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New developments in coatings for extended lifetime for offshore wind structures

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ABSTRACT

After more than 15 years' service life of the first large offshore wind farms in the North Sea, mostly positive experiences are reported on the condition of the protective coating systems. Today however, the requirements for corrosion protection for new projects are often extended to at least 25 years' maintenance-free service lifetime. In comparison, the highest durability class described in ISO 12944 is more than 15 years until first expected maintenance. Therefore, much needed committee work is in progress with the intent to update ISO 12944 with extended durability classes. In order to bring down the construction cost of the support structures for offshore wind, initiatives have been taken to industrialize the coating application process and to use standard components wherever possible. Extended pre-qualification tests have recently been proposed in order to convince owners and certifiers that new coating systems may actually have 25 years' maintenance-free service lifetime. The paper discusses the need for more documentation on coating systems for extended lifetime and the possibilities of reducing the costs for corrosion protection. Valuable information from decommissioning of old wind farm structures and platforms may provide crucial information and documentation.

Key words: Offshore Wind, Marine Corrosion, Protective Coatings, Decommissioning.

INTRODUCTION

Constructions such as offshore windfarms are subject to aggressive environments. They are exposed to humidity with high salinity and to intensive UV-radiation. The UV-radiation occurs directly on the constructions as well as from light reflections from the sea. An area of special concern is the tidal zone (splash-zone), where the wind turbine construction is stressed both from mechanical impacts – service boat collisions and waves – and from corrosion strains created by shifting saline seawater with high oxygen level. The stress from seawater may be extensive in waters with high tidal activity, such as the Irish Sea or the English Channel. Thus, in particular, the protection of the wind turbine foundation, the transition piece (TP), is imperative. Long-term resistant coating systems with no need for future refurbishment – combined with flawless application operation activities – are essential, as offshore repair is costly. Following an uncertain start, the present offshore coating systems for windfarms have shown fine durability against the aggressive marine environment. Positive features from the first windfarms with more than 15 years of service are described. The importance of quality management, satisfactory coating performance testing and learnings from existing and decommissioned structures are explained in this paper.

NORTH SEA WINDFARMS – THE BEGINNING

The first windfarm in the North Sea, Horns Rev 1 was planned in the mid 1990's and implemented from 2001 to 2002. Figure 1 shows a sketch of a typical offshore wind turbine foundation based on monopile principles.

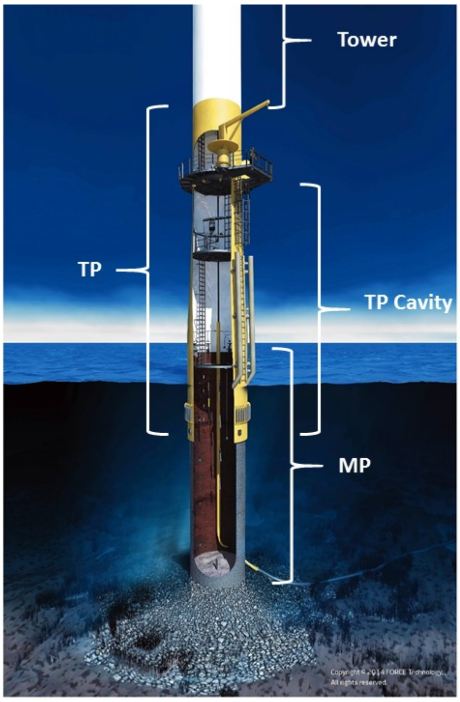

Figure 1: Offshore wind turbine construction, model: Tower, TP (Transition Piece), TP Cavity (The inner void of the TP), and MP (Monopile: The underwater support of the TP and Tower).

At that time, designers obviously considered using offshore coating systems from the oil- and gas industry to prevent corrosion. In particular, the Norwegian standard on coatings, NORSOK M-501[1] (the revisions at that time), was studied. However, and against all former studies and NORSOK M-501-systems, the previous owner of this wind farm selected a two-coat, ceramic reinforced epoxy system, applied wet-in-wet with a total dry film thickness (DFT) of 350 µm for the TP and the upper part of the MP (-2.0 m Mean Water Level, MWL and upwards). The paint system had been approved following the testing regime of NORSOK M-501, in this case applied as a two-coat system with drying between the coats. However, such a thin system was seldom used for splash-zone areas. As a test, the last 5 of the 80 TPs at Horn Rev 1 were painted with a two-coat solvent free epoxy system, total DFT 1000 µm, and with drying between the coats. The turbine tower itself was protected with a well-known epoxy/polyurethane system, primed with thermally sprayed zinc/aluminium 85/15 coating. This system had a long and successful onshore track record – also in coastal areas. Within the first two years of service, pinpoint rusting (Rust Grade 9-P, SSPC-VIS 2) was observed on the TP's painted with the thin 350 µm two-coat epoxy system, see Figure 2.

Figure 2: The thin 350 µm coating system after 2 years of service (2004). Pinpoint rusting (Rust Grade 9-P, SSPC-VIS 2) has started.

The corrosion took place both in the atmospheric and splash-zone areas of the TP. A forensic investigation showed that the corrosion started as blistering on the coated surface, and as the blisters ruptured from wave- and tide movements, the rust attacks were activated. The cause of coating failures turned out to be the thin coating combined with insufficient dispersion (grinding) of the ceramic extenders in the paint. Microscopic analyses of coating flakes showed that the extenders had not been ground and dispersed sufficiently during the production of the paint. The low DFT of the coating and the oversized agglomerates in the thin film permitted pinhole access of salt water to the steel surface. Figure 3 shows a photo from 2014 (12 years of exposure) of one of the foundations applied with this coating system. Extensive rusting is appearing on the majority of the areas exposed to the splash zone. In 2016 (14 years of exposure) the same foundations were inspected again showing almost complete loss of coating exposing the rusting steel to the environment, see Figure 4. It should be noted that the boat landings were replaced after 5 years' service, applying the 2-coat solvent free epoxy system in 1000 µm. This explains why the coating system on the boat landings appears intact with only few minor mechanical damages.

Figure 3: The thin 350 µm coating system after 12 years of service (2014). Extensive corrosion and coating breakdown is observed.

Figure 4: The thin 350 µm coating system after 14 years of service (2016). Extensive corrosion and almost complete loss of coating is observed.

The two-coat solvent free epoxy system with 1000 µm on the last five of the Horns Rev 1 TPs has shown good and lasting resistance, apart from minor damages made by impacts from supply boats. For comparison Figure 5 shows a photo from 2016 (14 years of exposure) of one of the foundations painted with the 1000 µm 2-coat epoxy coating system. The coating system appears more or less intact with no visible corrosion. Consequently, this coating system became a starting point for suitable coating systems meant for future windfarm projects.

Figure 5: The 1000 µm, 2-coat solvent free epoxy coating system after 14 years of service (2016). Completely intact coating system and no visible corrosion is observed on the TP.

Even though the thin 350 µm paint system did pass the tough testing regime of ISO 20340[2]/NORSOK M-501 it did not pass the real life service. The learnings from this case, are that pre-qualification tests alone do not necessary pull out the right coating systems for real service.

NORTH SEA WINDFARMS – THE LEARNINGS

Following the experiences from Horns Rev 1, new coating systems were introduced. The revised paint system for the complete exterior of the TPs and the jackets down to -1.0 m Lower Astronomical Tide (LAT) is shown in Table 1:

Table 1
Revised coating system for jackets and TPs (from around 2006).

Paint system for jackets and TPs	
Type	**Nominal Dry Film Thickness, NDFT (µm)**
High-build epoxy primer	250
High-build epoxy intermediate coating	250
High-build epoxy intermediate coating	250
Polyurethane (PU) top coat	80
Total dry film thickness	830

The coating system has shown excellent durability on various projects around in Europe. The few damages observed have originated from poor application quality, insufficient quality control during the painting process and impacts from installation activities and collisions. The protective ability of the paint system in marine environments is confirmed. Stripe-coating on welds and edges between every coat of paint has always been specified. This has also contributed to the positive results.

As with all industrial enterprises, all parties involved in wind farm projects are constantly searching for ways to reduce construction costs. Among these, also the cost of paint and painting. Based on the positive experience with the epoxy/PU-system and due to new developments of these types of paints, within the last five years, the paint manufacturers have recommended that the system listed in Table 1 be modified from a four- to a three-coat system. The paint manufacturers' recommendation is justified from pre-qualifications in the NORSOK M-501 and ISO 20340's testing regimes and also from good references from the offshore oil- and gas industries. Thus the paint system used in some of the latest projects is the three-coat system (System 7A, minimum 600 µm in two coats) listed in Table 2:

Table 2
Coating system for jackets and TPs (Based on NORSOK M-501 rev. 5).

Revised paint system for jackets and TPs	
Type	**Nominal Dry Film Thickness, NDFT (µm)**
High-build epoxy primer	300
High-build epoxy intermediate coating	300
Polyurethane (PU) top coat	60
Total dry film thickness	660

To apply three coats instead of four and to reduce the paint consumption will naturally create a cost reduction. Meanwhile, some operators still favor the four-coat system in about 800 to 900 µm or e.g. glass flake polyester systems in a DFT ≥ 1000 µm to obtain a higher safety margin.

Throughout the first wind farm projects, the outside of the uncoated, submerged MPs was protected by anodes. But to reduce anode consumption and to avoid costly cathodic protection retrofit solutions due to under-protection of the structures (e.g. installation of remote anode sleds), owners and contractors soon agreed to partly coat the outside of the MPs. The specified coating system for the outer (and inner) MPs is a traditional 2-coat epoxy system, such as recommended in NORSOK M-501 (System 7B, minimum 350 µm in two coats). The epoxy coating must be resistant to cathodic disbondment. Such coating systems have been used for more than 20 years in the offshore oil and gas industry with documented good performance.[3]

COATINGS FOR OFFSHORE WIND TURBINES – TRENDS AND NEW STANDARDS

The new recommended practice for corrosion protection of offshore wind turbines, DNVGL-RP-0416, "Corrosion protection for wind turbines"[4] issued 2016, is more specific on coating systems than previous versions of DNV-OS-J101[5], "Design of offshore wind turbine structures", more specifically, details regarding surface preparation have been included. According to DNVGL-RP-0416, the use of coating is mandatory for external surfaces of primary structures in the splash zone. Coating systems to be applied in the splash zone shall be based on manufacturer specific materials that have been qualified for the actual coating system by proven experience or relevant testing. Since maintenance of coating systems in the splash zone is not practical, coating of primary structures shall be combined with a corrosion allowance. However, for the area of the splash zone located below the Mean Water Level (MWL) no corrosion allowance is required. In this area the corrosion control is served by the coating system and the area is included in the CP-design (partial protection) to provide conservative dimensioning of the CP system. Coatings for corrosion control in the splash zone shall as a minimum extend to -1.0 m MWL, however it is considered best practice to apply coating to the entire vertical extension of the splash zone. All coating systems shall be pre-qualified in accordance with a recognized standard (i.e. NORSOK M-501, ISO 12944[6], ISO 20340) with the designated use and environment.

Currently ISO 12944[6] is under revision. The latest draft-version distributed for review and comments defines a new atmospheric corrosivity category, CX, for offshore areas with high salinity, which is more aggressive than the previous C5-M category. Further, the standard now also defines corrosivity category Im4 for immersed structures with CP. The durability ranges are revised and now includes a very high (VH) durability range, in which more than 25 years until first maintenance may be expected. Lastly, a new part 9 of the standard solely deals with paint systems and test methods for offshore structures and is intended to replace ISO 20340. Therefore, new more clearly defined paint systems and test requirements for long-term offshore service may be expected in 2017.

In Germany, a new standard produced by a project group headed by "Bundesanstalt für Wasserbau" (BAW)[7] has taken into consideration also the coming ISO 12944 requirements and states comparable paint systems and test requirements for paint systems for offshore wind structures (external and internal). The aim of the standard is to make sure that corrosion protection systems will protect against corrosion damages for at least 25 years. Laboratory and field test requirements are stated and required after January 1, 2018. The standard defines extended test requirements compared to ISO 12944/ISO 20340, e.g. long-term field exposure (5 years), abrasion, impact and color retention tests are required. Likewise, requirements for control during manufacturing are given and in some cases they are stricter than typically used recommendations and guidelines. E.g. 100 % high voltage pore test according to DIN 55670[8] is described for the immersed and splash zones.

In addition, in some cases, the acceptance criteria are made stricter (e.g. the rust creep of ≤ 4mm for non-zinc primed systems after ageing test according to ISO 20340).

ZINC OR NON-ZINC PRIMERS?

The strict requirement for rust creep[7] might in reality entail that primarily paint systems based on zinc-rich primers may be applicable for the splash zone. This postulate is based on the fact that non-zinc-primed epoxy coating systems in general show larger rust creep than zinc-primed coating systems in the ISO 20340 ageing test. ISO 20340 also compensates for that circumstance by having different passing criteria for zinc primed and for non-zinc primed systems of 3 mm and 8 mm, respectively. The use of zinc-rich primers for immersed service has been under debate in the ISO 12944 committee and at corrosion seminars, and to our knowledge, zinc-rich primers have not yet been applied in an industrial scale on offshore wind farms in the splash- and immersed zones, which is the reason why long-term references are not available at this point. The use of top coated zinc-rich primers for immersion service may result in blistering of the topcoat, which is the primary mode of failure when top coated zinc-rich primers are placed in water immersion service.[9] If water permeate the topcoat, zinc salts will form at the primer/topcoat interface and with time result in blistering due to osmosis and volumetric expansion. One may even imagine that the zinc rich primer may act as a sacrificial anode at coating damages in areas with poor polarization by the cathodic protection system, causing rapid spread of adhesion loss. However, most importantly the galvanic protection from the zinc primer is not needed, since this is provided by the cathodic protection system.

Not much literature is available on the performance of zinc-rich coatings under cathodic protection. The influence of cathodic polarization on the degradation of an epoxy coating (120 µm) and an 80 wt.% zinc-rich epoxy coating (60 µm) has been investigated in a laboratory study.[10] No topcoats were applied. For the zinc-rich epoxy coating it was concluded that cathodic polarization at −0.9 V (SCE) in 3.5 wt.% NaCl solution for 47 days decreased the dissolution rate of the zinc particles in the coating and increased the coating durability. The activation of zinc particles was delayed and the cathodic protection time by the zinc particles was prolonged. This study indicates that the performance of zinc-rich epoxy coating is improved by cathodic polarization.

DNVGL-RP-B401, mentions that galvanizing used in conjunction with CP will not provide any benefits as the zinc layer provide a limited anode capability. Consequently (according to DNVGL-RP-B401), there is no practical benefit in using galvanizing on submerged items. Likewise, and based on the study by Yu Zou et al.[10] it can be argued that the application of zinc rich primers on immersed structures under CP is unnecessary and does not provide any significant advantages. However, in the splash zone around the MWL, the CP system will not be fully functional and zinc rich primers may provide some cathodic protection and limit rust creep. On the other hand, the risk of topcoat blistering and adhesion loss due to corrosion of the zinc primer in this area has to be considered and counterbalanced, when selecting the most optimal coating system. In general, zinc rich primers are mechanically weaker compared to the topcoats used in offshore service (epoxies), which may make the coating system more prone to cracking, especially in case of mechanical impact (e.g. on boat landings). This risk should also be considered when selecting coating system and specifying quality control requirements.

COATING SYSTEMS WITH LONG SERVICE LIFE

Today there is still debate regarding the most optimal coating systems for offshore wind structures. Pre-qualification of the systems far from guarantees successful corrosion protection, since many other factors are decisive for the durability of the systems. Most defects, but not all, actually occur due to faulty processing or erroneous application and not incorrect specifications. Damage analyses in Germany[11] have shown that faulty processing and/or erroneous application have caused between 43 % and 68 % of premature coating failures. Coating failure cases in the offshore wind industry have also been reported by Black[12]. Furthermore, Momber[13], has performed a review of inspection results on offshore wind power structures in the North Sea and the Baltic Sea and described several damage types observed, including under rusting, flaking, mechanical damage, wear, transportation damages, galvanic corrosion and more, damages that are mainly related to poor design, handling and work on-site.

Basic rules for anticorrosion construction design is explained in ISO 12994-3 and includes e.g. good accessibility of the parts and sections to be protected, avoidance of gaps, joints and overlapping connections, precautions against deposits and accumulation of water and dirt, rounding of edges, treatment of weld seams and surface imperfections, prevention of galvanic corrosion and careful handling, transport and assembling of the parts to be protected. In order to secure optimal coating quality, it is crucial that all application work is carried out in accordance with the international as well as the owner's specific standards, following the guidelines described in the paint's technical data sheet. This may be ensured by qualified supervision of e.g. FROSIO or NACE-qualified coating inspectors as recommended in DNV-RP-0416, NORSOK M-501 and NACE SP0108.[14]

LEARNINGS FROM DECOMMISIONED CONSTRUCTIONS

Field failure analysis is known from the electronics industry[15], where field failure parts returned by random sampling from the agreed reference market are analyzed and tested in order to understand the failure cause. This may help reduce testing cost and direct analyzing resources towards field failures with new or unknown failure causes, which do not appear in accelerated testing.

A similar approach may be relevant for offshore wind components including the support structures. When the wind farms are decommissioned, forensic analysis of the condition of the structures including the protective coating systems may provide valuable information for future projects, accelerated testing regimes as well as standards and guidelines, which to a high degree are based on experiences from the field. The costs for such analysis may be rather limited compared to the benefits, but such work is seldom included in the decommissioning program.

The information derived from analysis of the decommissioned structures may include information such as the condition of the coating according to ISO 4628[16], and the anode consumption. The results may be compared to the design basis and project specifications and preconditions.

Example 1
An inspection of a number of monopiles from decommissioned wind turbines placed at Yttre Stengrund in the Baltic sea was performed after 15 years of service. The foundations extended to 10 m above MWL. At +10 m there was a 4 m diameter flanged connection to the main turbine tower.

The area in the Baltic Sea is affected by sea-ice, so an ice protection shield (ice cone) had been provided between high and low water levels. The piles were protected from corrosion by a protection system comprising of an epoxy based coating with ceramic pigmentation in addition to cathodic protection below the water level and a corrosion allowance in the splash zone. The foundation was designed to provide an operating life of at least 20 years and to withstand the environmental loading from the 50-year storm. The choice of coating system was largely dictated by the abrasive effects of sea-ice. The external surfaces of the pile were coated with 350 µm ceramic reinforced epoxy.

Three separate coating systems had been specified:

- Submerged Zone: 300 µm DFT, applied as 2 x 150 µm.
- Splash Zone: 300 µm DFT applied as 3 x 100 µm.
- Atmospheric Zone: 240 µm DFT applied as 2 x 120 µm.

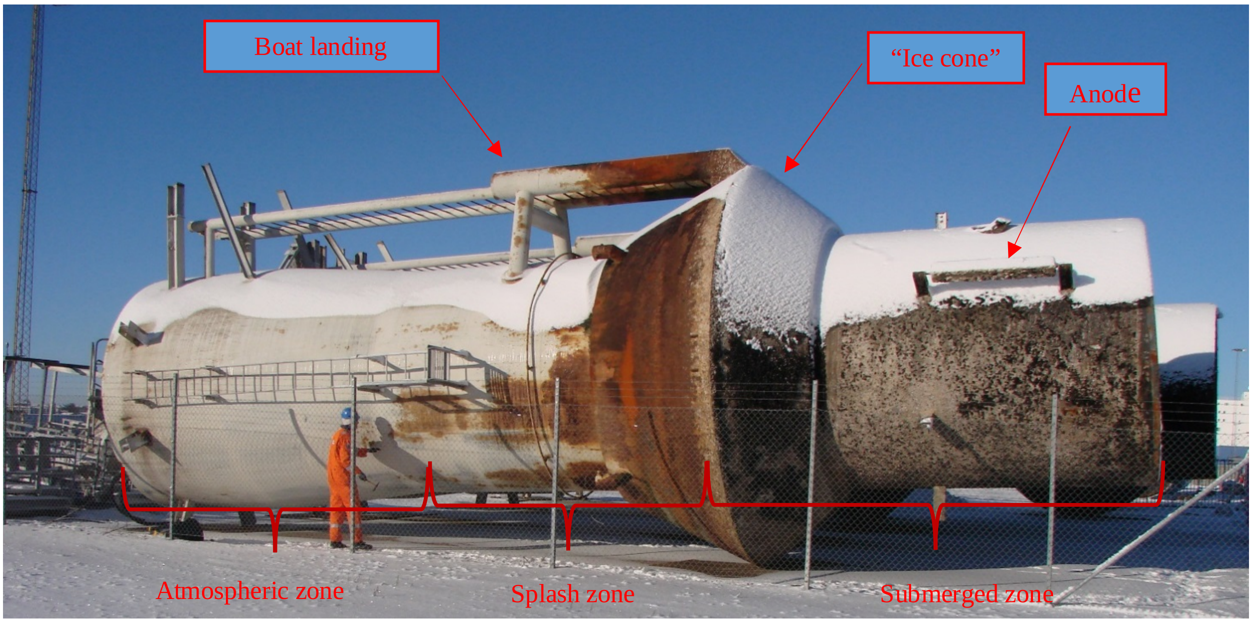

Figure 6. A decommissioned monopile (2016) from Yttre Stengrund in the Baltic Sea.

In the submerged zone, from the lower part of the ice cone down to the cut area at the sea bed level, the piles were all partly covered with marine fouling (mainly blue mussels and barnacles). In general, there was no corrosion observed in the submerged zone meaning that the cathodic protection had been sufficiently effective during service. The anodes were removed during decommissioning except for one still attached to one of the piles shown on Figure 6. The coating system (appearing with a black colored top coat) showed some blister formation. On areas covered with barnacles and other hard shell marine fouling the coating looked bright due to calcareous deposits.

In the splash zone the coating on the ice cones was generally damaged and partly missing on all the piles and corrosion was on-going. In the splash zone above the ice cone, the coating on the monopiles showed an “erosion pattern”, see figure 7. The erosion is most probably due to the movement of ice during winter. In spite of the use of an abrasion resistant “ceramic epoxy”, significant wear of the coating top layer has occurred during the 15 years of service.

In the atmospheric zone, the coating system in general appeared in good condition on all piles.

Figure 7. Erosion pattern of the top layer of the coating system in the splash zone.

Despite the fact that the coating system used on the monopiles in the Baltic Sea (Yttre Stengrund) was similar to the coating system used on Horns Rev 1 (the North Sea), the performance of the system used in the Baltic Sea was acceptable. One explanation to this is the different environment. In the Baltic Sea the water is more brackish, i.e. low saline water, and the cold climate with temperatures on an annual average somewhat lower than those in the North Sea may have contributed to the lesser corrosion. Another explanation could be that the paint used on Yttre Stengrund may not have had the same issues regarding poor dispersion of the pigments as seen in the paint for the structures in the North Sea. On the other hand, the Baltic Sea has sea ice during winter, exposing the coating systems on the monopiles to a higher mechanical wear than expected in an ice free environment.

Example 2.
Another inspection included a decommissioned jacket from an oil and gas platform from the North Sea. After 40 years' service, the overall condition of the corrosion protection system was still good. The inspection was made while the jacket legs were cut down, allowing access to all immersed surfaces, both inside and outside.

The glass flake polyester coating in the splash zone appeared to be intact over most of the surface. The adhesion was good when tested by scribing the surface with a slag hammer, Figure 8. The dry film thickness was measured in the range from typically 2 to 5 mm, however in some areas slightly lower.

The only region revealing considerable, but not critical, corrosion was located in the lower part of the splash zone coating, Figure 9. The observed corrosion appeared to be the result of cathodic shielding due to the presence of an additional pipe section installed on the outside. This is a useful observation for evaluating the potential effect of inadequate corrosion protection in gaps or cavities of complex structures.

Figure 8. Inspection of jacket legs from a 40-year old platform at a decommissioning yard. Good adhesion of splash zone coating is observed by scribing with a slag hammer.

Figure 9. Corrosion on jacket leg in an area that originally had been shielded. The corrosion depth is 2-3 mm.

COST REDUCTIONS OF THE SUPPORT STRUCTURES

Construction, installation and maintenance of offshore wind turbines and their foundations is, due to the difficult accessibility, tremendously expensive. The typical repair costs are a factor of 100 times greater than that of similar repair on land. At the same time, such structures are located in the most corrosive environment under heavy influence of wind, weather, fouling and strong sea currents. Due to the current oil and gas trends a cost reduction of renewable energy is likewise an increasingly important parameter. Until now much focus from turbine manufactures has been directed to cost reductions of the turbine itself. It must however be realized that an offshore turbine is typically only responsible for approximately ¼ of the service lifetime cost. Costs associated with other elements such as foundations, installation and maintenance of offshore farms, are currently responsible for more than half the service lifetime cost. These costs must be reduced in order for the industry to reach competitive advantage compared to e.g. fossil fuels. Cost reduction is therefore strictly necessary if offshore wind energy is not just to become a transition technology based on subsidies.

To bring down production costs of monopile and jacket structures, automated processes and the use of standard components have been proposed. A novel jacket foundation concept includes the use of standard pipes from the line pipe production, and selected corrosion protection systems already in use at the pipe manufacturers.[17] At the same time this new concept aims at extension of the "useful service life" of corrosion protection systems, from now 20 years to future 25 years, which equals the service lifetime of the wind farm. It is expected that this new system will reduce the cost of the support structure with 40 % in 2020. A large test of new coating systems for splash zone and immersed service is ongoing, including Fusion Bonded Epoxy (FBE) systems.[18]

CONCLUSIONS

After more than 15 years' service life of the first large offshore wind farms in the North Sea, mostly positive experiences are reported on the condition of the protective coating systems.

In this paper experiences from site inspections of offshore wind farms in operation and from decommissioned constructions have been discussed. The trends seen in the offshore wind segment are requirements for corrosion protection being extended to at least 25 years' maintenance-free service lifetime. This fact is also reflected in newly issued and coming standards where extended pre-qualification tests (such as long-term field exposure for 5 years, abrasion, impact and color retention tests) are included in order to convince owners and certifiers that new coating systems may actually have 25 years' maintenance-free service lifetime. On the other hand, this paper also suggests that pre-qualification tests alone do not necessary pull out the right coating systems for real service. The lifetime of a coating system also highly depends on the quality of surface preparation, the coating thickness and the quality of workmanship. At the same time, these factors are usually the most uncertain elements and require strict QC during production.

One might think that the demand for extended service life and at the same time the wish for cost reductions point in opposite directions. This is not necessary the reality:

- More QC during the coating process will extend the service lifetime of the coating system and thereby also reduce the overall costs for corrosion protection.
- Learnings from extended pre-qualification tests go hand in hand with real life experiences from site inspections of constructions in operation and constructions being decommissioned. The experience from both scenarios will continuously help optimizing the coating systems needed for wind offshore service and help in updating standards and guidelines to make extended service lifetime for offshore wind structures possible.
- Novel concepts bringing in automated production processes and application of standard components might be tools to improve production quality and thereby extending the useful service life of the coating system, and at the same time bringing down production costs.

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