36] This is partially overcome by special formulations of the top coat or by applying a tie coat over the primer.

Surface Preparation

Surface quality at the time of paint application is recognized as an aspect most vital to the paint performance. Offshore Division's specifications[11] call for a 1.0 to 1.5 mil anchor pattern and surface quality NACE No. 1 (white metal) as represented by NACE Standard TM-01-70. Sand, slag or grit blasting can be used. Centrifugal wheel blasting is admissible if grit is used.

The experience with coatings on offshore platforms reflects surface preparation methods and quality. But the quality of the substrate (anchoring pattern, cleanliness, rounded corners) for a paint is of a very elusive nature. When judging performance of a paint system, the possibility of poor surface preparation having modified its performance must not be neglected. Therefore, inspection during each application step should be an integral part of a paint job.

Surface preparation requires ease of access to every surface which requires painting. Platform design must avoid poorly accessible areas.

Repair of Coatings

Inorganic zinc coatings do not adhere well to the "feathered" edges of epoxy, a halo of rust forms around the periphery of the repaired area. Therefore, for the past 2 years, in the Gulf, coating repair is made with multiple coats of medium build, polyamide cured epoxy coating.

Coating Practice on Shell's Cook Inlet Platforms

Structural parts of the platforms were originally painted with a zinc rich epoxy primer and top coated with an amine cured epoxy. Surfaces were prepared by blasting to white metal for the first paint application. The platform legs are not painted in the 25 to 30 foot tidal range. Coatings would be rapidly worn off by the silt and ice laden water flowing at 6 to 7 knots. The zinc rich primer holds up well. The paint system gives 6 to 8 years service life in areas where there is no significant mechanical wear. Decks require frequent repainting due to mechanical damage.

For paint repair surfaces are prepared by power chipping and wire brushing. Sandblasting is not acceptable in Cook Inlet because the platforms are completely enclosed. Sand would get into air intakes of engines and machinery and cause mechanical problems. Wet sand blasting has not been tried. Mechanically cleaned steel is repainted with Copon modified alkyd barrier primer and amine cured epoxy top coat.

North Sea[1,6,14]

Early in the North Sea development poor application and inspection and insufficient specification resulted in poor performance of coatings. A multiplicity of paints were used, resulting in compatibility problems when repainting. Complete blast-cleaning and recoating sometimes became necessary after only four years of service. In 1972, with platforms in more hostile environments in the northern North Sea being planned by Shell, paint specifications were revised, a limited number of paint suppliers were approved and inspection covering all application stages was instituted.

Polyamide cured epoxy containing zinc or red oxide is used for priming. It is felt that this primer is less dependent on perfect surface preparation than the inorganic zinc used on Shell platforms in the Gulf of Mexico and it is easier overcoated.

In the splash zone a coal tar epoxy top coat is used. Above the splash zone the primer is top coated with a polyamide cured epoxy. Above the lower deck level an additional coat of chlorinated rubber is applied for color and to facilitate maintenance painting with high build chlorinated rubber. This eliminates blast cleaning for maintenance painting or coating over old epoxy, which is difficult to bond to. As a maintenance primer under the chlorinated rubber, a urethane oil type medium is used. It develops solvent resistance rapidly enough for overcoating and does not lift some of the older paints used early in the North Sea development. Periods with favorable weather for paint application offshore are brief in the North Sea. The need to paint under marginal conditions is likely to result in different requirements for paints than in the Gulf of Mexico, for example. Reference 26 presents a summary from the coating applicator's point of view of the North Sea paint requirements.

INFORMATION SOURCES

This review utilizes sources in the open literature and Shell experience. Mr. J. A. Burgbacher and several other individuals of Southern Region have supplied most of the Offshore Division's experience for this report. A wealth of experience with platform coatings exists among platform operators, but only little is well documented for our purposes.

Government agencies which have reported work on marine coatings are the U.S. Naval Civil Engineering Laboratory, U.S. Coast Guard (USCG), U.S. Naval Research Laboratory, Naval Shipyard (Mare Island Paint Laboratory) and U.S. Corps of Engineers. Battelle Memorial Institute, Columbus, have investigated for USCG coatings for protection of navigational buoys; International Nickel maintains a marine atmosphere corrosion test site at Kure Beach, N.C. and a sea water test site at Wrightsville Beach, N.C. where coatings have been tested. Some information from these sources is included in this report.

Committee T-1-1 of NACE has prepared standard[27] RP-01-76 "Control of Corrosion on Steel Fixed Offshore Platforms and Structures Associated with Petroleum Production". While not as specific on the details as our own specifications, this proposed standard is a good reference for industrial practice.

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