
The Cost of Corrosion in the Oil & Gas Industry

An Italian oil and gas exploration and production company found a way to quantify its corrosion costs in order to find ways to reduce them.

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he cost of corrosion cannot be overemphasized. Much research and writing has been done to evaluate and quantify the direct and indirect costs of corrosion. However, the conclusions of this work are very often qualitative and general.

Corrosion costs are significant, particularly in the oil and gas industry. These costs are expected to increase due to the development of fields in more aggressive environments (i.e., deeper wells with higher temperatures, higher pressures, and higher concentrations of carbon dioxide, hydrogen sulfide, and chloride; and wells in deeper offshore locations).

Oil and gas companies are working to quantify corrosion costs, which often are hidden under expensive items such as loss of production, unforeseen events, or maintenance in order to evaluate their impact on the company budget and to reduce them.

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(left) Typical offshore platform in the Adriatic and Mediterranean seas.

(right) Tiffany platform, part of T-Block in the North Sea.
Photos courtesy of Agip

In this regard, Agip S.p.A., an Italian company engaged in the exploration, development, and production of oil and natural gas in various parts of the world, began a study several years ago designed to better control corrosion and to reduce its cost. The first step of the study was to collect information from engineering and production activities.

The Owner's Experience

The owner, which is based in S. Donato Milanese, Italy, owns and operates approximately 250 facilities—petrochemical plants and offshore platforms—worldwide. These facilities are a constant source of data and information that are analyzed to monitor the impact of corrosion.

Typical offshore platform in the Adriatic and Mediterranean seas.
Photo courtesy of Agip

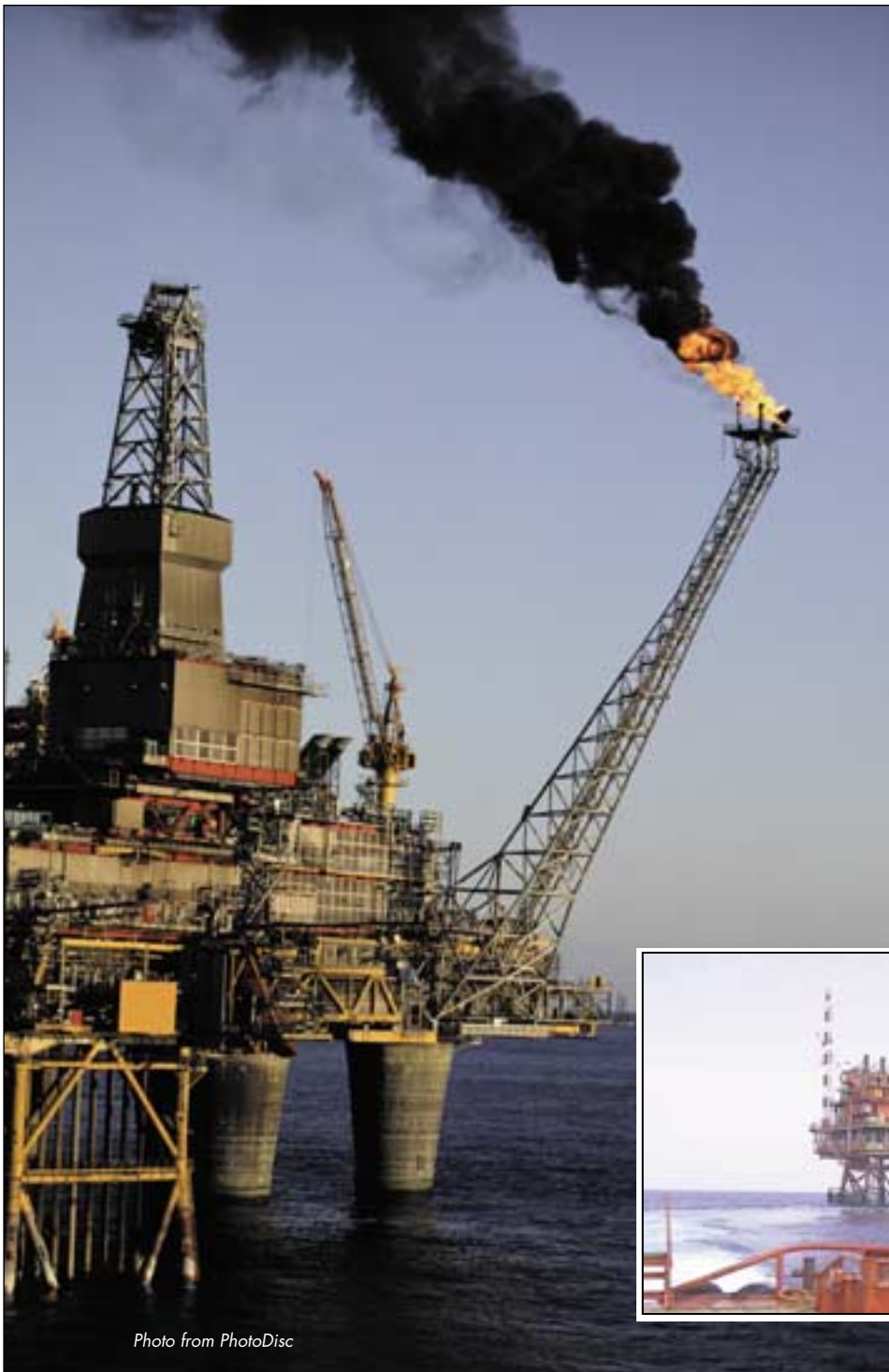


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This article summarizes some of that information, with particular reference to two offshore facilities. In addition, it presents information on the protective coating program implemented by the offshore facility owner for effective painting cost control as well as efforts made to review, update, and implement a suitable painting specification.

This article compares the data of two offshore facilities—T-Block, which comprises three oil fields, and the Bouri Field. They were selected because they are located in different environments—the North Sea and Mediterranean Sea, respectively—which means the approach to corrosion prevention during design and service maintenance is different for each of them.

**Table 1
T-Block Field—Corrosion Capital Expenditures for the Platform**

Platform (Jacket and Deck)	Corrosion Cost	%
Coating splash zone and deck	\$2,430,000	8
Corrosion allowance	\$1,320,000	4
Cathodic protection	\$5,470,000	18
CRA and chemical injection system for process and services modules	\$21,290,000	70
Total platform	\$30,510,000	100%

**Table 2
T-Block Field—Corrosion Capital Expenditures for the Sealines**

Sealines	Corrosion Cost	%
Flexible flowline, Toni-Tiffany	\$10,730,000	45
Cladded flowline, Thelma-Tiffany	\$10,770,000	45
Coating, export sealine	\$1,100,000	4.7
Corrosion allowance, export sealine	\$1,090,000	4.6
Cathodic protection, export sealine	\$180,000	0.8
Total sealines	\$23,870,000	100%

Corrosion-related capital expenditures (CAPEX) and operating expenditures (OPEX) are presented for each facility. In addition, all coating applications for T-Block are listed.

T-Block

T-Block is located in the UK sector of the North Sea. It includes three fields: Tiffany, with a fixed platform, and Toni and Thelma, with subsea wellheads. Production started in 1994 with Tiffany and Toni. At the end of 1996, the average oil output was 64,000 barrels (bbl)/day.⁷

Due to the presence of carbon dioxide (20%) and hydrogen sulfide (80 ppm) in the produced crude oil, corrosion-resistant alloys (CRA) and coatings were installed over large portions of all the production facilities. In an offshore environment, corrosion also is a concern for the outside of the facilities due to the aggressiveness of seawater.

Tiffany platform is a jacket with eight legs. It is 134 m (4,400 ft) high and weighs 16,900 tons. It is cathodically protected by sacrificial anodes and coated entirely with epoxy systems: a solvent-free material applied to a dry film thickness (DFT) of 1,000 µm (40 mils) on the splash zone and an inorganic zinc primer, epoxy polyamide, and fluoropolymer-based enamel (255 µm [10 mils]) for the structure and areas above the splash zone.

Tiffany platform has seven oil-producing wells and four water injection wells. Toni and Thelma fields have nine oil wells and three injection wells. The seawater injection wells have carbon steel tubings internally coated with an epoxy system. The flowlines for the transportation of the crude to the platform are externally protected with an epoxy coating as well.

The process module includes equipment for separation, gas compression and dehydration; a natural gas liquid recovery unit; and water injection equipment. CRA are used here for separators and piping.

Table 3
T-Block Field—Corrosion Capital Expenditures for the Wells

Well Tubings	Corrosion Cost	%
Tiffany production (7 wells in CRA*)	\$2,390,000	29
Toni production (4 wells in CRA)	\$2,385,000	29
Toni water injection (3 wells coated)	\$375,000	4
Thelma production (5 wells in CRA)	\$3,080,000	38
Total tubings	\$8,230,000	100%

*Corrosion-resistant alloys

Table 4
T-Block and Bouri Fields—Comparison of Corrosion CAPEX Distribution (%) by Cost Element

Corrosion CAPEX%	T-Block	Bouri
Corrosion-resistant alloys	82	54
Cathodic protection	8	23
Coatings and paint	5	11
Corrosion allowance	3	11
Inhibition equipment	2	1
Total	100%	100%

The water injection deoxygenation vacuum tower is coated with an epoxy system.

From Tiffany platform, two sealines export oil and gas. These 12- and 10-inch (30- and 25-cm) pipelines are cathodically protected by aluminum anodes and coated with coal tar enamel.

Tables 1, 2, and 3 show the capital expenditures for corrosion control in 1996 costs (US\$). These CAPEX are shown for the platform (Table 1), sealines (Table 2), and wells (Table 3).

The cost of corrosion is actually only the extra cost of protection due to corrosion. For example, the difference between CRA materials and carbon steel, which would have been used if corrosion did not exist, is considered a cost of corrosion. The three tables show coating costs to be 8% of the total expenditures for corrosion control for the platform (jacket and deck), 4.7% for the sealines, and 4% for the wells tubing.

The T-Block corrosion OPEX in the first two years of production are mainly

due to inspection and maintenance activities. The very short period of service and the selection of CRA materials to prevent corrosion account for the low OPEX. Annual painting maintenance costs are \$35,000.

The corrosion CAPEX of \$73 million, including the cost of well completions not shown in Tables 1, 2, and 3 (e.g., tubings, wellheads, downhole equipment), compared to the total T-Block capital expenditures of \$1.1 billion are equal to about 6.6%.

This percentage varies and reflects the corrosivity of different environments. The percentage of CAPEX due to corrosion of export sealines is about 3.5% (based on coating costs of \$2.37 million and total costs of sealines of \$67.175 million [not shown]). This value is low because oil and gas have been separated from water, resulting in low corrosivity. For the platform, the value is about 4% (dollar amounts not shown). For the flowlines, the percentage of corrosion CAPEX reaches 25% (e.g., the

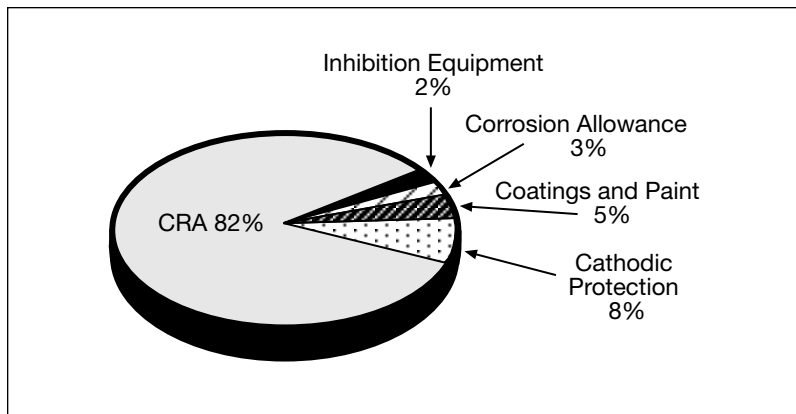


Fig. 1 - Corrosion-related capital expenditures (CAPEX) for Tiffany Platform

cost of the Toni-Tiffany line is \$10.73 million, while the total cost of the flowline is \$42.5 million [not shown], because of the transportation of the unseparated, highly corrosive fluids.

In Fig. 1, the corrosion CAPEX are presented in terms of cost elements. The primary importance of CRA materials, which account for 82% of corrosion CAPEX, is evident. The percentage of the other elements is approximately equivalent. This allocation of expenditures for protection systems in Fig. 1 is the result of life-cycle cost evaluation. The evaluation was performed by taking into consideration the risk of corrosion, which showed that the total costs (very high CAPEX and low

OPEX) were actually lower when compared to the results derived from other, less conservative material selection.

Corrosion CAPEX may be divided into internal and external corrosion protection. Because of the corrosivity of the produced fluid, 84% of all expenditures are dedicated to internal corrosion protection.

Bouri Field

Bouri Field is located in the Mediterranean Sea. It includes two production platforms and a single point mooring (SPM) connected to a floating production storage offloading (FPSO) facility with total jackets weighing 45,400 tons. There are 35 oil wells. The average oil production is 90,000 bbl/day.

Background: Corrosion in the Oil and Gas Industry

Much published information is available about the problem of corrosion damage in the oil and gas industry. Following are references to some significant reports.

- In 1993, it was estimated that 60% of all maintenance costs for North Sea production platforms were related to corrosion either directly or indirectly.¹
- A recent analysis was made by the U.S. Department of Transportation on pipeline incidents

(i.e., spills, leaks, or failures) in the United States.² The DOT's database contains only events that resulted in a release of gas, a fatality or injury, or damage exceeding \$50,000. Of the 865 incidents reported from 1985–1994, 138 occurred offshore. Corrosion (mainly internal) was recorded as the primary cause, accounting for 41% of the incidents. Of the 727 onshore incidents, corrosion accounted for 20%, second only to external force causes at 45%.

- A report on inspection findings of several offshore production plants shows that corrosion was a factor in 35% of the structures, 33% of the process systems, and 25% of the pipelines.³
- The gas pipeline industry purchases an estimated \$80 million in coatings each year in North America to coat new pipelines and to recoat existing pipelines.⁴ ○

Comparison of T-Block and Bouri Field

Table 4 compares the corrosion CAPEX for T-Block and Bouri according to cost elements.

The differences between the two fields are apparent. For Bouri Field, the presence of three structures results in higher costs of cathodic protection, coatings, and corrosion allowance than for T-Block.

On the other hand, CRA costs are high in both fields because of the high corrosivity of the produced crude oil.

In addition, OPEX expenditures for maintenance painting at Bouri Field are very high (\$1.8 million average per year), whereas for T-Block they are low, as noted, because of its short service period and its use of CRA materials for corrosion prevention.

The Facility Owner's Approach to Preventing Corrosion

Based on these two offshore facilities, here is the owner's approach to optimizing the cost of corrosion control by protective coatings and the fundamental principles of its protective coatings program.

Considering the severe service conditions of offshore facilities and the difficulties of periodic maintenance painting for a service life of 20-25 years, it is essential to carefully prepare the painting specification before construction.

The target of the owner's corrosion prevention program is to optimize the initial coating costs on the basis of design life of the facility and, during service, the maintenance painting costs for the remaining life.

Many factors influence the effectiveness and cost efficiency of a coating maintenance program, but the owner maintains that if design and construction procedures are not properly considered, field expendi-

tures and profitability can be substantially affected.

Therefore, it considers the following points to be fundamental components of an effective cost control program for corrosion prevention by protective coatings:

- proper design and specification;
- coating selection;
- quality assurance/quality control (QA/QC) during construction, repair of damages after transportation and installation, and systematic ongoing maintenance;
- periodic condition and monitoring surveys of the facilities; and
- data and case history collection.

Other fundamental principles include intended coating life expectancy, type of exposure, ease of maintenance, design to minimize corrosion and repair during fabrication, and the paint specification.

Intended Coating Life Expectancy

The primary consideration for a coating system on new facilities is its capability to provide the longest possible service life. However, decommissioning an offshore facility with a coating in perfect condition would be considered excessive. (In that case, perhaps the selected paint system performed better than expected and a less expensive system could have been used instead.) For platforms near the end of their producing life expectancies, critical cost factors such as time requirements for decommissioning an offshore facility, working hours, equipment, and materials take priority over the condition of the coating systems and their capability to assure long corrosion protection.

Type of Exposure

Each coating system must be suitable for its intended service conditions. (For example, high-temperature items need high-temperature coatings, decks need abrasion- and impact-resistant coatings, splash zone areas need longer lasting coatings than upper el-

evations.) Resistance to chemicals such as caustic drilling fluids, cleaning agents, and hydrocarbons such as grease and glycol must be carefully considered.

Ease of Maintenance

Even when a good paint system is applied during construction or refurbishment, it is subject to damages that will require repair. Therefore, maintenance of a coating should be practical, easy, and cost-effective both immediately after application and during service.

Design To Minimize Corrosion and Repair during Fabrication

Good initial design and good repair of fabrication defects can reduce future maintenance painting expenditures by minimizing areas prone to corrosion damage and related coating failures. Sharp edges, rough welds, welding spatter, welding flux, surface laminations, skip welds, back-to-back angles, beams, bolts, and other surface ir-

regularities must be properly treated or removed to assure suitable performance of the paint system and to avoid premature coating failures. Repair of damages to newly installed equipment and modules during construction of offshore facilities is especially important to prevent premature rust formation and increased maintenance painting costs.

The Paint Specification

For a successful and cost-effective painting program, the specification should require the use of proven paint products and systems, which should be applied and inspected according to industry standards. The specification should be considered a legal document that provides the technical rules for the painting project and covers the following topics: scope of work, materials to be used, surface preparation, items to be coated, application, performance standards, safety, inspections, paint systems, pre-job conference, and related components of the

Agip's Coatings for Pipelines, Tubings, and Platforms

Subsea Pipelines

The total length of Agip's subsea pipelines in Italy is 740 km (440 miles). They are mostly gas pipelines. The first one was installed in 1964.⁵

Before 1983, these sealines were externally coated with bitumen products. Fusion-bonded epoxy coatings then were used from 1984 to 1986, and an external coat of epoxy tar reinforced with a glass fiber cloth also was added. Since 1987, polyurethane tar has been

Agip's standard coating for offshore pipelines.

Flexible pipes are often used to connect subsea wells to the platform. They have external thermoplastic material sheathing for protection against corrosion.

Tubings

Tubings are pipes that conduct fluids from the formation to the surface in the case of producing wells or vice versa in the case of injection wells.

In water injection wells, the water is highly corrosive because of the presence of salt (seawater) and oxygen at high temperatures. Coatings are needed to protect the internal surface of the carbon steel tubings. In recent years, Agip has used epoxy phenolic systems for some of these applications. An advantage of these coatings is less friction on the liquid, which results in pumping energy savings.⁶

Application of coatings for production tubings can be limited by

project. The specification should be written to be clearly understood by everyone involved in the project.

Functional Specification of the Facility Owner

The owner's Functional Painting Specification (Protective Treatments and Galvanizing) is the main component of its protective coating program.

A functional specification defines property requirements of coatings for offshore structures, living modules, onshore and offshore production plants, machinery and packages, electrical components, and instrumentation. Examples of such property requirements might be non-skid coatings for decks of offshore structures, fire-retardant coatings for living modules, and color-coded coatings for production areas.

The owner's first functional specification, which was developed more than 20

years ago, has been revised approximately every two to three years. In 1997, in light of new products, paint systems, surface preparation methods, environmental rules, and industry standards affecting the protective coatings industry, the facility owner decided to review and update its functional painting specification.

The program has three components: 1) definition of coating materials and paint systems, 2) review of the painting specification, and 3) criteria for selection of painting contractors.

The final document must satisfy the following requirements:

- be applicable both to new construction and maintenance works;
- be applicable to worldwide facilities onshore and offshore in different environments;
- be a comprehensible and easy "tool" for any company person involved in protective coatings work worldwide; and
- be easy to review and to keep up to date.

operating temperatures and concentrations of corrosive gases (CO₂ and H₂S). Nevertheless, the low cost of coated carbon steel compared to corrosion-resistant alloys makes coatings a very attractive alternative.

Offshore Platforms

The jacket—the immersed structure of offshore platforms—is usually cathodically protected by sacrificial anodes, while splash zones are coated with one coat of solvent-free, high-build epoxy at 1,000 micrometers (40 mils) dry film thickness (DFT).

The Agip platforms in the Adriatic Sea are medium size (700 tons). The coated surfaces per platform are, on average, 10,500 sq m

(114,000 sq ft) for the decks and 2,000 sq m (22,000 sq ft) for the jackets.

In 1993, the average painting cost of a new platform in the Adriatic Sea was calculated at \$393,000 for the jacket and deck. Maintenance painting costs were approximately \$140,000 per platform. Current prices for surface preparation, application, handling, coating materials, etc., for platforms in the Adriatic Sea are as follows.

- Splash zone area—blast cleaning to Sa 3 (SSPC-SP 5), White Metal, and application of one coat of solvent-free epoxy at 1,000 micrometers (40 mils) DFT: \$35/sq m (\$3/sq ft)
- Areas above splash zone—blast cleaning to Sa 3 (SSPC-SP 5) and

application of one coat of inorganic zinc primer at 75 micrometers (3 mils) DFT, one coat of epoxy polyamide at 25 micrometers (1 mil) DFT, one coat of epoxy polyamide at 125 micrometers (5 mils) DFT, and one finish coat of fluoropolymer-based enamel at 30 micrometers (1.2 mils) DFT: \$26.50 to \$30.00/sq m (\$2.40 to \$2.70/sq ft)

- Helidecks and non-skid working areas—blast cleaning to Sa 2½ (SSPC-SP 10), Near-White Metal, and application of a solid polyurethane non-skid coating system mixed with polyethylene particles 1 mm (40 mils) in diameter at 2,000 micrometers (80 mils) DFT: \$53/sq m (\$4.80/sq ft) ○

Definition of Coating Materials and Paint Systems

Many factors must be considered when selecting and specifying the best coating system for an intended service. It is not always true that the best and most expensive paint system and the best application procedure provide the most economical solution.

In the owner's Functional Painting Specification, coating materials and paint systems are selected and defined for each specific facility area. Products are described by generic name, and paint systems are listed in a standard form along with their minimum laboratory test requirements.

All tests must be performed according to European standards (EN, UNI, BS, DIN) or to ISO standards. Other standards (NACE, ASTM, SSPC) can be used

when the EN or ISO standards do not meet the needs of a specific requirement. Use of international laboratories certified by EAL (European Cooperation for Accreditation of Laboratories) is encouraged.

The screening tests of the paints and paint systems allow for evaluation of their performance and comparison of their characteristics. Testing is open to all paint manufacturers, but only those that meet the requirements obtain the owner's approval of their coatings and paint systems.

Painting Specification Review

A complete review of the painting specification was considered necessary for the following reasons:

- to conform with changes in paint systems resulting from recent environmental rules (e.g., increased use of solvent-free, waterborne, glass flake, and surface-tolerant systems) and technological developments (e.g., hydrojetting, metallizing, etc.);

- to conform with procedures outlined in recent industry standards for surface preparation, application, inspection, and final acceptance of new construction and maintenance work;

- to compare and evaluate, using all practical means, old and new paint systems to minimize risk of premature failures and to choose the most cost-effective ones; and

- to include criteria concerning maximum allowable levels of water-soluble salt contamination before coating application based on sensible limits of acceptance and use of recog-

nized field methods for detecting contaminants.

The owner's specification of coating materials is a closed specification, which means use of products defined as "similar" or "equal" is not permitted. When a manufacturer changes a product formulation, the coating material and its associated paint system must be retested and reapproved for specification.

Painting Contractor Selection

Selection of qualified painting contractors is always an important step for successful and timely paint application, especially in offshore maintenance operations where the logistical difficulties and high costs of

The owner's coating specification is a "closed specification." Use of products defined as "similar" or "equal" is not permitted.



Typical offshore platforms in the Adriatic and Mediterranean seas.
Photo courtesy of Agip

painting work require strict adherence to pre-established work schedules. Contractors must be able to provide experienced, skilled, and qualified personnel and all the necessary equipment for surface preparation, application, and inspection work to meet the specification requirements. It would be desirable for a painting contractor certification program to be implemented in Europe, similar to the one established in the United States by SSPC: The Society for Protective Coatings to help ensure quality performance in the work of surface preparation and coating application.⁸

Expert Systems

Use of computerized expert systems is valuable for comparing large amounts of data and variables in the selection of ever-increasing options in coating materials and

paint systems, for calculating the benefits of different alternatives, and ultimately for saving time and money.

The owner has provided for the development of two expert systems for its own use to support its oil and gas corrosion control engineering operations.

One system, which is called APEX⁹, was developed over a two-year period in 1995 and 1996 for corrosion control of pipelines in onshore and offshore environments. The other system, for corrosion control of plants and equipment, is still under development.

One section of APEX in particular deals with selection and optimization of external coatings and pipeline joints. Selection is based on environmental corrosivity, intrinsic properties of coatings, and requirements for laying pipeline. It provides information about optimum coatings and technical ranking for applicable coatings,

recommended joint types, optimum coating features, and cost comparisons for applicable coatings.

Conclusion

Selection of the best coating system is critical in any construction and maintenance program. Use of an expert system for this purpose can help reduce time and costs, while a clear and functional painting specification, written according to major international standards, is essential for the success of any cost-effective painting program.

Based on its experience with T-Block and Bouri Field, the owner found that

- coating costs are a high percentage of total costs, even in the presence of CRA materials;
- CRA material costs themselves are high when dealing with high fluid corrosivity; and
- corrosion CAPEX increase with corrosivity (which naturally is high in offshore facilities), while OPEX are proportional to the age of the oil field.

The economic impact of corrosion is estimated by Agip to be approximately \$0.40 per barrel of oil produced. □

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