Module 4

Offshore Structures: Strength, Stability and Corrosion Control Strategies

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Contents

1. Introduction

This module describes the structure of offshore oil and gas and wind turbine generator platforms. Technically, offshore structure platform design and construction are a hybrid of steel structure design and harbor design and construction.

The number of engineering faculties that focus on offshore structural engineering, including the design of offshore platforms are few and this is in-part due to the relatively small number of offshore structural projects in comparison to steel land-based structural projects. In addition, offshore steel structure construction depends on continuous research and study drawn from around the world.

Offshore structures have other special economic and technical characteristics. Economically, offshore oil and gas structures are dependent on oil and gas production, which is related to global investment and this is in turn affected by the price of oil. For example, in 2008 oil prices increased worldwide and as a result many offshore structure projects were started during that time period.

The module begins with a brief history of offshore structures and later covers corrosion prevention strategies employed on offshore platform structures. These strategies have much commonality with the strategies described in earlier modules that dealt with the protection of vessels. The material relating to wind turbine generators and wind farms is covered in slide section 4b though here again, there is a large overlap between structure and corrosion prevention strategies for offshore oil and gas platforms.

2. Brief History of Offshore Structures

As early as 1909-1910, wells were being drilled in Louisiana. Wooden derricks were erected on hastily built wooden platforms that had been constructed on top of timber piles.

Over the past 40 years, two major types of fixed platforms have been developed: the steel template, which was pioneered in the Gulf of Mexico (GoM), and the concrete gravity type, first developed in the North Sea. Recently, a third type, the tension-leg platform, has been used to drill wells and develop gas projects in deep water. In 1976, Exxon installed a platform in the Santa Barbara, CA, channel at a water depth of 259 m (850 ft). Approximately two decades earlier, around 1950, while the developments were taking place in the GoM and Santa Barbara channel, the BP (British Petroleum) company The water depth there is less than 30 m (100 ft) and the operation has grown steadily over the years.

The three basic design requirements for a fixed offshore platform are:

1. The ability to withstand all loads expected during fabrication, transportation, and installation.
2. The ability to withstand loads resulting from severe storms and earthquakes.
3. The ability to function safely as a combined drilling, production, and housing facility.

The importance of the second requirement, and the need to reevaluate platform design criteria, was highlighted in the 1960s, when hurricanes caused serious damage to platforms in the GoM. In 1964, hurricane Hilda, with wave heights of 13 m and wind gusts up to 89 m/s, destroyed 13 platforms. The next year, hurricane Betsy destroyed three platforms and damaged many others. Because Hilda and Betsy were “100-year hurricanes,” designers abandoned the use of “25- and 50-year storms” and began designing for the more destructive 100-year storms.

2.1 Overview of Oil and Gas Field Developments

Estimates of global oil reserves, based on geological and geophysical studies and oil and gas discoveries as of January 1996, indicate that about 53% of the reserves are in the Middle East, a politically troubled region. Overall, 60% of reserves are controlled by the Organization of Petroleum Exporting Countries (OPEC). Obviously, OPEC and the Middle East are very important for the world’s current energy needs.

Most researchers believe that the major land-based hydrocarbon reserves have already been discovered and that most significant future discoveries will be in offshore areas, the Arctic and other difficult-to-reach areas of the world.

Geological research indicates why North America, northwest Europe and the coastal areas of West Africa and eastern South America appeal' to have similar potential for deep water production. During very early geological history, sediments were deposited in basins with restricted circulation and were later converted to the super-source rocks found in the coastal regions of these areas. The presence of these geological formations is the initial indication of the presence of hydrocarbons, but, before feasible alternatives for producing oil and gas from a field are identified and the most desirable production scheme is selected, exploratory work defining the reservoir characteristics has to be completed. First, geologists and geophysicists assess the location’s geological formations to determine if it has potential hydrocarbon reserves.

After the geologists and geophysicists decide that a field could be economically viable, further exploratory activities are undertaken to prepare cost, schedule and financial return estimates for selected exploration and production schemes. After that, the various alternative schemes are compared and the most beneficial one is identified.

During this phase, due to the absence of detailed information about reservoir characteristics, future market conditions and field-development alternatives, experts make judgments based on their past experience and on cost and schedule estimates based on data available from previous history. The success of oil and gas companies depends on this expertise, so most companies keep experts on hand and compete with each other to recruit them. Sometimes, the experiential data are not enough, so decisions are made as a result of brainstorming sessions attended by experts and management, and these are greatly affected by a company’s culture and past experiences.

The reservoir management plan is affected by the characteristics of the fluid the reservoir produces, the reservoir’s size and topography, regional politics, company and partner culture and the economics of the entire field-development scheme. Well system and completion design are affected by the same factors that affect the reservoir management plan, except perhaps the political factors. Platforms, facilities for processing and production, storage systems and export systems are affected by all these factors as well.

The field-development scheme has to take into account:

- Reservoir characteristics
- Production composition (e.g., oil, gas, water, H_2S)
- Reservoir uncertainty

- Environment (e.g., water depth)
- Regional development status
- Technologies available locally
- Politics
- Partners
- Company culture
- Schedule
- Equipment
- Construction facilities
- Market
- Economics

If the preliminary economic indicators in the feasibility study phase are positive, seismic data generation and evaluation, done by geophysicists, follow. These data comprise reasonable information about the reservoir's characteristics, such as its depth, spread, faults, domes and other factors, and an approximate estimate of the recoverable reserves of hydrocarbons.

If the seismic indications are positive and the decision is to explore further, exploratory drilling commences. Depending on water depth, the environment and what's available, an appropriate exploration scheme is selected. A jack-up exploratory unit is suitable for shallow water depths. In water depths exceeding 120 m (400 ft), ships or semisubmersible drilling units are utilized.

At depths of 300 m (1000 ft), floating drilling units require special mooring arrangements or a dynamic positioning system. A floating semisubmersible drilling rig is capable of operating in water as deep as 900-1200 m (3000- 4000 ft).

Exploratory drilling work follows the discovery well. This generally requires three to six wells drilled at selected points of a reservoir. These activities and production testing of the wells where oil and gas are encountered give reasonably detailed information about the size, depth, extent and topography of a reservoir, such as the fault lines, impermeable layers, etc., and its recoverable reserves, viscosity (API grade), liquid properties (e.g., oil/water ratio), and impurities, such as sulfur or another critical component.

Reservoir information enables geologists and geophysicists to estimate the location and number of wells that will be required to produce a field and the volumes of oil, gas and water production. This information is used to determine the type of production equipment, facilities and the transport system needed to produce the field.

Obviously, the accuracy of reservoir data has a major effect on the selection of a field-development concept. In marginal or complex reservoirs, reliable reservoir data and the flexibility of the production system in accommodating changes from the reservoir appraisal are very desirable.

3. Types of Offshore Platforms

The types of fixed offshore platforms are:

- Drilling/well-protector platforms
- Tender platforms
- Self-contained platforms (template and tower)
- Production platforms
- Quarters platforms
- Flare jacket and flare tower platforms
- Auxiliary platforms
- Bridges
- Heliports

Each of these platform types has its own unique characteristics from a functionality point of view.

3.1 Drilling/Well-protector Platforms

Oil and gas wells are drilled from this platform, so the rig will approach this platform to drill new wells or to perform any work over the life of the platform. Platforms built to protect the risers on producing wells in shallow water are called well protectors or well jackets. Usually a well jacket serves from one to four wells.

3.2 Tender Platforms

Tender platforms are not used as commonly now as they were 40 years ago. Tender platforms function as the drilling platform, but the drilling equipment rests on the Usually, platform topside. Nowadays it is common to use a jack-up drilling rig, which does not rest on the platform deck.

With tender platforms, the derrick and substructure, drilling mud, primary power supply and mud pumps are placed on the platform.

As mentioned, since tender platforms are not used much anymore, they will not be encountered in new designs or new projects, but they may be encountered in existing structures, so you must be familiar with them in order to perform assessments for an existing drilling platform.

Figure 1 shows a tender platform. It is shown with two beams along the platform deck length; the beams are used as a railway to the tender tower above the deck for drilling activity.

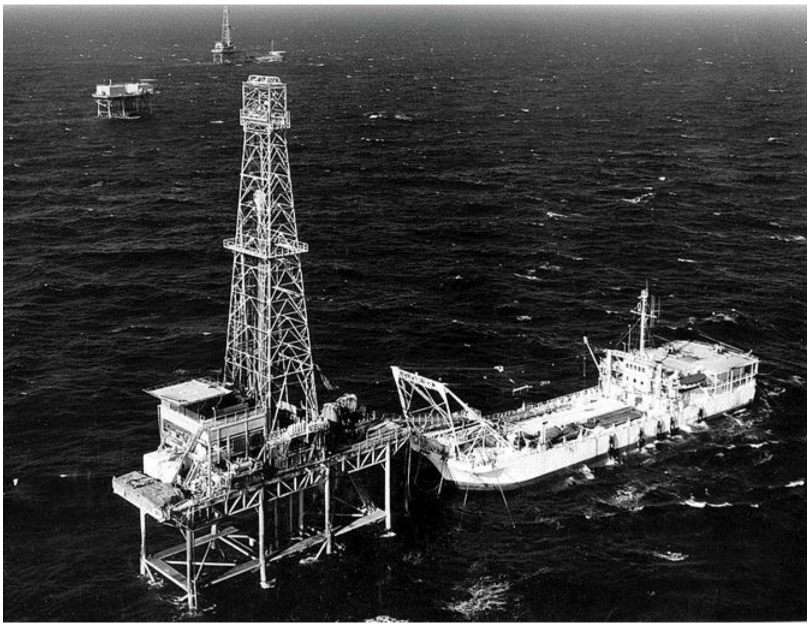


Figure 1. Tender Offshore Platform Rig, Off Louisiana Coastline

3.3 Self-contained Platforms

The self-contained platform is large, usually with multiple decks that have adequate strength and space to support the entire drilling rig with its auxiliary equipment and crew quarters, and enough supplies and materials to last through the longest anticipated period of bad weather when supplies cannot be brought in. There are two types of self-contained platform: the template type and the tower type.

3.4 Production Platforms

Production platforms support control rooms, compressors, storage tanks, treating equipment and other facilities.

Figure 2. Germany's largest oil production platform, Mittelplate-North Sea

Figure 2 shows a production platform carrying the separators and other facilities for production purposes.

3.5 Quarters Platforms

The living accommodations platform for offshore workmen is commonly called a quarters platform.

3.6 Flare jacket and Flare Tower Platforms

A flare jacket is a tubular steel truss structure that extends from the mud line to approximately 3 - 4.2 m (10 - 13 ft) above the mean water line (MWL). It is secured to the bottom by driving tubular piles through its three legs.

3.7 Auxiliary Platforms

Sometimes small platforms are built adjacent to larger platforms to increase available space or to permit the carrying of heavier equipment loads on the principal platforms. Such auxiliary platforms have been used for pumping or compressor stations, oil storage, quarters platforms or production platforms. Sometimes they are free standing, and other times they are connected by being braced to the older structure.

3.8 Bridges

A bridge 30-49 m (100-160 ft) in length that connects two neighboring offshore structures is called a catwalk. The catwalk supports pipelines, pedestrian movement or materials handling. The different geometries of bridges are shown in Figure 3 and Figure 4 shows a bridge between two platforms.

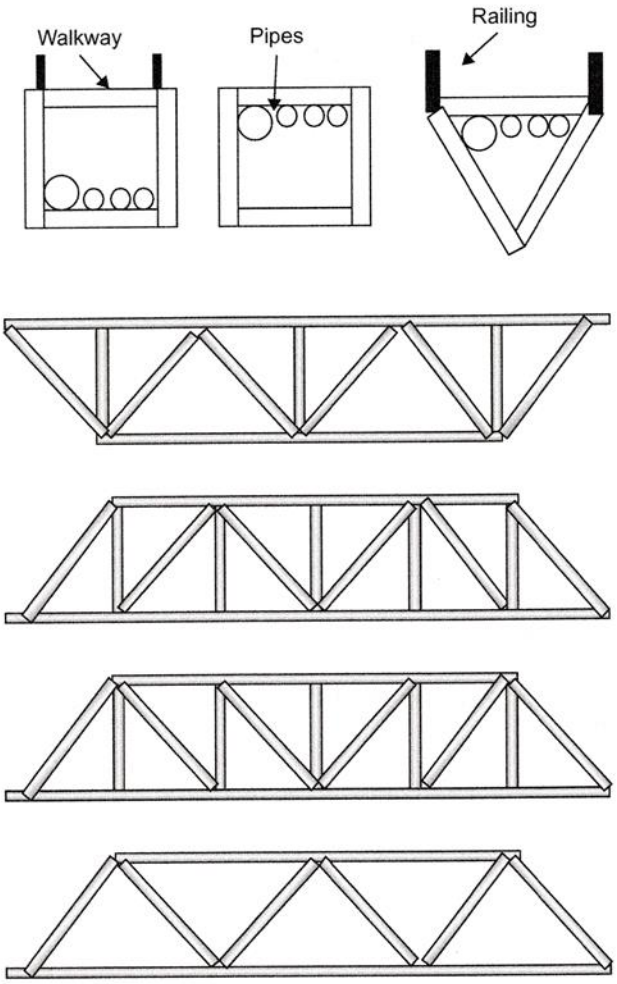


Figure 3. Different Offshore Platform Bridge Geometries and Utility Provision[1]

Figure 4. Bridge between two platforms

3.9 Heliport

The heliport is the landing area for a helicopter, so it must be large enough to handle loading and unloading operations.

A square heliport has a side length of one and a half to two times the largest helicopter's expected length. The heliport landing surface should be designed for a concentrated load of 75% of the gross weight. The impact load is two times the gross weight for the largest helicopter, and this load must be sustained in an area of 24" x 24" anywhere in the heliport surface. Figure 5 shows a heliport platform.

Figure 5. Helideck Adjoining Offshore Platform

4. Types of Offshore Platforms

Different types of offshore structural systems have been developed over time due to the requirements for obtaining oil and gas in locations that have a greater water depth. These types of platforms are as follows.

4.1 Concrete Gravity Platform

The concrete gravity platform shown in Figure 6 is a concrete platform that was constructed in 1997 for Shell.

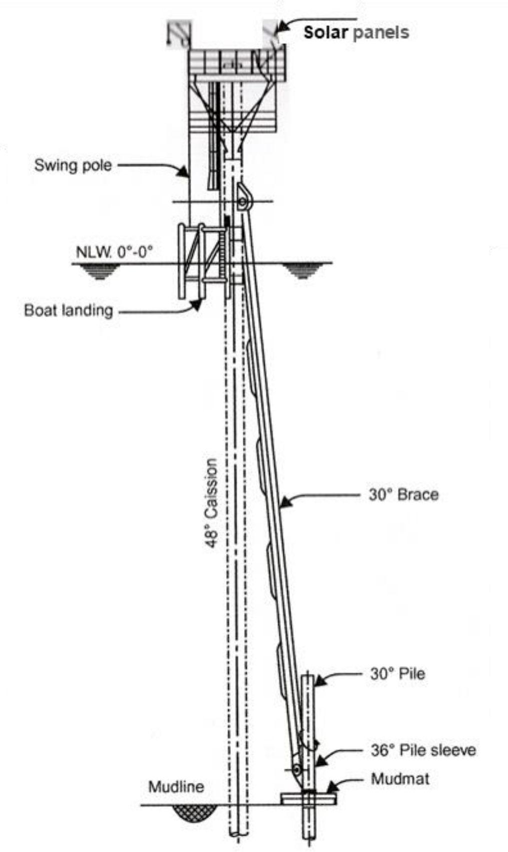
Figure 7 illustrates a complex platform that consists of a production and drilling platform connected by bridges.

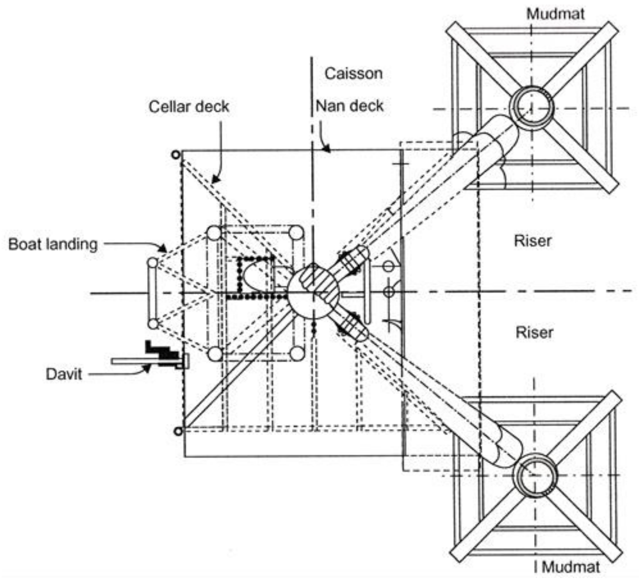
Figure 6. Troll A 'Gravity' Platform – North Sea

Figure 7. Douglas oil complex, Irish Sea off North Wales

In areas where there is a low oil reserve, only one well will be drilled. Many alternatives were devised to address this situation and to obtain the business target. One solution is to have a subsea well that is connected to the nearest platform by a pipeline. This solution is costly, but it is now used widely in deep water.

Another solution is to use a minimal offshore structure, as is shown in elevation and plan views in Figure 8a-b. The concept for this platform is to use the conductor itself as the main support for the small deck. There are also two diagonal pipes that are connected to the soil by two piles, as shown in the elevation view (Figure 8a-b). Figure 9 shows the shape of the topside of this three-legged platform.





(a) (b)

Figure 8a-b. Three-legged Platform (a) Elevation View, (b) Plan View[1]

Figure 9. Photograph of Three-Legged Platform

4.2 Floating Production, Storage and Offloading

The first floating production, storage and offloading (FPSO) platform was the Shell Castellon, built in Spain in 1977. The first conversion of an LNG (liquefied natural gas) carrier (Golar LNG owned the Moss-type LNG carrier) into an LNG floating storage and regasification unit was carried out in 2007 by the Keppel Shipyard in Singapore. In the last few years, concepts for LNG FPSOs have also been launched. An LNG FPSO works under the same principles as an oil FPSO, but it produces only natural gas, condensate and/ or liquefied petroleum gas (LPG), which is stored and offloaded.

FPSO vessels are particularly effective in remote or deepwater locations where seabed pipelines are not cost effective. FPSOs eliminate the need to lay expensive long-distance pipelines from the oil well to an onshore terminal. They can also be used economically in smaller oil fields that can be exhausted in a few years and do not justify the expense of installing a fixed oil platform. Once the field is depleted, the FPSO can be moved to a new location. In areas of the world subject to cyclones (such as northwest Australia) or icebergs (Canada), some FPSOs are able to release their mooring/riser turret and steam away to safety in an emergency. The turret sinks beneath the waves and can be reconnected later.

The FPSO operating at the deepest water depth is the FPSO Espirito Santo of Shell America; it is operated offshore by SBM Offshore N.V. The FPSO is moored in water 1800 m deep in the Campos Basin in Brazil and is rated for 100,000 bpd. The EPC contract was awarded in November 2006 and was scheduled for first oil production in December 2008. The FPSO conversions and internal turret were done at the Keppel Shipyard in Singapore and the topsides were fabricated in modules at Dyna-Mac and BTE in Singapore.

4.3 Tension-Leg Platform

Nowadays there is a trend to use gas that in the previous 40 years would have been burned off in the air, so there are many projects aimed at discovering gas for production, and gas exploration has been extended into deep water. The conventional fixed offshore structure cannot be used, so researchers and engineering firms have used the legs of tension wire platforms in deep water.

A tension-leg platform is a vertically moored floating structure normally used for the offshore production of oil or gas, and it is particularly suited for water depths greater than 300 m (about 1000 ft).

The first tension-leg platform was built for Conoco's Hutton field in the North Sea in the early 1980s. The hull was built in the dry-dock at Highland Fabricator's Nigg yard in the north of Scotland, with the deck section built nearby at McDermott's yard at Ardersier. The two parts were mated in the Moray Firth in 1984. The Magnolia extended tension-leg platform was con-structed for a water depth of over 1425 m (-4700 ft).

Figure 10 summarizes the different types of platform structures, their water-depth range and their functions. Note that water-depth ranges change over time, as new research and development allow construction in deeper water.

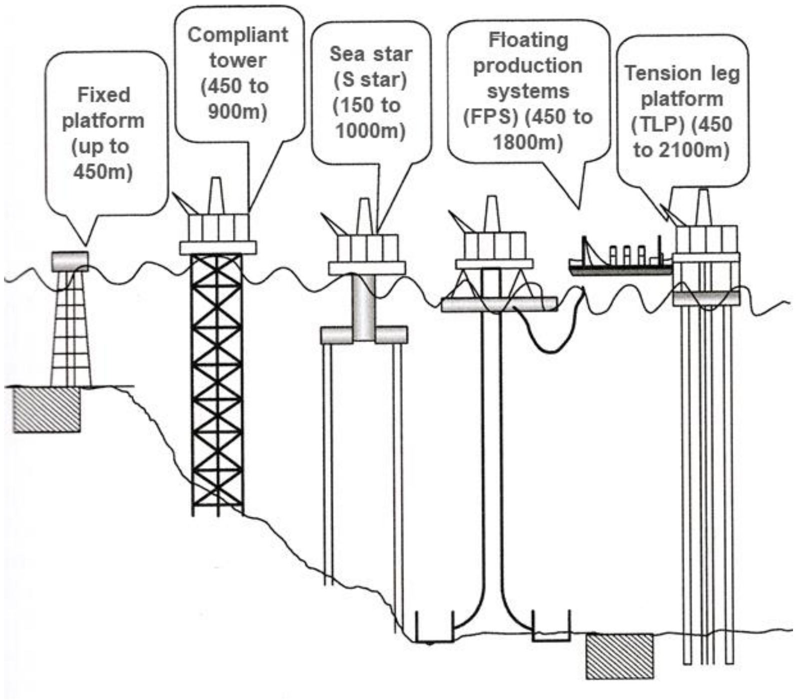


Figure 10. Types of Offshore Platform Structures

4.4 Minimal Offshore Structure

The minimal offshore structure was created about 25 years ago, in response to demand for production companies to investigate low-volume reservoirs. The minimal structure consists of one conductor for oil production that is also used as a pile and on the other hand, a lot of platforms constructed over the years are minimal offshore structures, formed by one pile and using the conductor itself as a support, two additional inclined members as a support for the pile. Furthermore, in the last 20 years many projects have used concrete gravity platforms fabricated from reinforced concrete, and there is a lot of research into these platform types.

Besides the types of offshore structures that are used in oil and gas projects, we need to focus on the economics and policy decisions that guide and direct the projects.

Worldwide, the relationship between multinational companies in the petroleum industry and the countries that have oil and gas reserves is usually in the form of an agreement. It is just as important for structural engineers to focus on this relationship as on stresses, strain, structural analysis, codes and design standards, which are the main elements of the structural engineer's job, but not all that their job entails. Creation of a structural configuration that matches the engineering office's knowledge and capability with the owner's expectations is also a big factor. The contractors, the engineering firm and the engineering staff from the owner's organization have to be on the same page to achieve the owner's target and goals.

The organization's target and goals are based on business targets and profits, the expected oil and gas reserve, expected oil and gas prices and the last important factor, the country that owns the land and the reserves. Therefore, the terms and conditions of, and the political situation in, the country will directly affect investment in the project. Consequently, any engineer working on the project should keep in mind an overview of all the constraints on the project, because these constraints affect the engineering solutions, options and alternative designs. In fact, this overview is very important knowledge for all staff, from senior management down to the junior level.

5. Offshore Structure Loads and Strength

Fixed offshore platforms are unique structures since they extend to the ocean floor and their main function is to hold industrial equipment that services oil and gas production and drilling.

Robust design of fixed offshore structures depends on accurate specification, the applied load and the strength of the construction materials used. Most loads that laterally affect the platform, such as wind and waves, are variable, so the location of the platform determines the meteorological ocean data.

In general, the loads that act on the platform are:

- Gravity loads
- Wind loads
- Wave loads
- Current loads
- Earthquake loads
- Installation loads
- Other loads such as impact load from boats

5.1 Gravity Loads

Gravity loads consist of the dead load and live (imposed) load.

5.1.1 Dead Load

The dead load is the platform's own overall weight and, in addition, the weight of the equipment, such as piping, pumps, compressors, separators, and other mechanical equipment, used during operation of the platform. The overall weight of platform structure upper decks (topside) includes the piling, superstructure, jacket, stiffeners, piping and conductors, corrosion anodes, decking, railing, grout, and other appurtenances. Sealed tubular members are considered either buoyant or flooded, whichever produces the maximum stress in a structure analysis.

The main function of the topside components is to carry the load from the facilities and drilling equipment. The weights of the topside components and their percentage of the total are shown for a sample structure in Table 1. Table 2 gives the overall weight of the topside for an eight-legged platform in 91 m of water. In calculating the overall weight of a platform, a contingency allowance of 5% should be used to cover variations in the loads.

Table 1. Weights and Weight Percentages for an Eight-legged Drilling/ Production Platform[1]

		Weight (Tons)	% of Total
1.	Deck		
	Drilling Deck		
	Plate	72	11
	Production Deck		
	Plate	52	7.8
	Grating	1.0	0.16
	Sub Total	**125**	**18.8**
2.	Deck beams		
	Drilling deck		
	Production deck		
	Sub Total	**230**	**34.8**
3.	Tubular trusses	146	22.1
4.	Legs	105	15.9
5.	Appurtenances		
	Vent stack	6	0.9
	Stairs	12	1.8
	Handrails	4	0.6
	Lifting eyes	2	0.3
	Drains	6	0.9
	Fire wall	4	1.7
	Stiffeners	14	2.2
		661	**100**

Virtually all the decisions about the design of a platform depend on the number of jacket legs. Soil conditions and foundation requirements often control the leg size. The function of the jacket is to surround the piles and to hold the pile extensions in position all the way from the mud line to the deck sub-structure. Moreover, the jacket legs provide support for boat landings, mooring bits, barge bumpers, corrosion protection systems and many other platform components. The golden rule in design is to minimize the projected area of the structure member near the water surface in high wave zones in order to minimize the load on the structure and to reduce the foundation requirements.

Table 2. Jacket Weight for an Eight-Legged Drilling/Production Platform in 91m of Water[1]

ID	Component Description	Weight, Ton	% of Total Weight	Sub-system % of Total Weight
1.	Legs			
	Joint can	177	14.6	
	In between tubulars	309	25.4	40
2.	Braces			
	Diagonal in vertical plan	232	19.1	
	Horizontal	163	13.4	
	Diagonal in horizontal plan	100	8.2	40.7
3.	Other framing			
	Conductor framing	35	2.9	
	Launch trusses & runners	82	6.7	
	Miscellaneous framing	2	0.2	9.8
4.	Appurtenances			
	Boat landing	28	2.3	
	Barge bumpers	29	2.4	
	Corrosion anodes	22	1.8	
	Walkways	16	1.3	
	Mud mats	5	0.4	
	Lifting eyes	2	0.2	
	Closure plates	2	0.2	
	Flooding system	7	0.6	
	Miscellaneous	4	0.3	9.5
				100%

5.1.2 Live Load

Live load is the load imposed on the platform during its use; live loads change from one mode of operation to another. They include:

- The weight of drilling and production equipment.
- The weight of living quarters, heliport and other life-support equipment.
- The weight of liquid in storage tanks.

- The forces due to deck crane usage.

The live load depends on the owner's requirements, and normally it is included in the statement of requirements (SOR) or basis of design (BOD) documents. See Table 2.3 for guidelines on live loads.

For general deck area loading, the topside deck structure should be designed for the specified imposed loads (outlined in Table 2.4) applied to open areas of the deck, where the equipment load intensity is less than the values shown.

DNV (2008) states that the variable functional loads on deck areas of the topside structure should be based on the values in Table 2.5, These values are considered guidelines, so they should be defined in the design criteria, which will be approved by the owner. If the owner needs to increase the load more than is noted in the code, it should be stated in the BOD and the detailed drawings should include the load on the deck. In Table 2.5, the loads that are identified for the local design are used for the design of the plates, stiffeners, beams and brackets.

Table 3. Guidelines for Live Loads[1]

	Uniform Load on Beams and Decking, kN/m² (lbs/ft²)	**Concentrated Live Load on Decking, kN/m² (lbs/ft²)**	**Concentrated Load on Beams, kN/m² (lbs/ft²)**
Walkways and stairs	4.79 (100)	4.378 (300	4.44 (1)
Areas over 400 ft^2	3.11 (65)		
Areas of unspecified light use	11.97 (250)	10.95 (750)	267 (60
Areas where specified loads are supported directly by beams		7.3 (500)	

The loads for the primary design should be used in the design of girders and columns. The loads for the global design should be used for the design of the deck main structure and substructure.

From Table 2.5, the wheel loads should be added to distributed loads where relevant. (Wheel loads can be considered as acting on an area of 300 X 300 mm.) Point loads, which should be applied on an area 100 x 100 mm, and at the most severe position, should not be added to wheel loads or distributed loads.

The value of q in Table 2.5 is to be evaluated for each case. Laydown areas should not be designed for less than 15 kN/m^2. The value of/in Table 5 is obtained from:

$$f = min\{1.0,\ (0.5 + 3/\sqrt{A})\} \qquad \text{Equation 1}$$

where A is the loaded area in m^2.

Table 4. Live Loads Based on Structure Member[1]

	Loading, kN/m²				
	Member Category				
Area	**Deck Plate, Grating & Stringers**	**Deck Beams**	**Main Framing**	**Jacket and Foundation**	**Point Load, kN**
Laydown areas	12	10	**a**	----	30
Open deck areas and access hatches	12	10	**a**	**c**	15
Mechanical handling routes	10	5	**a**	**c**	30
Stairs and landing	2.5	2.5	**b**	----	1.5
Walkways & access platforms	5	2.5	**a**	**c**	5 **d**

a For the design of the main framing, two cases should be considered:

- Maximum operating condition: all equipment including future items and helicopter; together with 2.5 kN/m^2 on the laydown area.
- Live load condition: all equipment loads but no future equipment, together with 2.5 kN/m^2 on the laydown areas, and a total additional live load of 50 tons. This live load should be applied as a constant uniformly distributed load over the open areas of the deck.

b Loading for deck plate, grating and stringers should be combined with structural dead loads and designed for the most onerous of the following:

- Loading over entire contributory deck area.
- A point load (applied over a 300 mm x 300 mm footprint).
- Functional loads plus design load on clear areas.

c For substructure design, deck loading on clear areas in extreme storm conditions may be reduced to zero, in view of the fact that the platform is not normally manned during storm conditions. A total live load of 200 kN at the topside center of gravity should be assumed for the design of the jacket and foundations.

d Point load for access platform beam design is to be 10 kN and 5 kN for deck grating and stringers, respectively.

Table 5. Variable Functional Loads on Deck Areas[1]

	Load Design		Primary Design	Global Design
	Distributed Load, kN/m²	**Point Load, kN**	**Apply Factor for Distributed Load**	**Apply Factor to Primary design Load**
Storage areas	q	1.5q	1.0	1.0
Laydown areas	q	1.5q	**f**	**f**
Lifeboat platforms	9.0	9.0	1.0	May be disregarded
Area between equipment	5.0	5.0	**f**	May be disregarded
Walkways, staircases and platform crew spaces	4.0	4.0	**f**	May be disregarded
Walkways and staircases for inspection only	3.0	3.0	**f**	May be disregarded
Areas not exposed to other functional loads	2.5	2.5	1.0	May be disregarded

f is calculated from equation 1 above

Global loads should be established based on the worst-case-scenario characteristic load combinations complying with the limited global criteria for the structure. For buoyant structures, these criteria are established by requirements for the floating position in still water, and intact and damage stability requirements, as documented in the operational manual, are considered for variable loads on the deck and in tanks.

In calculating the dry weight of piping, valves and other structure supports, there should be a 20% increase as a contingency for all estimates of piping weight, because in most cases there are changes in piping dimensions and location during the lifetime of the structure. In addition, all the piping and fittings are calculated in the operating condition, assuming they are full of water with specific gravity equal to 1, with a 20% contingency.

When calculating the dry weight of all equipment, equipment skid, storage and helicopter, a contingency allowance of 10% should be included.

From a practical point of view, Table 6 presents the minimum uniform live load values from industrial practices.

Table 6. Minimal Uniform Loads from Industrial Practices[1]

Platform Deck	Uniform Load, kN/m² (lb/ft²)
Helideck	
Without helicopter	14 (350)
With Bell 212	2 (40)
Mezzanine deck	12 (250)
Production deck	17 (350)
Access platforms	12 (250
Stairs/walkways	4.7 (100)
Open areas used with the equipment operating and piping loads for operating and storm conditions	2.4 (50)

5.1.3 Impact Load

For structural components carrying live loads that could face impact, the live load must be increased to account for the impact effect, as shown in Table 7.

Table 7. Impact Load Factors[1]

	Load Direction	
Structural Item	**Vertical**	**Horizontal**
Rated load of cranes	100%	100%
Support of light machinery	20%	0%
Support of reciprocating machinery	50%	50%
Boat landings	890 kN	200kN

5.1.4 Wind Loads

Wind forces on offshore structures are caused by complex fluid-dynamics phenomena, which are generally difficult to calculate with high accuracy. The most widely used engineering approach to estimate wind forces on offshore structures is based on a few observations as listed below:

- When a stream of air flows with constant velocity (ν), it will generate force on the flat plate of area (A).
- The plate will be placed orthogonal to the flow direction.
- This force will be proportional to ($A\nu^2$).

- The proportionality constant is independent of the area, which is verified by experimental studies.

Hence, the wind force on a plate, orthogonal to the wind flow direction can be determined by the net wind pressure as given below:

$$p_w = \frac{1}{2}\rho_a C_w \mathrm{v}^2$$

where ρ_a is the mass density of air (1.25 kg/m^3), and C_w is the wind pressure coefficient. It is important to note that the mass density of air increases due to the water spray (splash) up to a height of 20-20 m above MSL.

5.1.5 Wave Loads

The theories concerning the modeling of ocean waves were developed in the 19th century, however, practical wave force theories concerning actual offshore platforms were not developed until the 1950s, when the Morison equation was presented and the wave forces on a vertical pipe were shown to be as illustrated in Figure 11.

$F = F_D + F_I$ equation 2

where F_D is the drag force and F_I is the inertia force.

- Drag force: The drag force due to a wave acting on an object can be found by:

  $F_D = 1/2\ \rho C d V^2 A$ equation 3

Where F_D is the drag force (N), Cd is the drag coefficient (dimensionless), V is the velocity of the object (m/s), A is the projected area (m^2) and ρ is the density of water (kg/m^3)

- Inertia force: The inertia force due to a wave acting on an object can be found by:

  $F_I = \pi paCmD^2 / 4$ equation 4

Where F_I is the inertia force (N), Cm is the mass coefficient (dimensionless), a is the horizontal water particle acceleration (m^2/s), D is the diameter of the cylinder (m) and p is the density of water (kg/m^3).

Wave Load Calculation

- The values of Cd and Cm are dimensionless and the values most often used in the Morison equation are 0.7 and 2.0, respectively. API (American Petroleum Institute) recommends 0.65 and 1.6. respectively, for smooth surfaces or 1.05 and 1.2, respectively, for rough surfaces, such as surfaces with marine organism growth

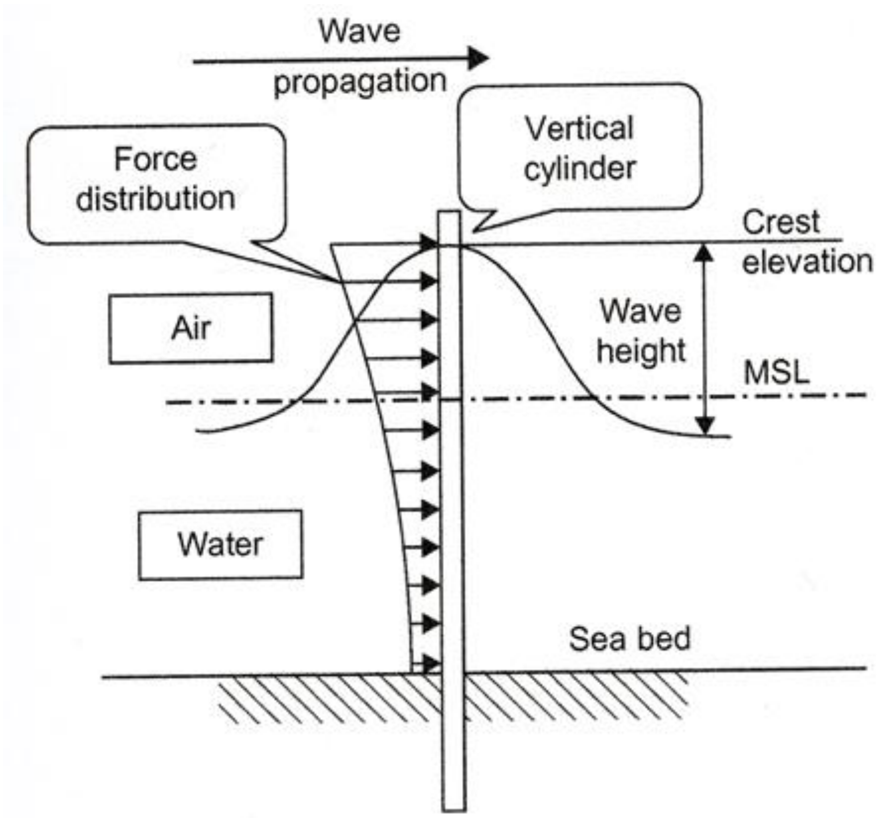


Figure 11. Wave Force Distribution on a Vertical Pipe[1]

5.1.6 Comparison of Wind and Wave Calculations

Calculation of the force affecting the structure due to wind takes the drag force into consideration and neglects the inertia force, but in the case of waves, drag force and inertia force are considered in the calculation. The following example demonstrates the reason for neglecting the inertia force in wind load.

If the platform is oriented as shown in Figure 12, so that the direction of wind is not perpendicular to the faces of the platform, during calculation of the wind load, the angle of inclination of the wind direction to the platform should be considered in each direction

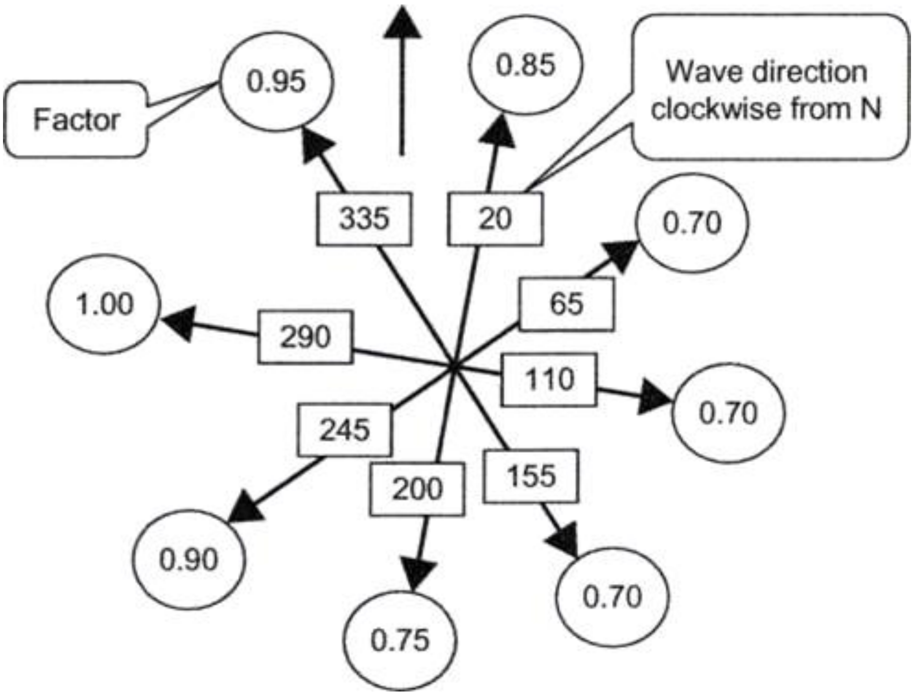


Figure 12. Design for Wave Directions and Factors that Apply to the Omnidirectional Wave Height in GoM[1]

5.1.6.1 Example Calculation of Wind and Wave Loads

Consider a pipe diameter of 0.4m

Data: V_{air} = 25m/s $\quad$ V_{water} = 1m/s

a_{air} = 1m^2/s $\quad$ a_{water} = 1m^2/s

ρ_{air} = 1.3kg/m^3 $\quad$ ρ_{water} = 1000kg/m^3

$$F_D = 1/2\ \rho CdV^2A$$

$$F_I = \pi paCmD^2 / 4$$

For Air:

$$F_D = 1/2\ \rho CdV^2A = (1/2)(0.7)(1.3)(25)^2(0.4) = 113.75\ N$$

$$F_I = \pi paCmD^2 / 4 = 2(1.3)\ \pi(0.4)^2/4(1) = 0.33\ N$$

For Water:

$$F_D = 1/2\ \rho CdV^2A = (1/2)(0.7)(1000)(1)^2(0.4) = 140\ N$$

$$F_I = \pi paCmD^2 / 4 = 2(1000)\ \pi(0.4)^2/4(1) = 251\ N$$

6. Corrosion in Offshore Platforms

6.1 Corrosion in Seawater

The fixed offshore structure platforms in oil and gas projects are exposed to seawater all the time.

The corrosion problems for steel structures in seawater have been well studied over many years, but despite published information on materials behavior in seawater, failures still occur. The concentration of dissolved materials in the sea varies greatly with location and time as seawater is diluted by rivers, rain or melting ice or it is concentrated by evaporation. The most important properties of seawater are:

- Remarkably constant ratios of the concentrations of the major constituents globally
- High salt concentration, mainly sodium chloride
- High electrical conductivity
- Relatively high and constant pH
- Solubility for gases, of which oxygen and carbon dioxide in particular are of importance in the context of corrosion
- The presence of organic compounds
- The existence of biological life, to be further distinguished as microfouling (e.g., bacteria, slime) and macrofouling (e.g., seaweed, mussels, barnacles, and many kinds of animals or fish).

Some of these factors are interrelated and depend on physical, chemical and biological variables, such as depth, temperature, intensity of light and the availability of nutrients. The main numerical specification of seawater is its salinity. Salinity was defined, in 1902, as the total amount of solid material (in grams) contained in one kilogram of seawater when all halides have been replaced by the equivalent of chloride, when all the carbonate is converted to oxide, and when all organic matter is completely oxidized. The 1902 definition was translated into equation (1), where the salinity (S) and chlorinity (Cl) are expressed in parts per thousand.

$$S(\%) = 0.03 + 1.805Cl \qquad (1)$$

The fact that Equation (1) gives a salinity of 0.03% for zero chlorinity was a cause for concern, and a program led by UNESCO helped to determine a more precise relation between chlorinity and salinity. The definition of 1969 produced by the UNESCO study is:

$$S(\%) = 1.80655Cl(\%) \qquad (2)$$

The definitions of 1902 and 1969 give identical results at a salinity of 35% and do not differ significantly for most applications. The definition of salinity was reviewed again when techniques to determine salinity from measurements of conductivity, temperature, and pressure were developed. Since 1978, the Practical Salinity Scale was developed and defines salinity in terms of a conductivity.

The practical salinity symbol S for seawater is defined in terms of the ratio K of the electrical conductivity of a seawater sample at 15°C and the pressure of one standard atmosphere, to that of a potassium chloride (KCl) solution, in which the mass fraction of KCl is 0.0324356, at the same temperature and pressure. The K value exactly equal to 1 corresponds, by definition, to a practical salinity equal to 35.

The corresponding formula is given in Equation (3).

$$S = 0.0080 - 0.1692K^{0.5} + 25.3853K + 14.0941K^{1.5} - 7.0261K^{2} + 2.7081K^{2.5} \quad (3)$$

Note that in this definition parts per thousand (%) is no longer used, but the old value of 35% corresponds to the new value of 35. Since the introduction of this practical definition, salinity of seawater is usually determined by measuring its electrical conductivity and generally falls within 32-35%.

As discussed above, when corrosion occurs, the anodic reaction rate is exactly equal to the cathodic reaction rate. In environments of good conductivity (such as in seawater or seabed mud), the corroding metal displays a single potential that lies between potential at cathode E_c and potential at anode E_a. In Figure 13, this condition is met where the anodic and cathodic curves cross.

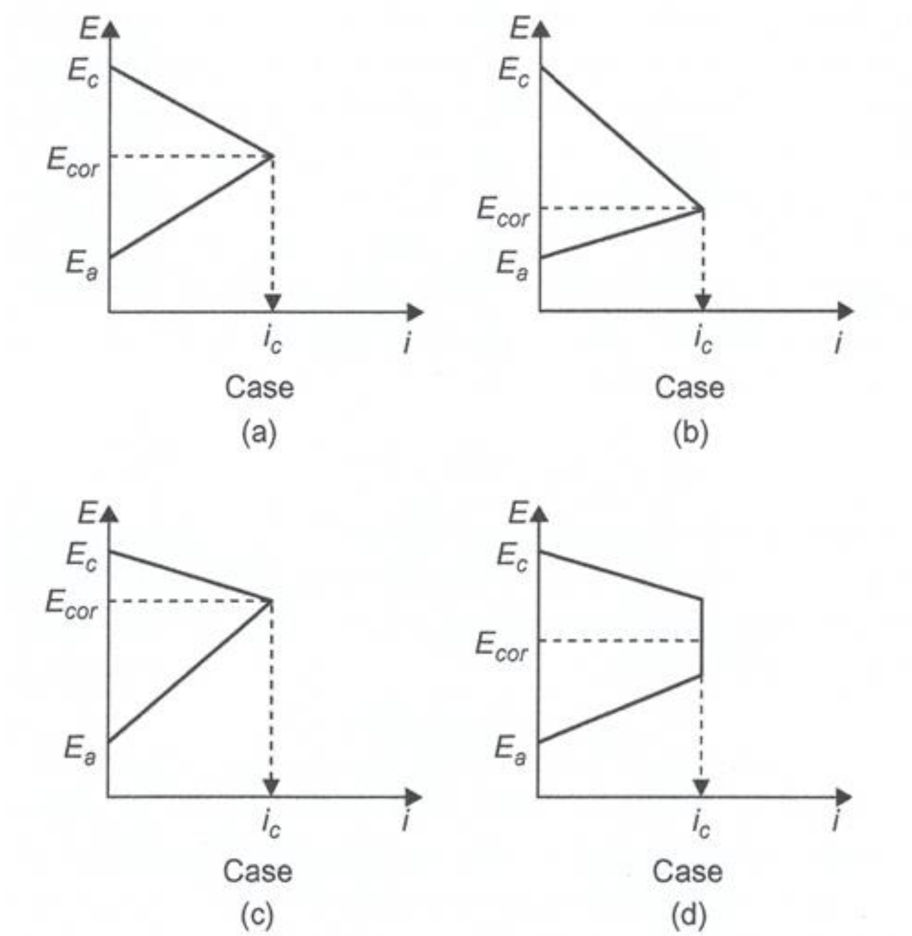


Figure 13. Evans Diagrams[2]

The potential at the crossover point is referred to as the *corrosion potential,* E_{cor}. It is the single potential exerted by a corroding metal referred to above. The current I_{cor} is referred to as the corrosion current, and it is an electrical representation of the corrosion rate. In reality, a corroding metal does not take up potential E_a or E_c but spontaneously moves to E_{cor}.

While the shape of the individual *E*-log *I* curves may vary, depending on environmental conditions, the manner in which the diagrams (*polarization diagrams*) are interpreted, in terms of E_{cor} and I_{cor} remains the same.

Figure 13(a) presents an Evans diagram of the polarization curves for separate anodic and cathodic reactions intersecting at a point where the mean anodic and cathodic current densities are equal and presents the corrosion rate in terms of a mean corrosion current density (I_{cor}).

However, there is always some difference between the electrode potentials developed at anodic and cathodic sites on the metal surface. It may be the amount is significant in ohmic drop (iR drop) under conditions where corrosion macro-cells are formed when the anodic and cathodic areas are separated by a medium of high electrolytic resistance, so the Evans diagram is modified as shown in Figure 13(d).

Therefore, the mean corrosion rate I_{cor} is reduced, and the corrosion potential varies with the location between the limits of anode E_{cor} and cathode *Ecor* with the positions of local anodes being indicated by the region of low corrosion potential. In the absence of significant ohmic drops, the mean corrosion rate (I_{cor}) depends on the magnitude of the difference between the reversible potentials of the anodic and cathodic reactions and on the average slopes of the anodic and cathodic polarization curves. If the anodic reaction is steeply polarized, as in the presence of a passive film, then I_{cor} is small and E_{cor} assumes a value that is close to the reversible potential of the cathodic reaction, as shown in Figure 13(c). On the other hand, if the cathodic reaction is steeply polarized, as in limited oxygen availability, the situation is as shown in Figure 13(b), with I_{cor} again small but the corrosion potential close to the reversible potential of the anodic reaction.

6.1.1 Corrosion of Steel in Seawater

The corrosion of steel in seawater, as well as in seabed mud, can be adequately represented by,

$Fe \rightarrow Fe^{2+} + 2e^-$ (anodic reaction)

$2e^- + H_2O + 1/2O_2 \rightarrow 2OH^-$ (cathodic reaction)

although the process normally proceeds to the precipitation of ferric hydroxide.

On clean steel in seawater, the anodic process occurs with greater facility than the cathodic process. Consequently, the corrosion reaction can proceed no faster than the rate of cathodic oxygen reduction. The latter usually proves to be controlled by the rate of arrival of oxygen at the metal surface, which in turn is controlled by the linear water flow rate and the dissolved oxygen concentration in the bulk seawater.

This may be represented on a polarization diagram, as shown in Figure 14. At first, the cathodic kinetics increase (get faster) as the potential becomes more negative from E_c.

This has the effect of depleting the oxygen immediately adjacent to the metal surface, thus rendering the reaction more difficult. Ultimately a point is reached where the surface concentration of oxygen has fallen to zero and oxygen can then be reduced only as and when it reaches the surface. Further lowering of the potential cannot increase the cathodic reaction rate, because the kinetics are now governed by potential-independent diffusion processes, and a plateau, or limiting, current is observed. Figure 14 shows that the corrosion rate is then equal to this limiting current. The limiting current can be increased by increasing the oxygen flux, either by raising the bulk oxygen concentration (the concentration gradient gets steeper) or increasing the flow rate (the oxygen- depleted layer gets thinner). Both serve to increase the corrosion rate, as shown in Figure 14.

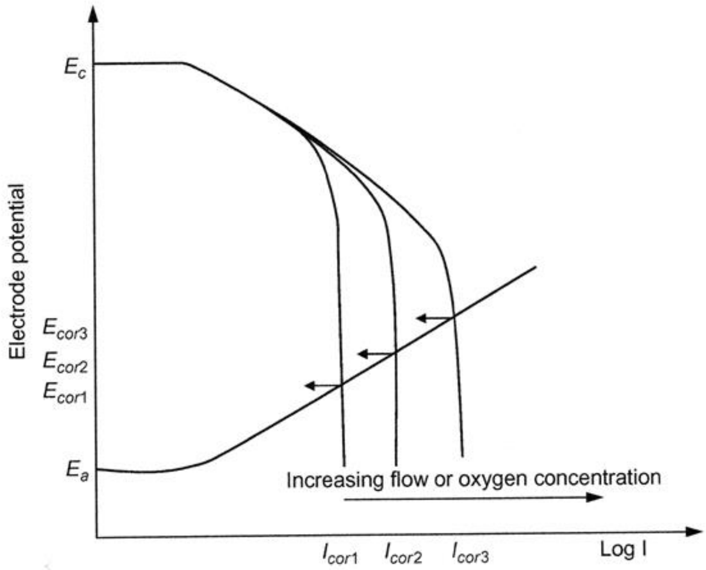


Figure 14. Polarization Diagram with Increasing Oxygen Concentration[2]

To a first approximation, it may be stated that the rate of corrosion of clean steel in aerated seawater under turbulent flow conditions is directly proportional to the bulk oxygen concentration and the linear velocity. Fick's first law of diffusion and the Chilton-Colbourn analogy can be used to calculate the precise effect of oxygen concentration and Reynolds number (flow rate) on corrosion. Accordingly, Ashworth (1994) estimated the maximum corrosion rates of clean steel in North Sea water at 7°C, as shown in Table 8.

In practice, corrosion products and marine fouling build up on steel as it corrodes in seawater, and they generally produce lower corrosion rates.

Rowlands (1994) suggests that the corrosion rate of fully immersed steel is fairly rapid in the first few months of exposure but falls progressively with time.

A value of 0.13 mm/year may be taken as reasonably representative in any part of the world. However, pits may grow at 3 to 10 times that rate.

Many marine structures, particularly those in shallow waters, are simultaneously exposed to a number of discrete corrosive environments: the marine atmosphere, the splash zone, the tidal zone, the fully submerged zone and the mud zone. Commonly, the corrosion rate data are represented schematically, a practice that derives largely from the work of Humble (1949) as shown in Figure 15. Peak corrosion rates are found immediately below the mean low tide zone and in the splash zone. The typical mean corrosion rate in the splash zone, in case of quiet sea conditions, is estimated as 0.25 to 0.75 mm/year.

As shown in Figure 14, the corrosion rate is controlled by sluggish cathodic kinetics: in this case, the rate of arrival of oxygen at the surface and the effect of increasing oxygen availability.

Table 8. Estimated Maximum Corrosion Rates of Clean Steel in North Sea Water at 7°C

Linear Flow Rate, m/s	O_2 Concentration				
	6ppm	**7ppm**	**8ppm**	**9ppm**	**10ppm**
0	0.080	0.094	0.107	0.120	0.134
0.3	0.091	0.107	0.123	0.138	0.154
0.4	0.096	0.111	0.128	0.144	0.160
0.6	0.104	0.121	0.138	0.156	0.174
1	0.120	0.140	0.160	0.179	0.199
2	0.160	0.187	0.213	0.240	0.266
4	0.240	0.280	0.320	0.360	0.400

The peak corrosion rate is often attributed to galvanic action between steel in contact with oxygen-rich surface waters, which is the cathodic area, and steel at somewhat greater depth exposed to waters of lesser oxygen content, which is the anodic area. It is difficult to conceive that the change in oxygen concentration with depth is sufficiently great to cause such an effect, and it may be that other factors come into play. It is essential to gather the following information before starting the design of the cathodic protection (CP) system.

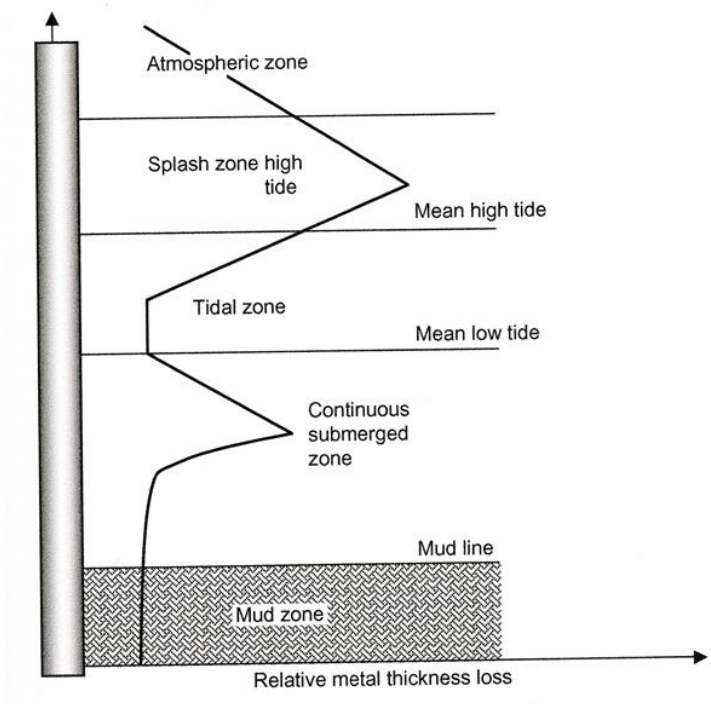


Figure 15. Corrosion Profile of Steel Piling after 5 Years of Exposure[7]

6.1.1.1 Structure Design Data Required (for CP System)

- Design life for the cathodic protection system and the structure
- Construction drawings with full details and dimensions
- General arrangement drawings showing the structure's relationship to the seabed, lowest astronomical tide level (LAT), mean water level, and maximum operational conditions
- Extent of use of, and application of, protective coating
- Availability of electrical power
- Proposed construction schedule
- Structure fabrication methods and fabrication on site
- Any weight limitations/constraints on the installed CP system
- Safety requirements
- Constraints and limitations on the installation and in-service maintenance and monitoring of the CP system
- High-strength steels or other metals used in the structure that may be subject to a reduction in mechanical properties when under cathodic protection

6.1.1.2 Offshore Site Location Data Required (for CP System)

- Water depth, oxygen content, velocity, turbulence, temperature, resistivity, tidal effect and suspended soil
- Chemical composition of water
- Pollutants, depolarizing bacteria or marine borers present in the water or seabed
- Geological nature of the seabed and the probability that scour will occur
- Adjacent facilities, including pipelines, and details of their CP system
- Susceptibility to stratification of the water and the resultant effect on resistivity, temperature and oxygen content
- Performance history of previous or existing CP systems in the same environment
- Protective current density requirements to achieve the applicable protection criteria, obtained from site surveys or reliable documentary sources
- Susceptibility to adherent marine fouling, including type, rate of growth and variation with water depth

6.2 Cathodic Protection Systems

There are three types of cathodic protection system, each of which, when correctly designed, installed and operated, can effectively protect a fixed offshore steel structure for its design life. They are:

i) Sacrificial: anodes cast from reactive metals, usually zinc or aluminum alloys, as they are more electronegative than the structures requiring protection and require no external source of power

ii) Impressed current: anodes manufactured from materials that are essentially inert and powered by an external source of direct current

iii) Hybrid: a mixture of sacrificial anodes and externally powered impressed current anodes.

The principal technical advantages and disadvantages of sacrificial, impressed current and hybrid systems are summarized in Table 9.

The use of the term impressed current system can be misleading, because for most offshore applications, an impressed current system is used in combination with a small number of sacrificial anodes, forming a hybrid system. Sacrificial anodes are provided in hybrid systems to ensure that adequate polarization of the critical nodes is maintained at all times, even if the power supply to the impressed current anodes fails or is switched off temporarily (e.g., to permit manual underwater inspection or cleaning of the structure by divers). Some early impressed current systems were provided with inadequate sacrificial anode back-up and significant corrosion damage was reported in times of unplanned (and planned) impressed current shut-downs.

The same considerations apply equally to jacket structures, with one important addition, namely, that a power source to drive the impressed current system is generally not available until the topside power generation equipment is installed and commissioned. On large deep water jackets in the North Sea, this may be a year or more after installation of the jacket; protection for the interim period is provided by high-current, short-life sacrificial anodes.

It is strongly suggested that designers contemplating an impressed current system for North Sea applications provide full sacrificial back-up, with sacrificial anodes that provide full protection for a minimum of 2 years, plus an allowance for periods of possible impressed current system shut-down during subsea surveys and maintenance throughout the design life.

The hybrid system is used in Murchison and Hutton platforms due to the heavy weight constraints. The CP designers of the Murchison and Hutton platforms in the North Sea carried out detailed assessments of alternative sacrificial and impressed current designs. The assessments revealed that use of the sacrificial anode is essential but that the heavy weight can be reduced by using impressed current systems as the primary means of protection on both platforms, despite their vastly different structural configurations, as Murchison is a deep water conventional jacket but Hutton was the world's first tension-leg platform.

Thus, a main advantage of using hybrid systems over sacrificial systems is weight-saving on Murchison and Hutton platforms. In the case of Hutton, the installed weight of the primary impressed current system, plus supplementary sacrificial anodes located close to the main node joints, was approximately 60 tons. On the other hand, an equivalent totally sacrificial system would have weighed around 250 tons. From a practical point of view, the most economical solution for buoyant structures, such as tension-leg platforms, is the impressed current system, which is different from the solution for the fixed offshore structure platforms.

Table 9. Comparison of Impressed Current CP and Sacrificial Anode CP Systems

	Sacrificial Anode	Impressed Current	Hybrid System
Advantages	Simple, reliable and free from in-service operator surveillance. System installation is simple. Permanent potential monitoring system not essential.	Flexible under widely varying operating conditions. Weight advantage for large-capacity, long-life systems.	Flexible under widely varying operating conditions. Weight advantage for large-capacity, long-life systems.
Disadvantages	Large weight penalty for large-capacity, long-life system. Response to varying operating conditions is limited. Hydrodynamic loadings can be high.	Relative complexity of system demands high level of detailed design expertise. System installation is complex, and it requires a power source. Perceived diver risk from electric shock. In-service operator surveillance required. Permanent potential monitoring system essential. Vulnerable to loss of power. It is not recommended for North Sea without full sacrificial back-up (i.e., part of a hybrid system).	Relative complexity of system demands high level of detailed design expertise. System installation is complex, and it requires a power source. Perceived diver risk from electric shock. In-service operator surveillance required. Permanent potential monitoring system essential.

The relatively simple geometry and large, flat surfaces of buoyant structures are ideally suited for protection to be provided by a small number of high-current, low-voltage, flush-mounted anodes. Cables to reference electrodes and anodes can be easily and economically routed through ballast tanks and human access pathways in the pontoons and columns of the hull.

It is worth mentioning that the impressed current systems may also be cost- competitive for traditional fixed offshore jacket structures with simple geometry, located in relatively shallow water depth. In this case the reference electrode and anode cables will be installed in substantial conduits and routed along the outside of the structural tubular members. But impressed current systems are less likely to be cost-competitive on large jackets of complex geometry located in harsh environments. In case of complex node geometries in the structure jacket, it will be difficult to allow large-capacity anodes to protect all surfaces adequately, because of shielding effects. Moreover, in a harsh environment, it will be difficult and expensive to route anode and reference electrode cables inside the structural tubular members in order to ensure their mechanical safety.

As a general rule, increasing anode operating temperatures causes a decrease in both anode ampere-hour capacity and driving potential; at temperatures exceeding 50°C, zinc alloys experience intergranular corrosion and they should not be used at low anode current densities, and the ampere-hour capacity of aluminium alloys tends to decrease significantly. In order to realize the performance claimed by anode manufacturers and thus to ensure the successful operation of the cathodic protection system, it is imperative that strict quality assurance and quality control of the anode manufacturing process should be achieved and maintained throughout production. (Quality assurance, quality control and tests are discussed below.) The requirements contained in DNV RPB, 401 (2005) are considered the minimum standards for offshore work, with supplementary requirements for specific project applications to be determined and specified by the designer.

6.2.1 Anode Geometry

Sacrificial anodes are generally cast in three basic geometric shapes: the long, 'lender, stand-off type; the flat-plate, flush-mounted type; and the bracelet type. In most cases, anode selection is performed by the owner, taking into account effects like sea current drag and interference with subsea interventions. If the anode type has not been specified by the owner, then the contractor selects the anode type, taking into account such factors as net anode mass to be installed and available space for location of anodes. The anode type further affects the anode utilization factor and the anode current output in relation to weight.

Typical examples of the first two basic geometries are shown in Figures 16 and 17.

The most common anode shape used for offshore structures is the long, slender type with a trapezoidal or circular cross-section with weight about 100 kg. The principal advantages of this anode geometry are high current output and good current distribution for a given mass, noting that a flush-mounted anode with the same net anode mass will have a lower anode current output and lower utilization factor. Another advantage is the simple fabrication and casting requirements.

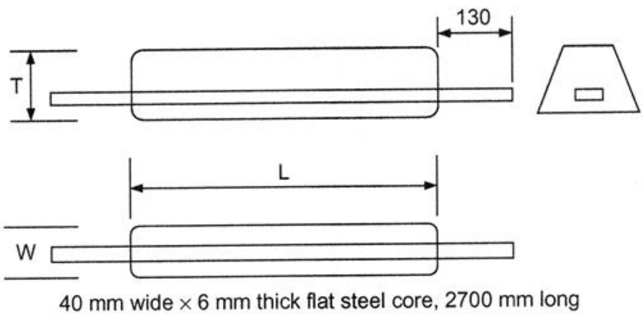


Figure 16. Flush-Mounted Anode

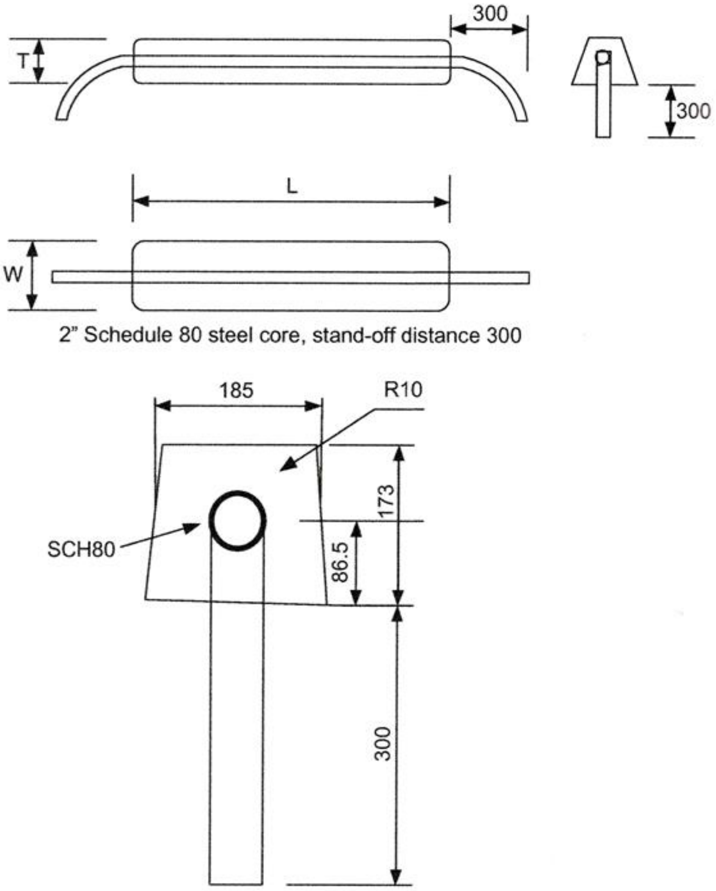


Figure 17. Stand-Off Anode

In general, flat-plate anodes are the best solution to complex fabrications where space limitations prevent the use of larger stand-off anodes or if cathode current densities are low. Examples are heavily reinforced mud mats and large, flat, painted surfaces. The designer should determine if anode shapes can be more economically chosen from a manufacturer's standard units or whether, because of the large number required for a new structure, a preferred design could raise costs. Anode manufacturers offer a large variety of standard anode and insert core types, with the choice of steel inserts usually being among bar, tube or rod, in either straight lengths or prefabricated, weld-jointed shapes.

Stand-off and flush-mounted anodes may further be divided into "short" and "long," based on the length-to-width ratio, as shown in Figure 15 and Figure 16.

The anode type selected is a main factor in anode resistance and utilization, as discussed below.

The slender stand-off type is typically cast on a tubular insert and is used for relatively large anodes (e.g., on platform substructures and subsea templates' The current output, I_a (A), in relation to net anode mass, M_a (kg), is high, as is the utilization factor (μ).

Modem stand-off anodes put the anode in a steel frame, called a sled, and connect it with a special clamp to the steel structure. This system is very easy to install and less costly in retrofitting an existing structure.

Stand-off anodes can be manufactured and obtained up to a net anode mass of several hundred kilograms. In surface waters, drag forces exerted by sea currents are significant.

Bracelet anodes formerly were used primarily for pipelines but now they are used on platform legs in the upper zone, combining a high current-output-to-weight ratio with low drag. All flush-mounted anodes should have a suitable coating system applied on the surface facing the protection object. This is to avoid build-up of anode corrosion products that could cause distortion and eventually fracture of the anode's fastening devices.

Type of anodes and any special requirements for anode fastening should be defined during the conceptual phase of CP design, taking into account forces exerted during installation as well as piling operation and the effect of wave forces during the structure's lifespan. For stand-off type anodes, special precautions may be necessary during anode design and distribution of anodes to avoid impeding subsea operations.

The insert should be structurally suitable for the anode weight and for the forces likely to be encountered during its lifetime, including impact, storm damage, wave action and, possibly, ice. The insert should normally be made from materials that can be welded to the structural steel. The typical grades of steel (BS4360 grades 40A, 43A or 50C, or API 5L grades B, X42 or X52) are usually used.

If anode inserts are fabricated by welding, the latter has to be in accordance with a recognized, quality-controlled standard. Inserts should be prepared by abrasive cleaning to a minimum standard of S BS1706 and follow NACE recommended practice. RP 0387 may be followed.

Aluminum-based anode steel insert specifications are similar to those for zinc, except that the surface must not be zinc coated nor galvanized after cleaning.

Bracelet anodes are the most commonly used type for protection of submarine pipelines, for which their wrap-around construction is ideally suited. They are rarely used on new offshore platform constructions because of their low current-output-to-mass ratio compared to long, slender anodes. However, bracelet anodes do lend themselves to retrofitting on existing structures and to supplementing or replacing the original failed, deficient or end-of-life cathodic protection systems.

7. Corrosion Control

7.1 Protective Coatings

Protective coatings are the most commonly used means of corrosion control. They are the standard means of controlling external corrosion on everything from offshore structures to pipelines and process vessels. They may also be used on storage tank, pipeline, and storage vessel interiors. The reasons for their widespread use include the ease and low cost of application. Most protective coatings are applied by liquid paint systems, but metallic coatings and wraps are also used. Ceramic coatings are used in some industries, but their brittle nature limits their use in oilfield applications.

Liquid coatings can be lacquers, varnishes, or paint. The first two are usually single-phase liquids, but paints, which are more complex, are generally used because of their greater protective qualities. Most paints are based on organic chemistry, but inorganic coatings, e.g. inorganic zincs and thermally sprayed aluminum, are also available and widely used.

Linings are protective coatings that are applied in thicker films, usually 5 mm (0.2 in.) or more. They are usually applied as flexible solid films and find use on the interiors of storage and ballast tanks, process vessels, and large-diameter piping. Their use is relatively limited in oilfield applications.

The associated costs of applying a protective coating system to an existing structure are typically:

- Surface preparation 50%+
- Permits and scaffolding 30-35%
- Materials ≤10%
- Inspection and other costs ≤10%

More expensive coating materials may have longer service lives, and this means that the total costs of protective coatings over the service life of a structure may be lower than if less expensive coatings were to be applied.

7.1.1 Paint Components

The components of paint coatings are pigments, binders, volatile vehicles, and additives.

Pigments are usually inorganic minerals or metal particles. They provide opacity and color, but they also provide corrosion protection. Their low permeability to water and oxygen migration provides the corrosion protection. Maximum protection is provided by paints with high volumes of pigment in the cured paint film. Primer coatings are sometimes named after their pigments, e.g. zinc-rich primers.

Metallic zinc pigments can provide cathodic protection to steel substrates at coating holidays. Aluminum is less likely to provide this protection. Aluminum-pigmented paints have advantages over zinc at higher temperatures, e.g. in flares and on the exteriors of hot piping and process vessels.

Binders are necessary to hold pigment particles together and to provide adhesion to the underlying substrate, either protected metal, in the case of primers, or underlying paint films. Paint coating types are often classified by the binder, e.g. polyurethanes, epoxies, vinyl's, and so forth.

The binder/pigment ratio is an important parameter in determining the effectiveness of a paint film. Too much binder produces high gloss but may produce chalking after environmental exposure. Too little binder means that the pigment will not be adequately wetted, leading to paint film porosity and loss of corrosion resistance. The best corrosion protection is obtained with paints that provide high pigment volumes but still ensure adequate wetting of the pigments.

Volatile vehicles, either water or organic solvents or dispersants, dissolve or disperse the binder and allow the coating to spread. Modern coatings have fewer volatile components due to environmental and health concerns with volatile organic compounds (VOCs).

Some paints cure by evaporation of the vehicle, while others, e.g. epoxies, cure by chemical reactions that form thermosetting polymer binders. The reaction-based coatings tend to have fewer volatile components.

Other constituents added to paints include plasticizers, which lower the brittleness of the cured film, and anti-skimming and anti-settling agents necessary to keep the paint useable after transport before final use.

7.1.1.1 Coating Systems

It is common for coating systems to have several layers that are usually characterized as primers, intermediate or midcoats, and topcoats. It is important that all layers of a coating system are compatible so that interlayer adhesion and unwanted chemical reactions between the layers are avoided. This is normally accomplished by using materials from the same manufacturer for all layers of the coating system[8].

Primers, the first coating to be applied, provide adhesion of the paint film to the substrate. They also provide most of the corrosion protection and, if necessary, are designed so that they can “key” or bond to the outer coats. Some primers will also contain corrosion inhibitors or metallic pigments, usually zinc flakes, which provide some cathodic protection to the underlying steel substrate at coating holidays[8].

Intermediate or midcoats provide a barrier to water passage. They may also smooth out the surface prior to the application of the topcoat. They also serve as bonding interfaces allowing adhesion to both the primer and the topcoat.

Topcoats provide the desired color to the coating system. Unlike the lower coatings, which need to bind to subsequent coatings and are usually rough on a microscopic scale, most topcoats also provide a smooth surface which promotes water runoff.

Environmental regulations associated with VOC have caused many coating manufacturers to alter the chemistries of their products[8].

7.1.1.2 Corrosion Protection by Paint Films

All paint films are permeable to moisture and oxygen to some extent, but their effect on lowering corrosion rate is primarily due to the low permeability of the coatings compared with that of the uncoated environment[9-14]. The barrier concept is shown in Figure 18, which also shows the important properties of the primer, intermediate coat, and topcoat. Inorganic pigments in the primer provide most of the moisture and oxygen ingress barrier effect. Intermolecular spacings in polymers are much larger than in inorganic pigments, and most of the moisture permeates through the organic binders.

No coating system is perfect, and coating holidays, places where the coating is missing or has been removed, are locations where most corrosion occurs. One way to slowing corrosion at coating holidays is to have corrosion inhibitors in the pigment. This idea is shown in Figure 19. Several pigments that have been used for this purpose are listed below:

- Zinc chromate.
- Zinc phosphate - the only pigment on this list no: banned for environmental reasons.
- Red lead.
- Calcium plumbate - contains lead.
- Coal tar.

Concerns with environmental damage have limited the use of corrosion inhibitors in pigments, and the use of chromates, the most effective of these pigments, has been largely replaced due to concerns with heavy metal pollution. Slow-release corrosion inhibitors are intended to release oxidizing agents, which passivate the surface at holidays, but the nonavailability of chromates for this purpose has greatly reduced their effectiveness.

Metallic pigments, either zinc or aluminum flakes, are added as pigments to many primers. They are virtually impermeable to moisture and oxygen migration. Zinc pigments also provide a measure of cathodic protection once the coating is breached. This cathodic protection is greatly reduced if the primer is overcoated, but this is often necessary for color coding or wear resistance reasons. Inorganic zinc primers are not subject to ultraviolet (UV) damage, so there is no need to overcoat them except for the reasons above. Organic zinc primers are also widely used, and they do benefit from overcoats[14]. Figure 20 illustrates the idea of using zinc-rich primers for cathodic protection at coating holidays.

Inorganic zinc (IOZ) and metalized coating primers have greater tolerance than many organic coatings for salt residues on the surfaces being coated. IOZ primers have porous surfaces that require a misty tack coating usually of organic zinc, prior to applying full topcoats usually organic zinc coatings, at holidays and other locations where IOZ coating primers must be repaired.

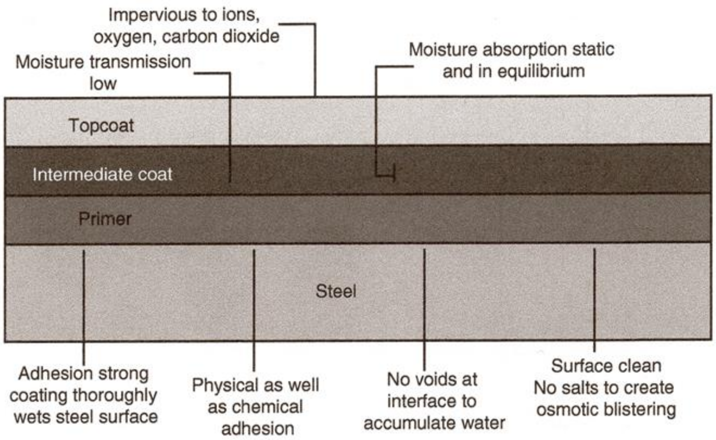


Figure 18. Protective coating system serving as a moisture and oxygen permeation barrier[2]

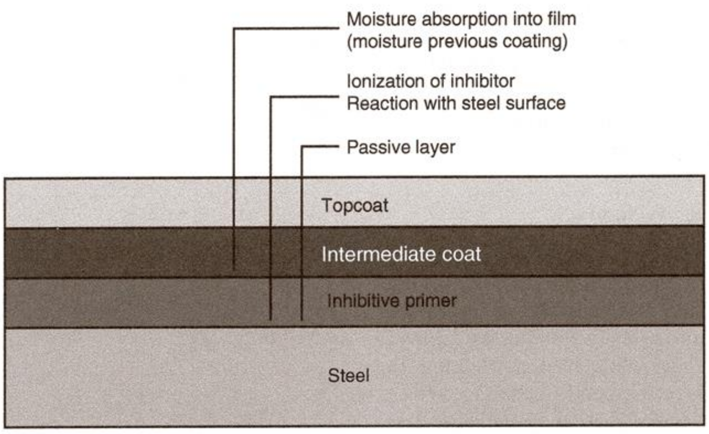


Figure 19. Protective coating system with slow-release corrosion inhibitors in the primer coat[2]

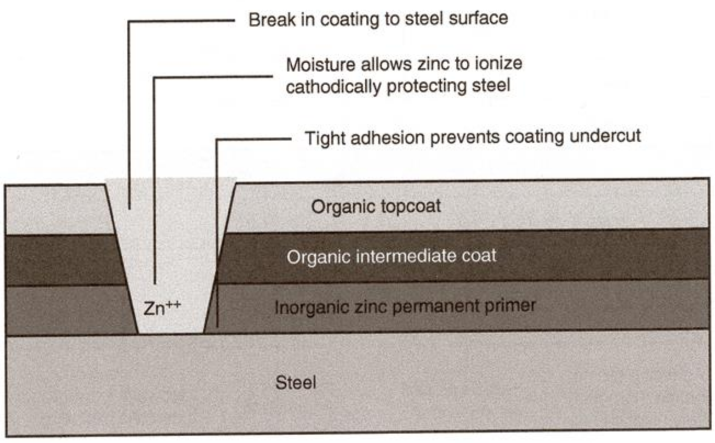


Figure 20. Inorganic zinc primer serving as a source of cathodic protection of the steel substrate at a coating holiday site[2]

7.1.2 Desirable Properties of Protective Coating Systems

In addition to providing corrosion protection, coating systems should also have:

- Strong, durable bonding to the substrate.
- Flexibility, because organic coatings have different coefficients of thermal expansion than metals, and coating flexure is inevitable.
- Toughness or the ability to withstand mechanical shock and loading.

The choice of coating systems often requires compromises between these characteristics. For example, very hard coatings such as those often used on pipeline exteriors are often difficult to repair if damaged in shipping and construction. The necessary bonding to undamaged coatings is hard to achieve. This problem is also apparent at field welds, where organic coatings must be removed prior to welding.

Modern coating systems are generally longer lasting than those that were available in the past. Worker safety and environmental concerns have led to the development of new coatings having higher solids and lower VOC contents. The higher solids content in modern coatings frequently leads to the need for better surface preparation, as many of these coating systems are less tolerant of surface contamination than the systems they are replacing. Electrostatic spraying is an application that was once confined to manufacturing of relatively small items, but recent developments allow for the use of electrostatic spraying in major new construction and rehabilitation. This technique is especially useful on complicated geometries where it is difficult to apply even coatings with other techniques.

7.2 Inhibitors

7.2.1 Water Treatment and Corrosion Inhibition

The most common classifications of water into types used in oilfields are:

- Connate (fossil) water - the original water trapped in the pores of a rock formation during its formation.

- Formation water - water present in the hydrocarbon-producing formation or related rock layers.
- Produced waters - these come from oil or gas wells and can be combinations of formation waters and condensates in various concentrations.
- Injection waters - these are surface waters injected into formations to maintain formation pressures. They contain dissolved solids and treatment chemicals. They may have been processed (filtered and chemically treated) in order to limit corrosion activity in the “down-hole” pipework.
- Condensed waters - these are waters that condense from the gas or oil well as temperatures and pressures change. They have low mineral contents and are often corrosive.
- Meteoric waters - these are waters that have come from surface sources and are normally in the upper layers of groundwater formations.

Connate, formation, produced and injection waters are important to oil and gas production processes.

Surface waters are also classified by their salt contents into:

- Freshwater - low in salt content (<1000 ppm chlorides).
- Seawater - found in oceans and seas; this water 25 usually about 3.5wt% sodium chloride plus significant concentrations of sulphate, magnesium, calcium, potassium, bicarbonate, and other ions. Scale deposits are always possible with seawater, and this can lead to corrosion.
- Brines - have higher salt contents than typical seawater. Most oilfield waters fit into this classification. Barium salts are very persistent in brines and seawater.
- Brackish waters - these are found in bays, estuaries and where major rivers empty into the sea. They are too salty to be considered freshwater, and their composition is intermediate between freshwater and seawater.

Injection waters are necessary to maintain formation pressure and to properly dispose of subsurface waters that have been separated from produced hydrocarbons. Many different source waters are used for injection including seawater, freshwater, produced water, etc. It is important to properly treat injection waters, because any oxygen, bacteria, or scale-forming minerals from the surface can cause souring or plugging of formations.

Figure 21 shows a typical production profile for an oil field. The water production continues to increase for several years after the peak oil production [85]. Worldwide the water-oil ratio (WOR) averages about 3 barrels of water for every barrel of oil, but the figure for the USA where fields are older and production rates have declined are approximately 7 barrels of water for each barrel of oil.

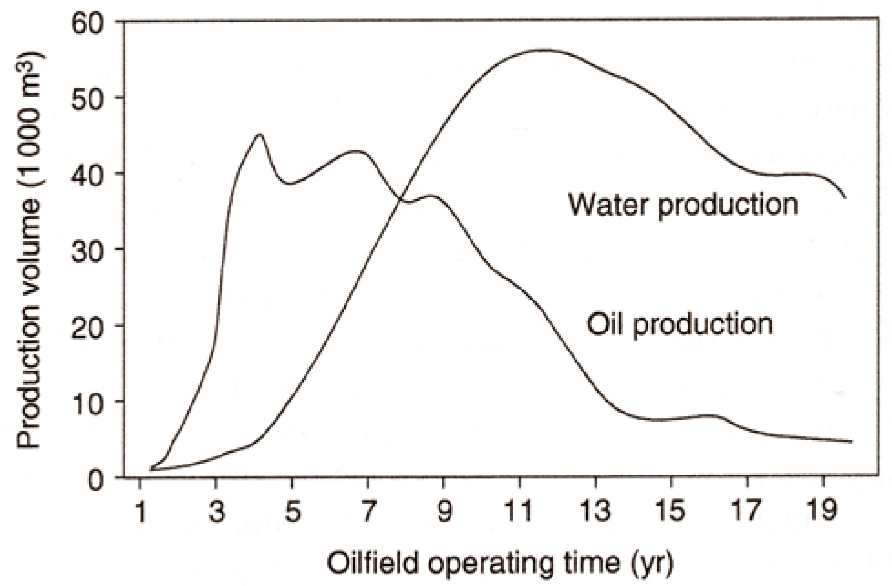


Figure 21. Typical Oil and Water Production Profile for an Oil Field

7.2.2 Corrosion Inhibitors

Corrosion inhibitors are substances which, when added to an environment, decrease the rate of attack by the environment[21-27]. Removal of oxygen, if present, with oxygen scavengers and adjustment of the pH to levels above 10 usually substantially reduces corrosion rates. While these approaches work in many aqueous environments, they are not practical for many production fluids, and the use of corrosion inhibitors, chemicals added to the environment in small concentrations, will often become necessary. These corrosion inhibitors will often reduce the corrosion rate to approximately 5-10 % of the corrosion rate with no inhibitors[21,27].

The use of corrosion inhibitors was the main means of internal corrosion control in oil and gas production until the 1980s, when production from deeper, and consequently hotter, formations led to the increasing use of CRAs for environments where corrosion inhibitors will not work.

Corrosion inhibition can be started or changed in situ without disrupting a production process. This is a major advantage over other corrosion control techniques, and it also means that the inhibitor chemistry or dosage rate can be changed as a field ages and sours or other conditions alter the corrosivity of the environment. Any change should be preceded by an extensive series of tests to ensure compatibility with the process fluid, the pipe work metallurgy, and the existing inhibitor. It has been observed that different inhibitors can “gum up’ when mixed together, and obviously this has considerable implications for corrosion management.

There are many other chemical treatments used for oil-field production fluids, and corrosion inhibitors must be compatible with them. The most common compatibility problems are associated with hydrate inhibitors. Other chemicals used for scale and paraffin control, antifoaming agents, emulsions breakers, etc., also affect corrosion inhibitor performance, but they will be discussed only as they relate to corrosion control.

Types of Inhibitors Corrosion inhibitors have been classified many ways, but one of the most common is into the following groups, based on how they control corrosion:

- Adsorption or film-forming inhibitors
- Precipitation inhibitors
- Oxidizing or anodic passivation inhibitors
- Cathodic corrosion inhibitors
- Environmental conditioners or scavengers
- Volatile or vapor-phase inhibitors

These groupings and others are shown in Figure 22.

Another possible classification is into organic and inorganic inhibitors. Most corrosion inhibitors used for oilfield applications are film-forming organic chemicals, but commercial multicomponent inhibitor packages often contain oxygen and H_2S scavengers and oxidizing agents in addition to the film-forming organic components.

Inhibitors do their work at low relative dosages (often expressed in ppm or quarts per 1000 barrels).

Most oilfield inhibitors work by forming hydrophobic films on metal surfaces. Filming amines, the first of these inhibitors to be widely used in oil and gas production, were developed in the 1930s. Many other organic corrosion inhibitors have been developed since that time. There are a wide variety of commercially available proprietary adsorbing inhibitors on the market. They typically have hydrocarbon chains of C12-C18 with amine groups on the hydrophobic end and some other group on the opposite end.

These thin films do not form new compounds on the surface and are considered to be chemisorbed or physiosorbed - attached to the surface by relatively weak bonds having less energy than would be associated with chemical compound formation. These inhibitors work because one end of the relatively long-chain organic molecule is attracted to electrically conductive surfaces such as bare metals. The other end of the same molecule is either hydrophobic (it repels water) or oleophilic (it attracts oil). This means that the adsorbed inhibitor repels water and avoids water-wetting of the metal surface. This is shown schematically in Figure 23.

Halides, present in most oilfield waters, tend to increase the efficiency of these inhibitors by increasing adsorption of the slightly positive nitrogen groups present on the hydrophobic ends of these molecules. Oxygen is an enemy of organic inhibitor films and can both penetrate films and interfere with film formation.

For this reason, oxygen is generally removed (or prevented from entering) oilfield waters that require inhibition with organic adsorbing inhibitors. Most types will not perform well in the presence of more than 0.5 ppm O_2, or, in some cases, as little as a few parts per billion. Because oxygen is the most important environmental chemical in determining corrosion rates, it is common to rely on oxygen removal, leak controls, and oxygen scavengers for topside corrosion control instead of the use of organic corrosion inhibitors.

Adsorbed inhibitor films are very thin and can be removed by mechanical shear forces if the fluid transport past the surface is too fast. The nature of these filming organic inhibitors is such that they will attach to most solid surfaces, and this means that fluid streams with sand or other solid particles will have reduced inhibitor efficiencies, because the inhibitor will also attach to sand and other particulate matter in the fluid stream.

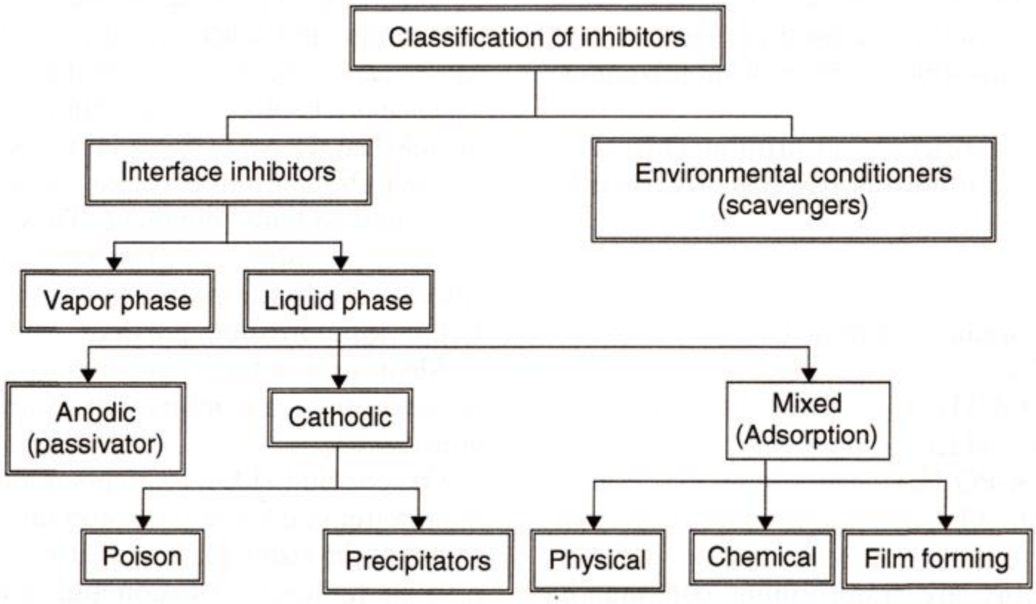


Figure 22. Corrosion Inhibitor Classifications[2]

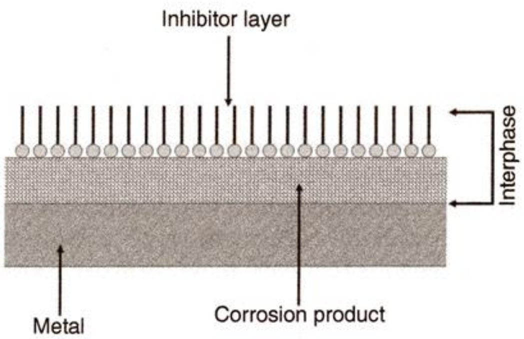


Figure 23. Adsorbing Corrosion Inhibitor with Hydrophobic Molecular Tails away from Metal Surface[2]

Adsorbed inhibitors will also attach to any scale or corrosion products on the surface, and this also diminishes the corrosion-inhibiting effect by increasing the surface area for inhibitor attachment. In older systems that have already corroded, it is essential to clean the surface, mechanically or chemically, before applying inhibitors. If rust or mineral scales are present, acid cleaning may be required. If acid cleaning is attempted, the equipment must be thoroughly rinsed and neutralized before returning the equipment to service.

Adsorbed corrosion inhibitors usually cover both anodes and cathodes. Because these inhibitors are based on organic chemicals, they normally cannot be used at elevated temperatures. The upper limit of their use depends on the chemical involved, but 200 °C (approximately 400 °F) is a common upper limit for the higher-temperature inhibitors, and most filming inhibitors lose effectiveness at much lower temperatures. These inhibitors, which rely on intimate contact with metallic surfaces, cannot be used in combination with oxidizing inhibitors, which form thick metal oxides on the surface.

There are many proprietary adsorption corrosion inhibitors based on the following base chemistries:

- Imidazolines
- Quaternary ammonium compounds
- Amines ($R-NH_2$)
- Carboxyls (R-COOH)
- Thiourea (NH_2CSNH_2)
- Phosphonates ($R-PO_3H_2$)
- Benzonate ($C_6H_5COO^-$)

Precipitating inhibitors are film-forming compounds that form precipitates and cover the metal surface with mineral films that prevent water from reaching the metal surface. Silicates, phosphates, and molybdates fall int: this category. They are used in process water and fine limited use in oilfield fluids and production streams Silicate inhibitors have the unusual property of being effective in already-corroded systems where most other corrosion inhibitors lose their effectiveness. Other precipitating inhibitors include calcium salts (calcium carbonate and calcium phosphate) and zinc salts (zinc hydroxide and zinc phosphate). Calcium compounds are widely used in potable water systems to maintain the pH of water at a high level (typically around pH 8-9) and with a slight oversaturation of calcium in the water so that any exposed surfaces will be covered with thin carbonate scales. This has been standard potable water treatment practice since the 1920s.

Passivating inhibitors that oxidize metal surfaces are commonly used in steam and water systems, but they are seldom used before effective hydrocarbon-water: separation has occurred. They also tend to be ineffective in high-chloride waters like the majority of produced water systems.

Chromates are the most effective passivating inhibitors, but environmental concerns have limited their use especially for any application where water discharge is possible. Alternatives to chromates are not as effective although research continues on their development. At present, most non-chromate-oxidizing inhibitors are based on nitrites, which are considered to have fewer environmental problems than either chromates or phosphates. Bacterial decomposition of nitrites limits their use in open recirculating water systems. Molybdates and Tungstates are also available. None of these oxidizers work in the presence of H_2S.

Indirect passivators are alkaline chemicals that increase pH by reacting with hydrogen ions and removing them from the surface so that oxygen can adsorb onto the surface and react with the metal. Unlike the direct passivators, these corrosion inhibitors will not work in the absence of dissolved oxygen. Inorganic direct passivators include NaOH, Na_3PO_4, Na_2HPO_4, Na_2SiO_3, and Na_2B_4O. (borax). Organic indirect passivators include sodium benzoate and sodium cinnamate. These organic passivators have the advantage of not causing pitting corrosion if the chloride ion becomes too concentrated, but the general weight-loss corrosion rate does increase.

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Part 2: Offshore Structures: Strength, Stability and Corrosion Control Strategies

Section a	**Structure, Strength and Stability of Offshore Platforms**
Section b	**Structure, Strength and Stability of Offshore Wind Turbines**
Section c	**Corrosion Prevention Strategies**

International Institute of Marine Surveying

Professional Qualification

in Marine Corrosion

Presented by **Mike Lewus**

Module 4
(section a)

Structure, Strength and Stability of Offshore Platforms

Module 4 (section a)

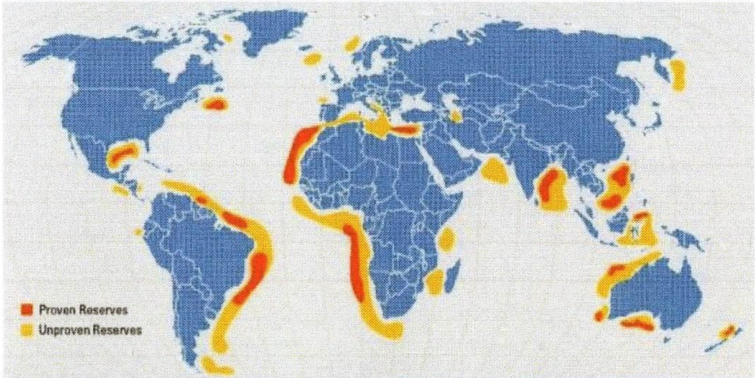
Summary

- World Production
  - Oil reserves and recent trends
  - UK and North Sea
  - Processing aspects
- Oil and Gas Platforms
  - Offshore platform types - general
  - Fixed platforms
  - Compliant platforms
  - Exploration systems and FPSOs
  - Wind and wave loads
- Other Platform Equipment
  - Drill, wellhead and casings
  - Blowout preventer

Module 4 (section a)

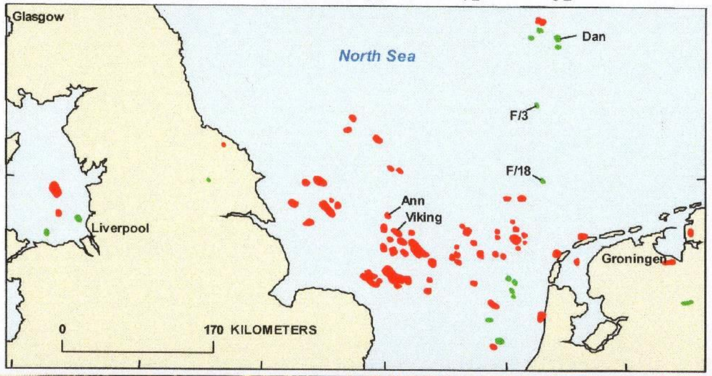
Global Oil and Gas Fields

- There are many large offshore oil fields, the 3 largest producing oil fields are in the Persian gulf - Venezuela has the largest estimated reserves



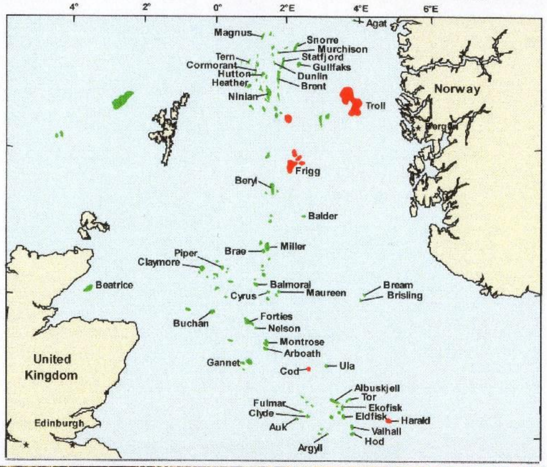
Module 4 (section a) — North Sea Oil and Gas Fields

- Oil and gas fields in the North Sea – Norway biggest producer



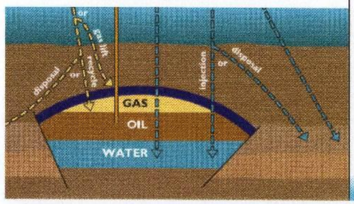
Module 4 (section a) — North Sea Oil and Gas Fields

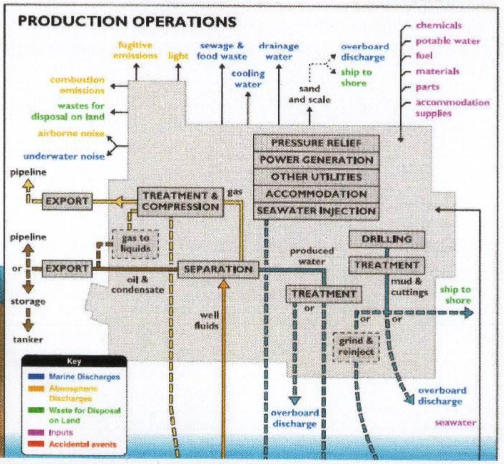
- The North Sea is the largest offshore field in Europe and is operated by Norway, Netherlands, United Kingdom, Germany and Denmark
- Norway is the largest producer and has the largest oil reserves in Western Europe
- The proven oil reserve of Norway is 5.3 billion barrels (Oil and Gas Journal, 2014)
- The low temperatures of the N. Sea region set challenges for platform designers



Module 4 (section a) — Oil and Gas Platform Production Operations

- Key processes on a platform:
  - Separation of multiphase well fluids
  - Gas processing
  - Oil and condensate processing
  - Water treatment and discharge
  - Drilling treatment & discharge

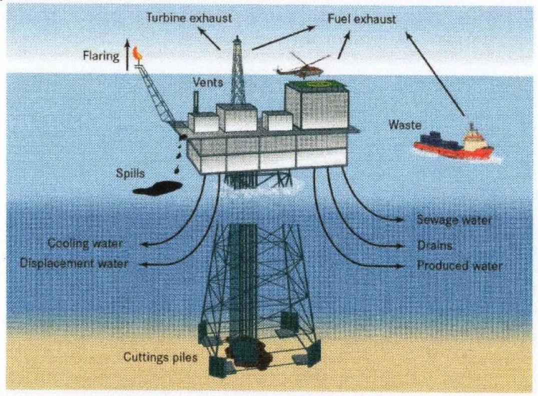




Module 4 (section a) — Oil and Gas Platform Discharges

OSPAR (Convention for the Protection of the Marine Environment of the North-East Atlantic)

Chemical inputs to the marine environment from the offshore oil and gas industry vary depending on the activity being carried out. Discharges of hydrocarbons from offshore oil and gas installations are primarily from produced water, containing both natural substances & added chemicals. OSPAR aimed for discharges close to zero by 2020



Oil and Gas Platform Types

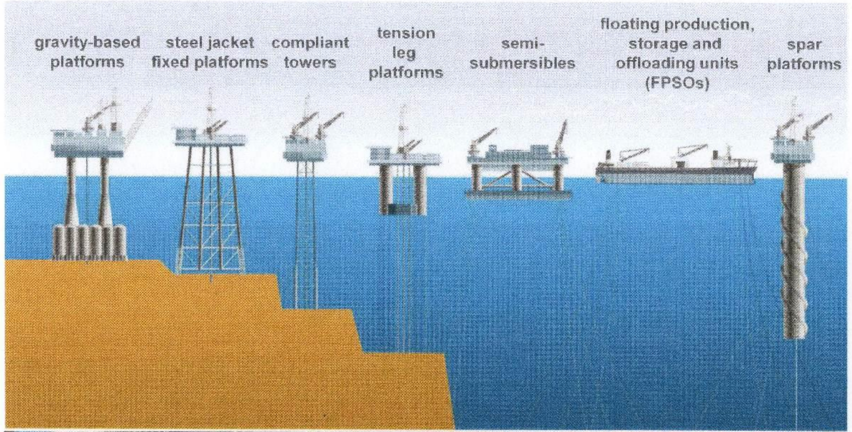
Module 4 (section a)

- Offshore Platforms can be categorized in 3 Types
  - Bottom supported structures (≤ 450m)
    - Gravity-based platforms
    - Steel jacket fixed platforms
  - Compliant structures (450 – 900m)
    - Guyed towers
    - Articulated towers
    - Tension leg platforms (up to 2100)
  - Floating production systems (450 – 1800m)
    - Semi submersibles
    - Floating production units (FPSOs)
    - Spar platforms
  - New generation platforms (deep – ultradeep >3000m)
    - Buoyant leg/tower structures

Oil and Gas Platform Types

Module 4 (section a)

- Types of oil and gas production platforms



Oil and Gas Platforms: Gravity-Based

Module 4 (section a)

- Gravity-based platforms
  - Concrete has been widely used to build some offshore structures. These structures are called gravity platforms or gravity-based structures (GBS). A gravity platform relies on the weight of the structure to resist encountered loads instead of pilings

Troll A Platform, Shell, N. Sea, Constructed by KCC

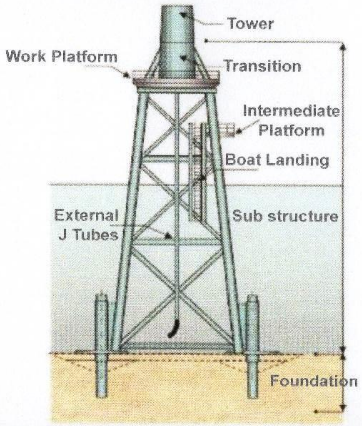
Oil and Gas Platforms: Gravity-Based

Module 4 (section a)

- Gravity-based platforms
  - Advantages
    - Relies on weight of the structure to resist the encountered loads instead of pilings - an advantage where seabed conditions make it difficult to drive in piling
    - Structures cover a large area of seabed making failure due to overturning moments unlikely
    - Can support large topside loads during towing, minimizing hook up work during installation
  - Disadvantages
    - Unsuitable for sites with poor soil conditions
    - Long construction periods delaying production
    - Natural frequencies falling within an undesirable range

Oil and Gas Platforms: Steel Jacket

- Steel Jacket Platform



Oil and Gas Platforms: Compliant Types

- Compliant Platforms
  - Designed to overcome the short comings of gravity platforms
  - A structural form designed to attract fewer forces and remain flexible to withstand cyclic forces
  - A compliant tower is designed to flex with the forces exerted by waves, wind and current
  - Include structures that extend to the ocean floor and are anchored directly to the seabed by piles or guidelines
  - Structural action of compliant platforms is different from that of fixed ones because they resist lateral loads not by their weight, but by their relative movement
    - Structure moves in line with the wave forces
    - They are position-restrained by cables/tethers/guy wires

Oil and Gas Platforms: Compliant Types

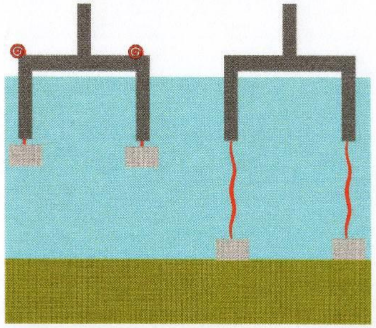
- Compliant Platforms
  - Petronius is a deepwater compliant tower oil platform operated by Chevron Corp. and Marathon oil in the Gulf of Mexico, 210 km southeast of New Orleans, United States
  - The seabed is 535 m (1,754 ft) below the platform

Oil and Gas Platforms: Compliant Types

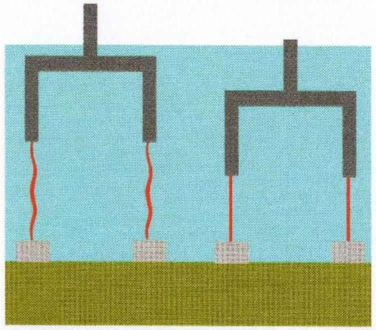
- Tension Leg Platforms (TLP)
  - Is a vertically moored compliant platform
  - Taut mooring lines referred to as tendons or tethers, vertically moor the floating platform which is designed to have excess buoyancy
  - The structure is vertically restrained while being compliant in the horizontal direction, permitting surge, sway and yaw motions
  - Substantial pretension is required to prevent the tendons falling slack even in the deepest trough, this is achieved by adjusting the free floating draft
  - Typical natural periods of the TLP are kept away from the range of wave excitation periods and are achieved by proper design
  - Give favourable response under lateral earthquake loads

Oil and Gas Platforms: Compliant Types

LHS: A tension-leg platform (gray) under tow with seabed anchors (light gray) held up by cables (red) on LHS
RHS: platform with seabed anchors lowered and cables lightly tensioned

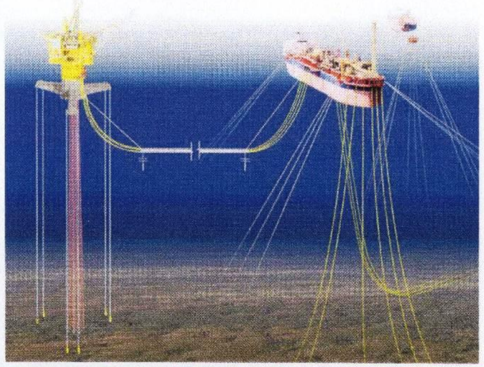


LHS: Tension leg platform (gray) free floating
RHS: structure pulled by the tensioned cables (red) down towards the seabed anchors (light-gray) NB very simplified, omitting details of temporary ballast transfers



Oil and Gas Platforms: Compliant Types

- Tension Leg Platforms
  - TLP designs now include E-TLP, Moses-TLP and SeaStar TLPs

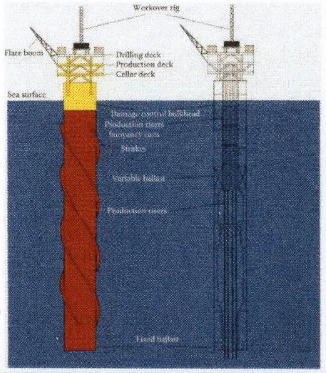


Oil and Gas Platforms: Spar Type

- Spar Platforms
  - Spar platforms consist of a deep-draft floating caisson, which is a hollow cylinder structure similar to a very large buoy
  - The major components of a spar platform are hull, moorings, topsides and risers
  - Distinguishing feature is a deep draft hull which provides very favourable motion characteristics
  - Salient features
    - Water-depth capability ranges up to 3000m
    - Full drilling and production capabilities
    - Direct vertical access production risers
    - Surface blowout preventer
    - Traditional construction (steel or concrete hull)
    - Relocatable over a wide range of water depths

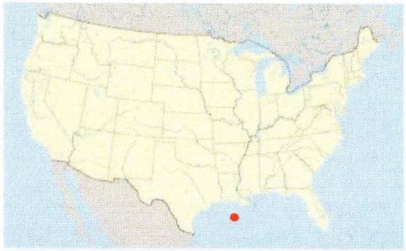
Oil and Gas Platforms: Spar Type

- Spar Platforms
  - World's deepest production platform is Perdido, a truss spar in the GoM, mean water depth of 2,438m – cost $3B



Oil and Gas Platforms: Spar Type

- Spar Platforms
  - Mad Dog spar, located in the Gulf of Mexico, taken in July 2012
  - Water depth ~2000m

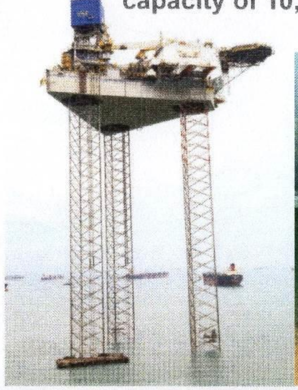


Oil and Gas Platforms: Exploration Types

- Platforms for Exploration
  - Three common types: Jack-Up platforms, semi-submersible platforms and drill ships
    - A jack-up platform typically consists of 3 legs with a deck supporting a helideck, drilling mast etc. The floating deck is used to tow the jack-up platform with the legs positioned above deck
    - A semi-submersible system has pontoons to provide buoyancy. These are positioned below the water surface to reduce the effect of wave action
    - A drillship is a vessel designed for use in exploratory offshore drilling of new oil and gas wells or, for scientific drilling purposes, the forerunner of FPSOs

Oil and Gas Platforms: Exploration Types

- Jack-Up Platform
  - world's largest jack-up rig with a maximum drilling depth capacity of 10,000 metres (Singapore/ Sembcorp Marine)



Oil and Gas Platforms: Exploration Types

- Semi-Submersible Platforms
  - Obtain their buoyancy from ballasted, watertight pontoons located below the ocean surface. Structural columns connect the pontoons and operating deck

2006

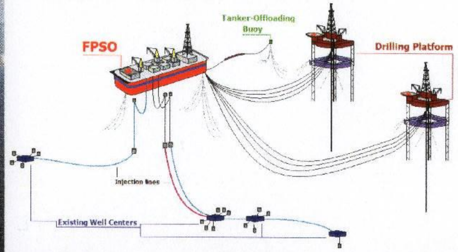
Module 4 (section a) — Oil and Gas Platforms: Exploration Types

- Drill Ships
  - a maritime vessel that has been fitted with drilling apparatus. In order to drill, a marine riser is lowered to the seabed with a Blow Out Preventer (BOP) at the bottom (see later slide)
  - Ability to drill up to 5000m; newer vessels up to 7000m

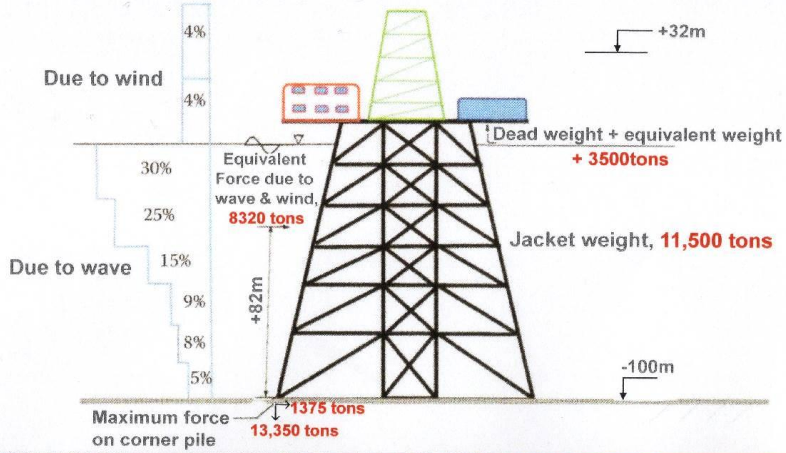
The mobile offshore drilling unit Q4000 holds position directly over the damaged Deepwater Horizon blowout preventer

Module 4 (section a) — Oil and Gas Platforms: Floating Production Units

- Floating production, storage, and offloading system (FPSOs)
  - large ships equipped with processing facilities and moored to a location for a long period
  - designed to take all the oil or gas produced from nearby platforms, process and store it

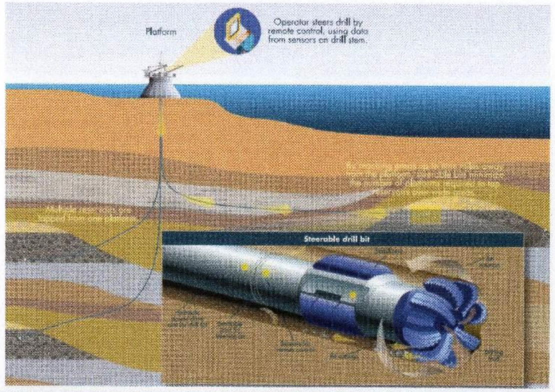


Module 4 (section a) — Offshore Platform: Wind and Wave Loads

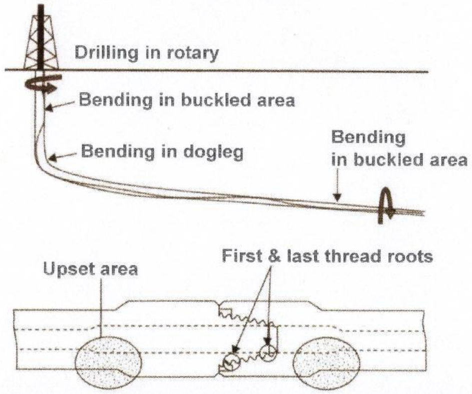


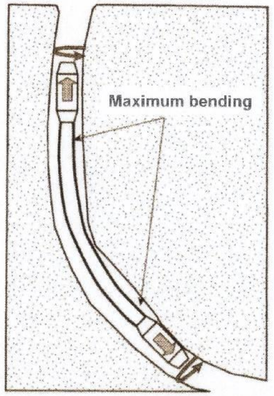
Module 4 (section a) — Oil and Gas Platforms: Other Key Equipment

- Drills and drill pipe: Directional and horizontal drilling is used to tap multiple reservoirs from one platform



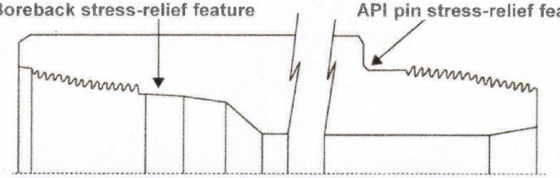
- Drills: Critical drill pipe fatigue areas



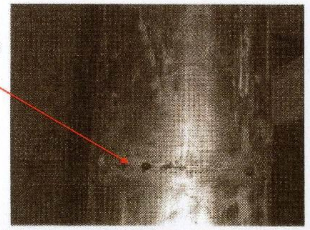


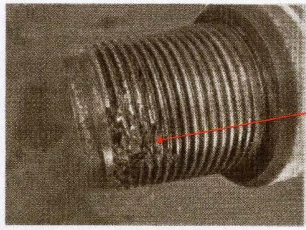
- Drills: Wear and Fatigue

Stress reduction by elimination of sharp features



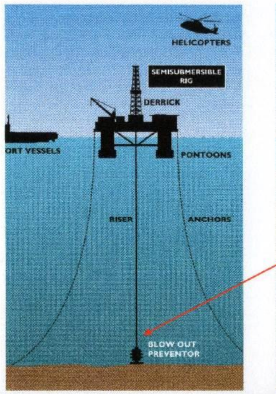
Drill pipe corrosion fatigue crack

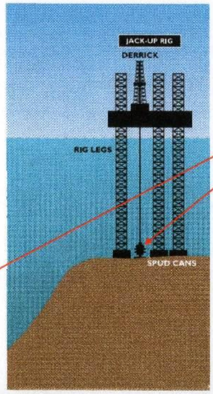


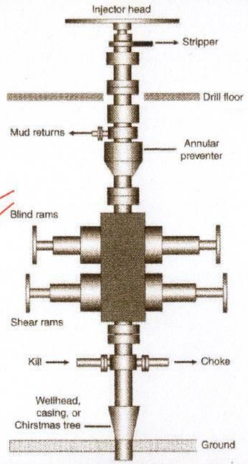


Wear damage on threads of drill pipe

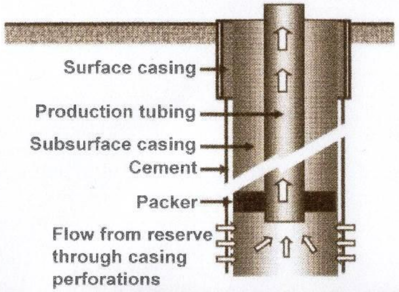
- Blowout Preventer (BOP)
  - Usually located at wellhead





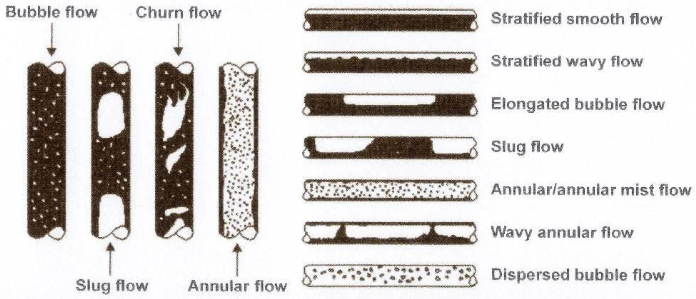


- Blowout Preventer (BOP)
  - Large devices used to mechanically seal, control and monitor oil and gas wells and avoid blowouts – sudden releases of downhole fluids caused by sudden changes in downhole formation pressure



Oil and Gas Platforms: Other Key Equipment

- Oilfield tubing, pipeline and process equipment
  - A variety of fluid flow regimes can occur in oilfield tubing, piping and process equipment and these determine the nature of erosion-corrosion, under deposit corrosion and other forms are likely to occur



International Institute of Marine Surveying

Professional Qualification

in Marine Corrosion

Presented by **Mike Lewus**

Module 4

(section b)

Structure, Strength and Stability of Offshore Wind Turbines

Module 4 (section b)

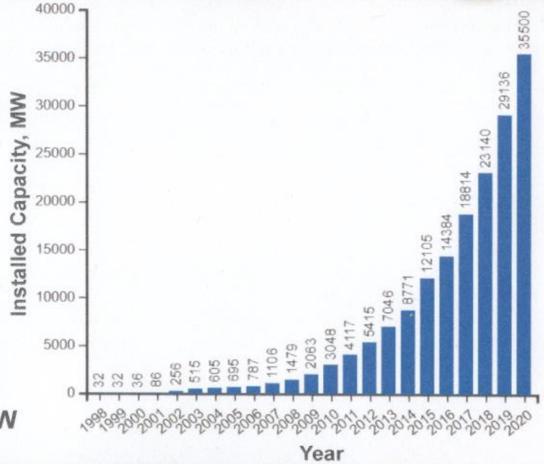
Summary

- **World Production**
  - Trends in Offshore Wind Generation Capacity
  - Trends in Wind Turbine Size
  - Global Potential for Wind Power
- **Wind Turbine Types**
  - Anatomy of a wind turbine
  - Foundation types
  - Support vessels
  - Floating wind turbines
    - Spar
    - Tension Leg
    - Semi submersible

Module 4 (section b)

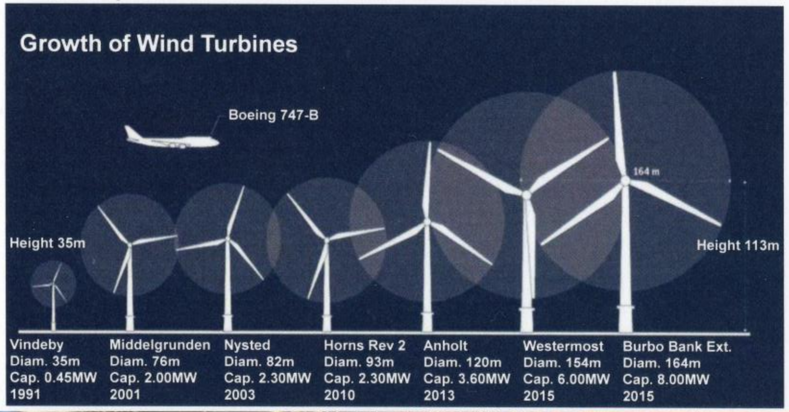
Global Offshore WTG: Installed Capacity

- Global cumulative offshore capacity - Mega Watts
- Europe is the world leader in offshore wind power
- First offshore wind farm (Vindeby) installed in Denmark in 1991
- UK total capacity 24.2GW (Jan. 2021) c.f. China 2380GW
  Germany 55.6GW
  USA 122GW



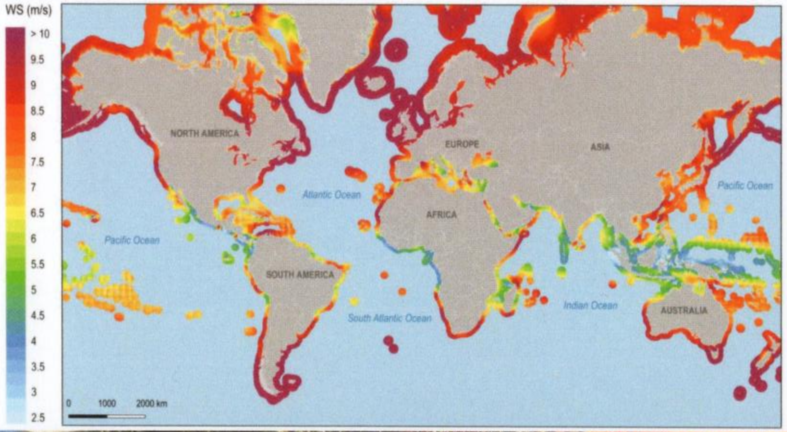
European Offshore WTG: Growth in Capacity

- The average capacity of newly installed offshore wind turbines in Europe has increased from 3 MW in 2010 to > 8 MW in 2017

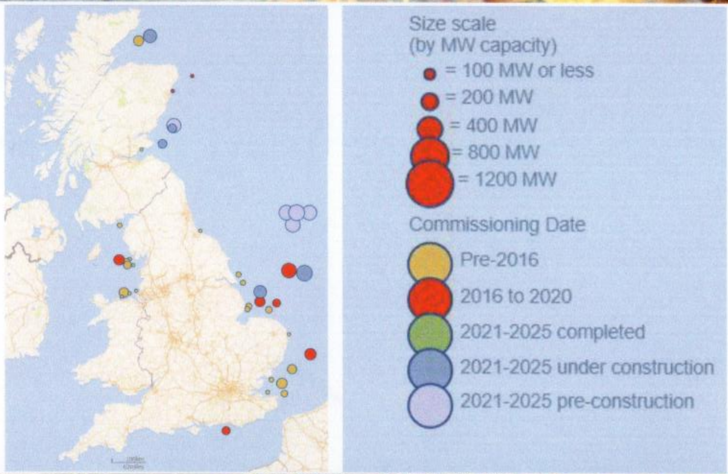


Potential of Offshore Energy

- Map of Global Offshore Wind Speeds

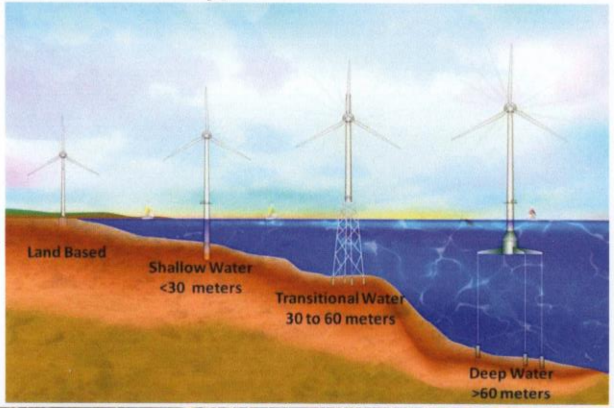


Offshore Wind Farms in UK Waters



Offshore Wind Turbine Generator Types

- Definition of land-based, shallow, transitional and deep water wind turbine types

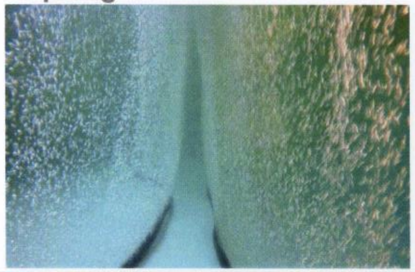


Anatomy of a Wind Turbine:

- Considering a wind turbine with a monopile foundation, the base structure i.e. monopile is essentially a hollow, cylindrical steel tube (LHS) which is driven into the seabed using an impact hammer (RHS)

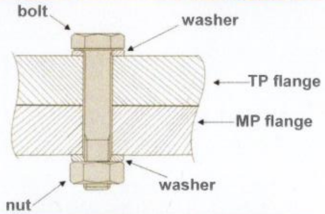
Anatomy of a Wind Turbine

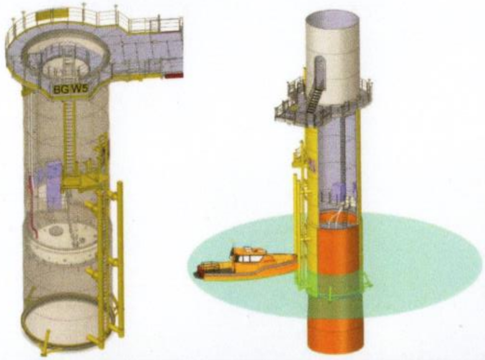
- A bubble curtain is a screen of bubbles which surrounds a working area. Underwater bubbles inhibit sound transmission through water due to density mismatch and concomitant reflection and absorption of sound waves. Such a curtain helps protect marine life from piling noise



Anatomy of a Wind Turbine

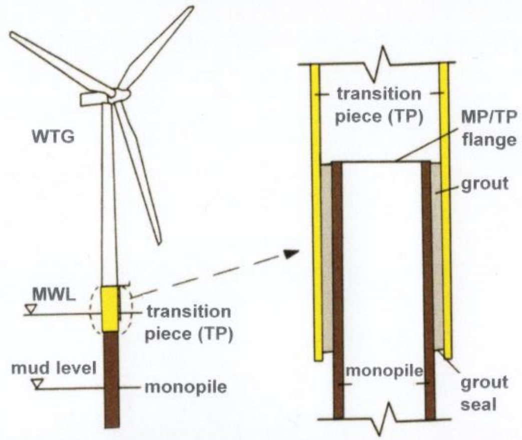
- A transition piece is bolted to the monopile and acts as an interlink for the WTG





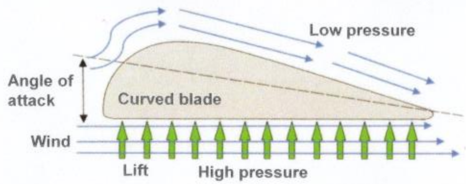
Anatomy of a Wind Turbine

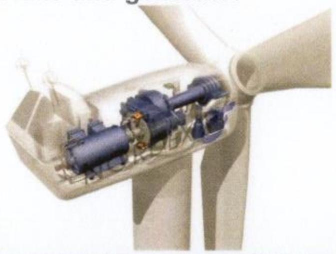
- Grouting, a mortar is used for filling spaces, is used offshore to create a structural connection between a topside and a foundation that has been driven into the seabed. An ultra high strength grout is used between the TP sleeve and MP



Anatomy of a Wind Turbine

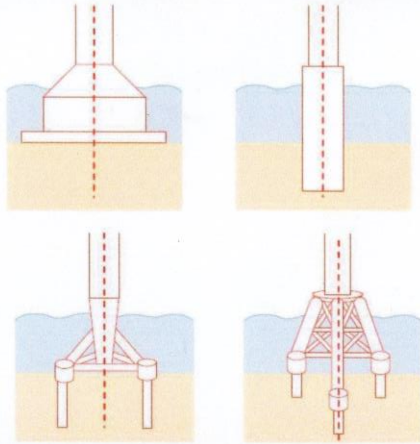
- The blades of a wind turbine operate under the same principle as an aircraft wing
- The nacelle contains the shaft, gearbox, brake and generator





Anatomy of a Wind Turbine

- Two types of wind turbine foundation
  - Fixed
    - Monopile
    - Gravity
    - Tripod
    - Jacket
  - Floating
    - Spar-buoy
    - Semi-submersible platform
    - Tension leg platform



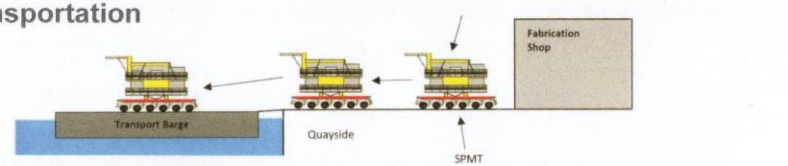
Wind Farm Infrastructure

- Map of Wind Farm Layout – Cable laying vessels travel towards the OHVS while laying cable on the seabed

OHVS at Alpha Ventus, Germany

Wind Farm Infrastructure

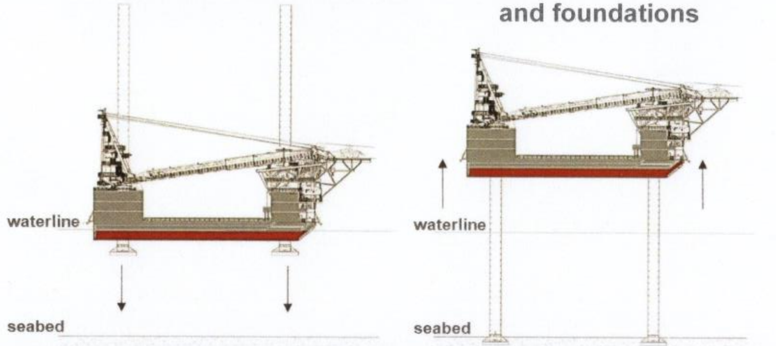
- Offshore high voltage substation (OHVS) – Fabrication & Transportation



Fabrication and assembly

Transportation by barge

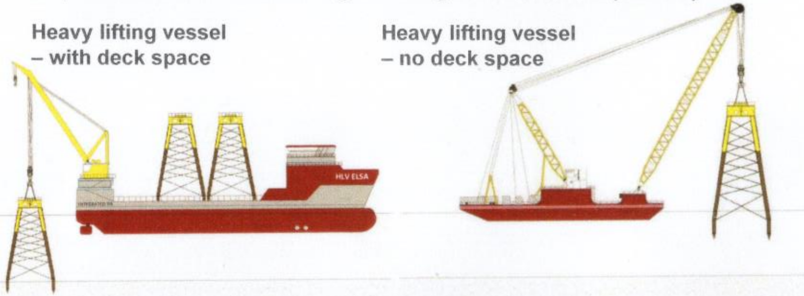
- **Self-elevating vessels, or jack-up installation vessels**
  - used within the offshore wind turbine industry to transport, lift and install offshore wind turbines, transition pieces and foundations



- **Jackup barge being used to dismantle a ship**
  - specialized barge, similar to an oil and gas platform, but are used as a base for servicing other structures such as offshore wind turbines, bridges, and drilling platforms etc

https://en.wikipedia.org/wiki/Jackup_rig

- **Heavy lift crane vessels**
  - floating (non elevating) vessels equipped with high capacity lift cranes, used within the offshore wind industry to transport, lift and install offshore foundations, transition pieces and offshore high voltage substation (OHVS)



- **Heavy lift crane vessels**
  - During operation these vessels maintain their position using 'dynamic positioning' (DP) a computerized system that automatically controls the vessels position & heading

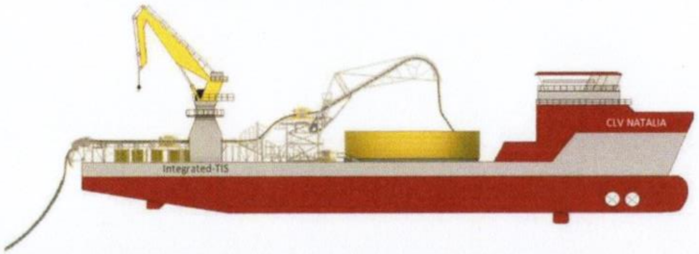
Stanislav Yudin, Port of Limassol

Matador 3 IMO 9272137 Port of Rotterdam

Module 4
(section b)

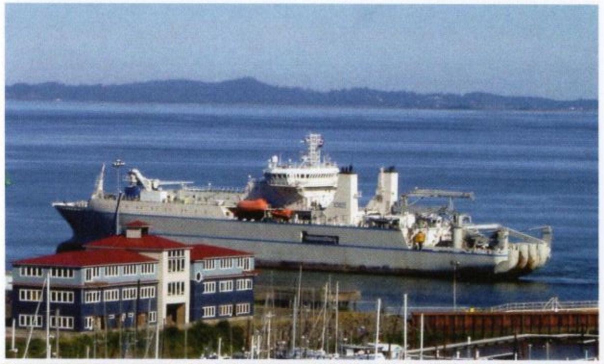
Wind Turbine Support Vessels

- **Cable laying vessels**
  - **Cable laying vessels are used within the offshore wind industry to transport and install large volumes of offshore submarine power cables. Cable load is typicall many km which are used to connect the wind turbines to the power grid**



Module 4
(section b)
Wind Turbine Support Vessels

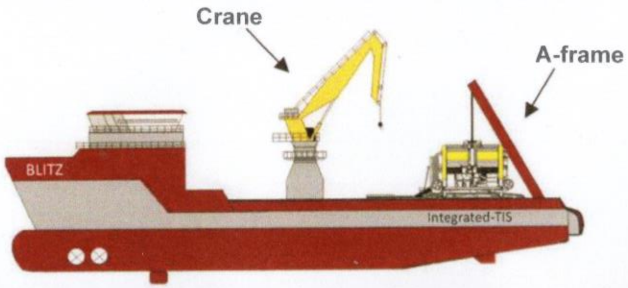
- **Cable laying vessels typically house support crane, carousel (turntable) and tensioner systems designed to lay cable from the vessel onto the seabed**



https://en.wikipedia.org/wiki/Cable_layer#
/media/File:Cable_layer_ship.jpg

Module 4
(section b)
Wind Turbine Support Vessels

- **DP2 construction support vessel**
  - **Are used within the offshore wind industry to support the preparation works, cable laying operations and during commissioning of turbines**



Module 4
(section b)
Wind Turbine Support Vessels

- **DP2 construction support vessel**
  - **Also used to perform surveys, install scour protection mats, prep. of foundations and offshore high voltage substation (OHVS) for cable pulling systems and commissioning temporary generators, hoisting systems and other equipment**

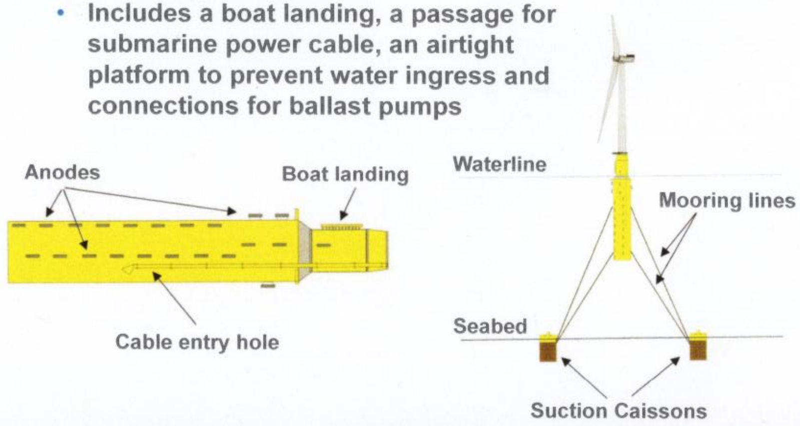
https://www.mauric.ecagroup.com
/construction-support-vessel

Module 4 (section b) Floating Wind Turbines

- Floating Wind Turbine Foundation Types
  - Spar-Buoy foundation
    - A cylinder with low water plane area, ballasted to keep the centre of gravity below the centre of buoyancy (see following slides)
  - Semi-submersible platform foundation
    - Consist of large columns linked by connecting bracings and submerged pontoons; the columns provide the required hydrostatic stability and pontoons, the additional buoyancy
  - Tension Leg platform foundation
    - A buoyant platform held in place by a mooring system – similar to conventional fixed platforms except that the platform is maintained on location by use of moorings held in tension by hull buoyancy

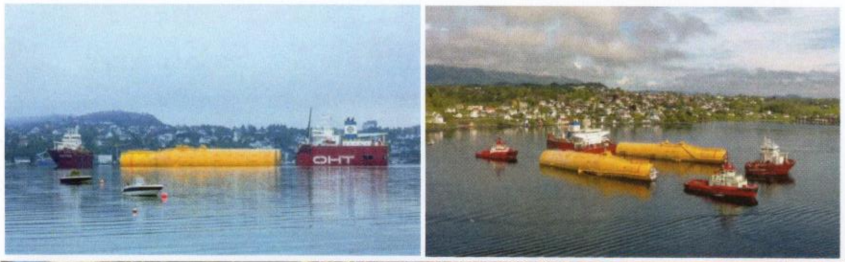
Module 4 (section b) Floating Wind Turbines: Spar-Buoy WTG

- Spar Buoy Foundation
  - Includes a boat landing, a passage for submarine power cable, an airtight platform to prevent water ingress and connections for ballast pumps



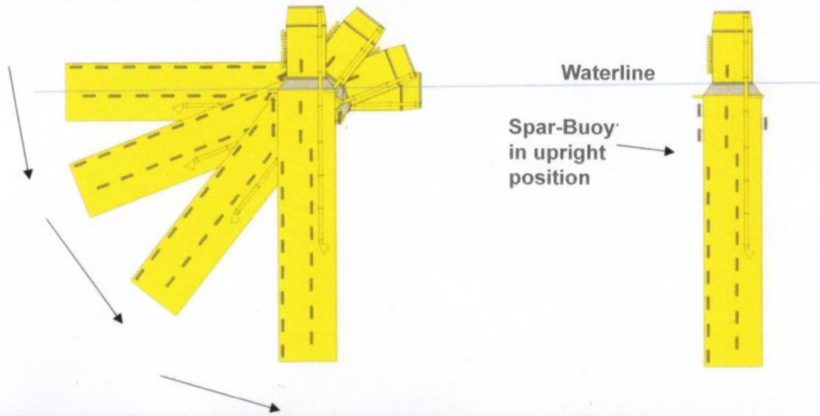
Module 4 (section b) Floating Wind Turbines: Spar-Buoy WTG

- Transportation via Semi-submersible Vessel



Module 4 (section b) Floating Wind Turbines: Spar-Buoy WTG

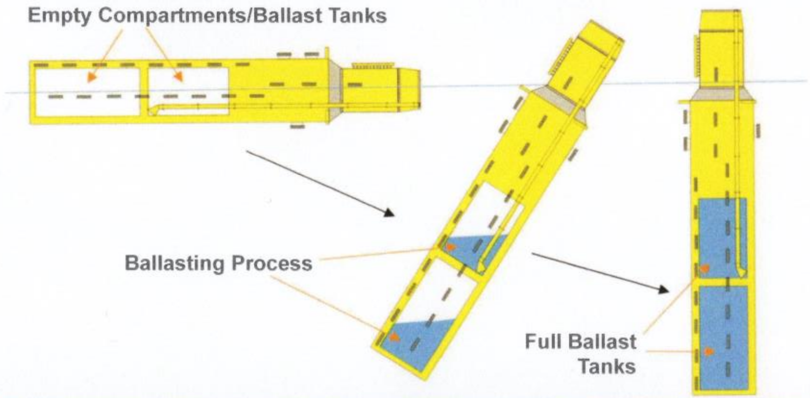
- Upending Process - Ballast Tank Filling



Module 4 (section b)

Floating Wind Turbines: Spar-Buoy WTG

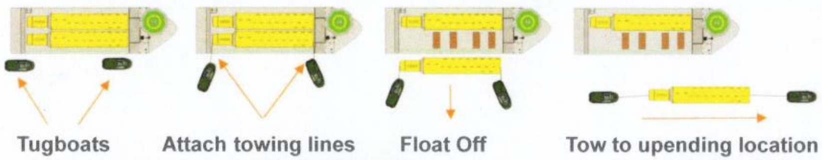
- Upending Process - Ballast Tank Filling



Module 4 (section b)

Floating Wind Turbines: Spar-Buoy WTG

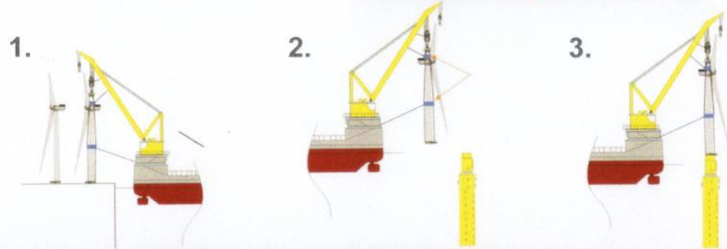
- Transportation via semi-submersible vessel



Module 4 (section b)

Floating Wind Turbines: Spar-Buoy WTG

- Final Assembly
  - Pick-up at quayside
  - Transport to substructure
  - Land wind turbine on substructure



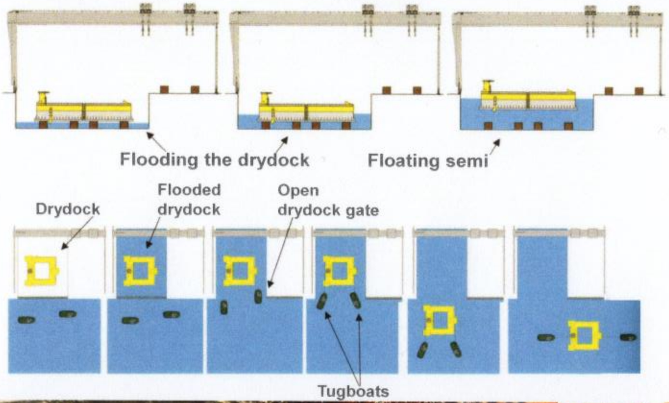
Module 4 (section b)

Floating Wind Turbines: Semi-Submersible

- Semi Submersible Wind Turbine
  - Step 1: foundation is assembled inside a drydock

Module 4 (section b) Floating Wind Turbines: Semi-Submersible

- Semi Submersible Wind Turbine
  - Step 2: Drydock flooded, platform floated and towed

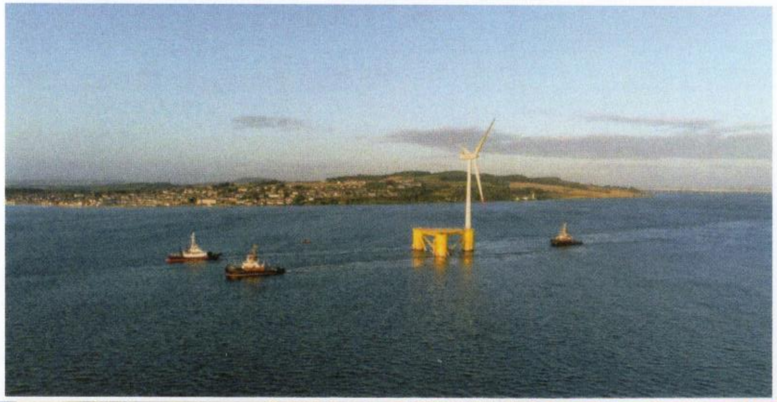


Module 4 (section b) Floating Wind Turbines: Semi-Submersible

- Semi Submersible Wind Turbine
  - Step 3: Assemly of WTG

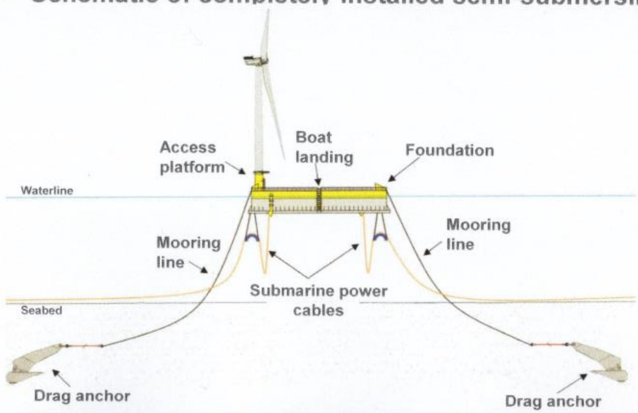
Module 4 (section b) Floating Wind Turbines: Semi-Submersible

- Semi Submersible Wind Turbine
  - Step 4: Towing to location



Module 4 (section b) Floating Wind Turbines: Semi-Submersible

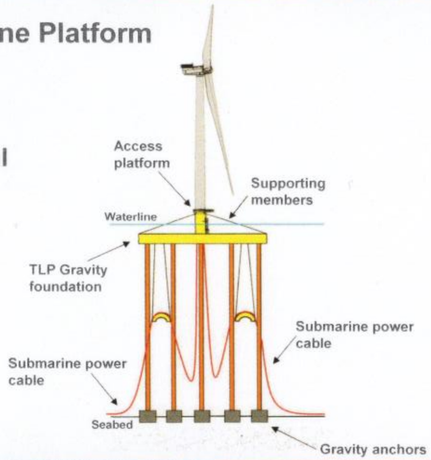
- Semi Submersible Wind Turbine
  - Schematic of completely installed semi-submersible



Module 4 (section b)

Floating Wind Turbines: Tension-Leg Platform (TLP)

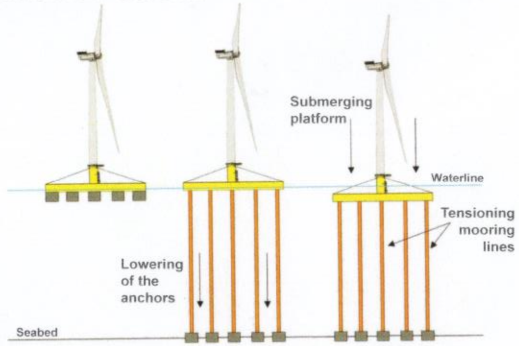
- Tension Leg Wind Turbine Platform
  - A buoyant platform held in position by a mooring system
  - Similar to conventional platforms except that the platform is maintained on location through the use of moorings held in tension by the buoyancy of the hull



Module 4 (section b)

Floating Wind Turbines: Tension-Leg Platform (TLP)

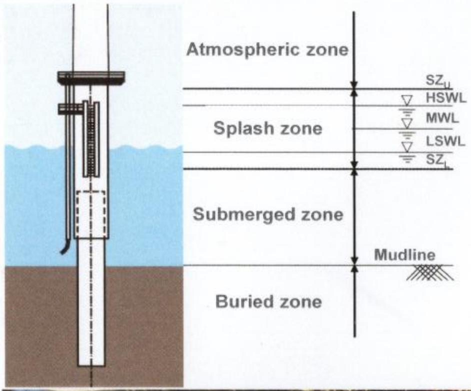
- Tension Leg Wind Turbine Platform
  - Platform floated in position - platform & anchors partially filled with water to maximise stability
  - Anchors fully ballasted and extended to seabed
  - Platform submerged with winches to tension wire mooring lines

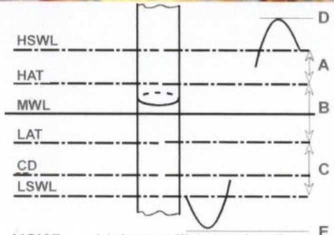


Module 4 (section b)

DNV GL: Recommended Wind Turbine Practice

- Schematic representation of levels and zones in sea water environment





HSWL	highest still water level
HAT	highest astronomical tide
MWL	mean water level
LAT	lowest astronomical tide
CD	chart datum (often = LAT)
LSWL	lowest still water level
A	positive storm surge
B	tidal range
C	negative storm surge
D	maximum crest elevation
E	minimum trough elevation

Professional Qualification
in Marine Corrosion

Presented by **Mike Lewus**

Module 4
(section c)

Corrosion Prevention Strategies

Module 4 (section c)

Summary

- Oil and Gas Platforms
  - Corrosion environment
  - Corrosion protection strategies
    - Coatings
    - Cathodic protection: Anodes and ICCP
    - Inhibitors
    - Microbial induced corrosion (MIC)
  - Inspection and monitoring
    - Mass-loss coupons
    - Electrical probes
      - ER probe
      - LPR probe
      - Galvanic probe
      - Acoustic probe

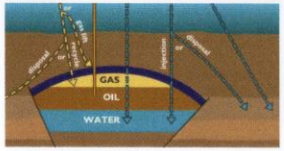
Module 4 (section c)

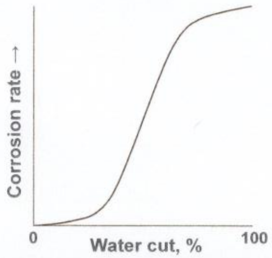
Oil and Gas Platform: Corrosion Environment

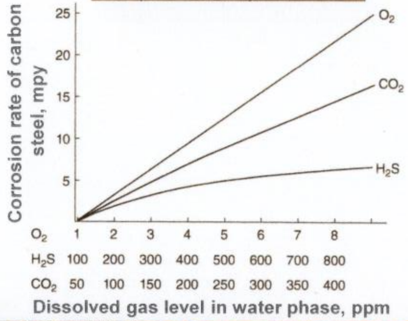
- Oilfield Corrosion - General
  - A very limited amount of oilfield corrosion is associated with high temperature, atmosphere exposure common in flares
  - The majority of oilfield corrosion requires liquid water. Downhole formation water that comes to the surface with oil and gas production often includes:
    - O_2, this is normally a problem only with surface equipment, because oxygen is unlikely to occur naturally in downhole formations
    - Sulphur containing species
    - Naturally occurring radioactive materials (NORM)
    - CO_2
    - H_2S

Module 4 (section c) Oil and Gas Platform: Corrosion Environment

- Oil drill pipe environment
  - Water has limited solubility in hydrocarbons
  - Gas composition has a significant impact on corrosion

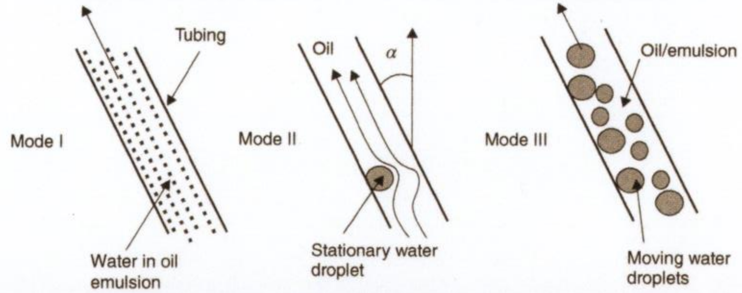






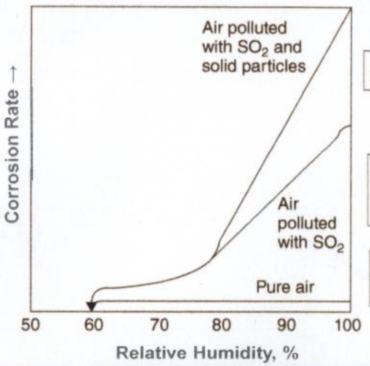
Module 4 (section c) Oil and Gas Platform: Corrosion Environment

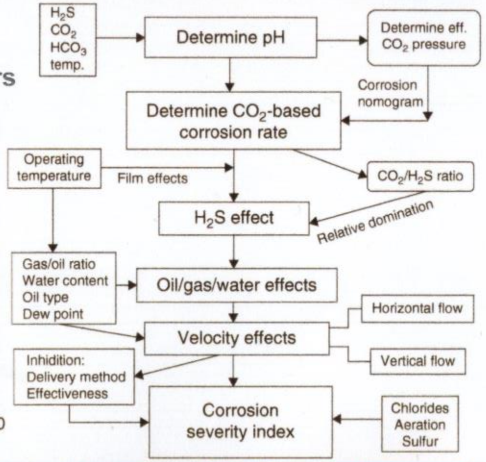
- Water Pipeline Wetting Process
  - As the water cut increases, the amount of metal surface in contact with water increases until the emulsion reverses and the liwuid becomes continuous water containing entrained hydrocarbon droplets



Module 4 (section c) Oil and Gas Platform: Corrosion Environment

- External Environment
  - Relative humidity
  - Other important factors





Module 4 (section c) Oil and Gas Platform: Corrosion & Dissolved Gas

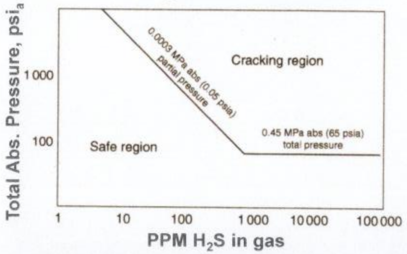
- Significance of dissolved gases: O_2, CO_2, H_2S
  - Carbon steel is the most common metal used in, corrodes at unacceptable rates in many aqueous environments
    - Many reports ascribe corrosion damage to the presence of chlorides, but corrosion rate reduces in strong chloride containing brine - max. at 3wt. % NaCl
    - NB most of the corrosion in any location is due to the presence of dissolved oxygen or some other chemically reducible species (oxidizer) i.e. CO_2
  - Oil and gas that contain sulphur are termed ‘sour gas’ or ‘sour crude’ and the most common form of sulphur is Hydrogen Sulphide (H_2S) gas
    - H_2S is more soluble in crude oil than in water and it’s presence is associated with sulphide stress cracking and MIC

Module 4 (section c)

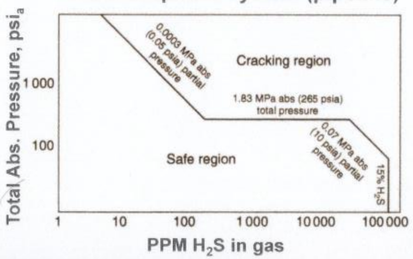
Oil and Gas Platform: H_2S Cracking

- Hydrogen Sulphide (H_2S)
  - Problems with various types of cracking led to the development of NACE MR0175/ISO 15156
  - Ultimately led to general principles for the selection of cracking resistant materials, CRAs and other alloys

Sulphide stress cracking in sour gas environment



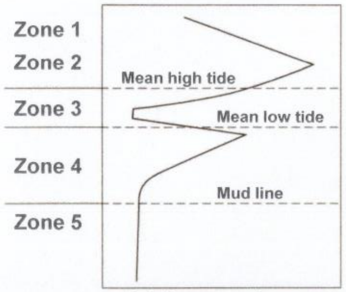
Sulphide stress cracking in sour multiphase system (pipeline)



Module 4 (section c)

Oil and Gas Platform: Corrosion Environment

- Corrosion rates of piling change in seawater at various elevations
  - Highest corrosion rates in splash zone where metal is frequently covered with air-saturated water



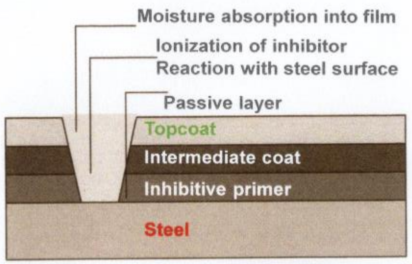
O&G Piling in Platform in Gulf of Mexico

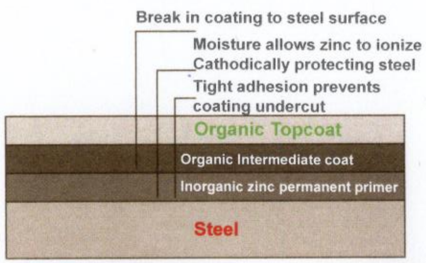
Module 4 (section c)

Oil & Gas Platform: Coating Concepts

- Coating types applied in offshore oil and gas platforms
  - Inhibitive systems
  - Cathodic protection systems

NB **Proper substrate preparation critical to good performance**





Module 4 (section c)

Oil & Gas Platform: Coatings/Organic & Metal

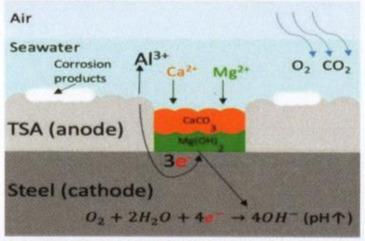
Application	Coating System	DFT, µm
Carbon Steel Operating temperature <120°C Structural steel Exteriors of equipment, vessels, piping and valves All carbon steel surfaces in noncorrosive areas (living quarters etc.) Deck areas	1 coat zinc rich epoxy 1 coat 2-component epoxy 1 coat top coat DFT(min)	60 200 75 335
Carbon Steel Operating temperature >120°C All insulated surfaces of tanks, vessels and piping Flare booms Underside of bottom deck, jacket above splash zone, crane booms, life boat station	Thermally sprayed aluminium or alloys of aluminium Sealer	200

Oil & Gas Platform: Coatings/Organic & Metal

Application	Coating System	DFT, µm
Carbon Steel		60
Walkways, escape routes and other deck areas	Nonskid epoxy screed	200
as specified	1 coat epoxy primer	75
Under epoxy-based primers	Or	335
	1 coat zinc rich epoxy	60
	1 x epoxy tie coating	25
	MDFT	85
	1 coat zinc rich epoxy	60
	1 ct. 2-component epoxy	200
	MDFT	260
Submerged carbon steel and carbon steel in	1 coat epoxy primer +	225
the splash zone	1 ct. 2-component epoxy	225
Submerged stainless steel and stainless steel	MDFT	450
in the splash zone		
Seawater filled compartments e.g. ballast tanks		

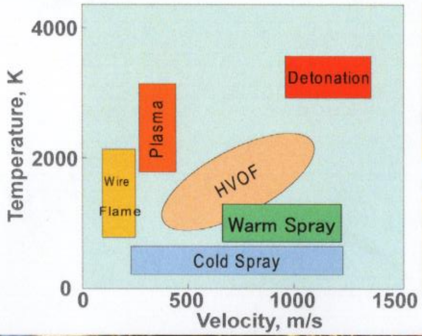
Oil & Gas Platform: Thermal Spray Aluminium

- Thermally sprayed aluminium coatings used widely for corrosion protection of offshore platform structures, vessels and oil and gas pipelines



Oil & Gas Platform: Thermal Spray Aluminium

- Thermal spraying: Coating processes in which melted (or heated) materials are sprayed onto a surface
  - The "feedstock" (coating precursor) is heated by electrical (plasma or arc) or a chemical means (combustion flame)

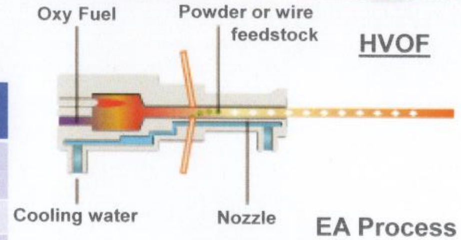


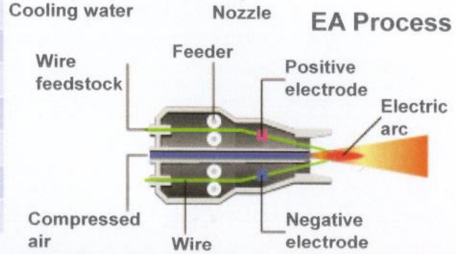
HVOF Thermally Sprayed Aluminium

Oil & Gas Platform: Thermal Spray Aluminium

- Thermal Spray Aluminium Coatings

Typical Arc Spray Process Parameters	
Particle temperature	4-6 bar
Particle velocity	Up to 5000°C
Feed stock form	100-300ms^{-1}
Max. spray rate	16kg/hr
Spray distance	15-25cm
Power input	6-80kW
Voltage	30V
Current	200A



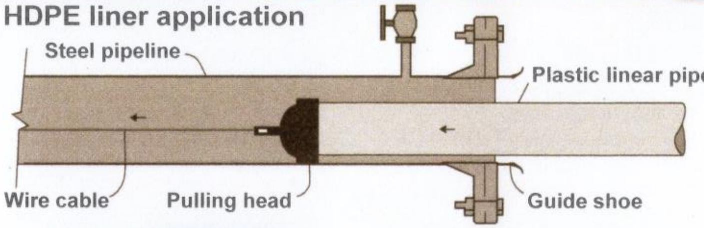


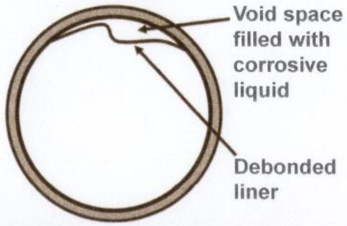
Oil and Gas Pipe Linings

- Linings, Wraps, Greases and Waxes
  - Internal linings, exterior wraps, greases and waxes find limited but nevertheless, important uses for controlled oilfield corrosion
  - Linings: relatively thick coatings (paint layers) or, more commonly, inert sheet materials adhered to or in intimate contact with the interior wall surface of a pipe or container
  - High density polyethylene (HDPE) is the most commonly used liner material
    - HDPE liners are used for water injection pipelines, injection well tubing, multiphase oil and gas gathering lines, sour crude product pipelines and oil transmission lines
  - Liners often used on tank side walls, bottoms, cargo

Oil and Gas Pipe Linings

- HDPE liner application





Oil and Gas Pipe Wraps and Tapes

- LHS: Petrolatum tape + glass-reinforced outer wrap at air-soil interface – this is a common area for corrosion because lack of soil consolidation prevents effective cathodic protection
- RHS: Conductive linear low-density polyethylene (LLDPE) membrane; angled perforations prevent sand infiltration and conductive nature enables current flow for cathodic protection

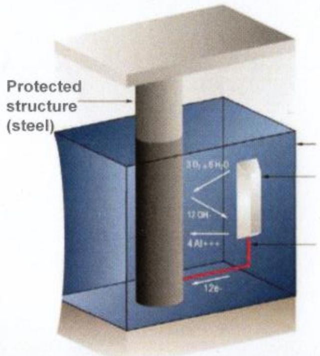
Oil and Gas Platforms: Cathodic Protection

- Three Types of Cathodic Protection System are used in Offshore Oil and Gas Platforms
  - Sacrificial: Anodes are cast from reactive metals, usually zinc or aluminium alloys as they are more electronegative than the structures requiring protection and require no external power source
  - Impressed current: Anodes are manufactured from materials that are essentially inert and powered by an external source of direct current
  - Hybrid: A mixture of sacrificial anodes and externally powered impressed current anodes

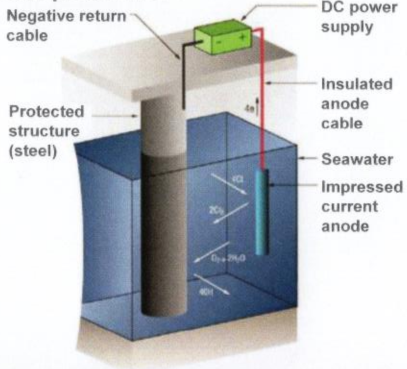
Module 4 (section c) Oil and Gas Platforms: Cathodic Protection

- Cathodic Protection Systems

Sacrificial anode cathodic protection



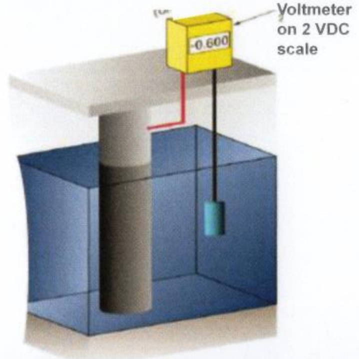
Impressed current cathodic protection



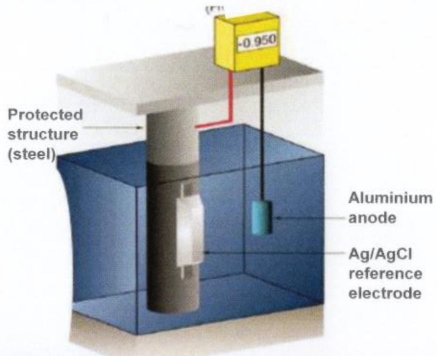
Module 4 (section c) Oil and Gas Platforms: Cathodic Protection

- Cathodic Protection Potential Measurement

Unprotected

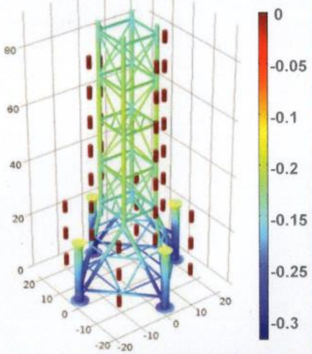


Protected



Module 4 (section c) Oil and Gas Platforms: Cathodic Protection

- In modern cathodic protection design of structures, modelling can be used to determine the variation in electrode potential with seawater depth and the effect of anode location



Module 4 (section c) Oil and Gas Platforms: Cathodic Protection

- Cathodic Protection – Retrofit Systems: Anode Pod and
  - Anode is freely suspended from locations above water either from the feed cable or a strain member
  - viable approach for shallow water structures with short life expectancy (< 5 years) & moderate-high current

Hanging Anode System at Retracted Position for a FPSO

Module 4 (section b)

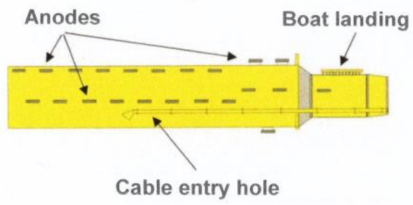
Floating Wind Turbines

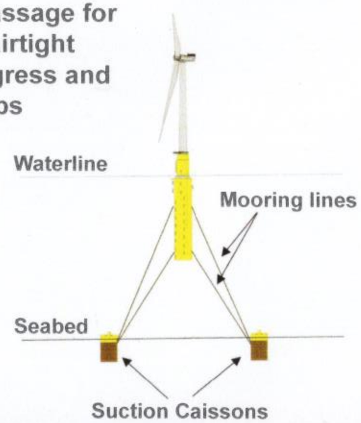
- Floating Wind Turbine Foundation Types
  - Spar-Buoy foundation
    - A cylinder with low water plane area, ballasted to keep the centre of gravity below the centre of buoyancy (see following slides)
  - Semi-submersible platform foundation
    - Consist of large columns linked by connecting bracings and submerged pontoons; the columns provide the required hydrostatic stability and pontoons, the additional buoyancy
  - Tension Leg platform foundation
    - A buoyant platform held in place by a mooring system – similar to conventional fixed platforms except that the platform is maintained on location by use of moorings held in tension by hull buoyancy

Module 4 (section b)

Floating Wind Turbines: Spar-Buoy WTG

- Spar Buoy Foundation
  - Includes a boat landing, a passage for submarine power cable, an airtight platform to prevent water ingress and connections for ballast pumps

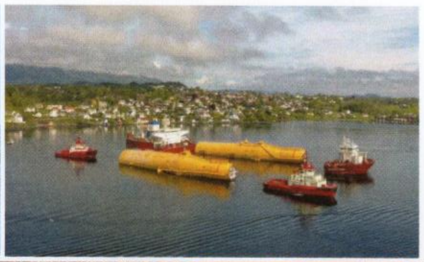




Module 4 (section b)

Floating Wind Turbines: Spar-Buoy WTG

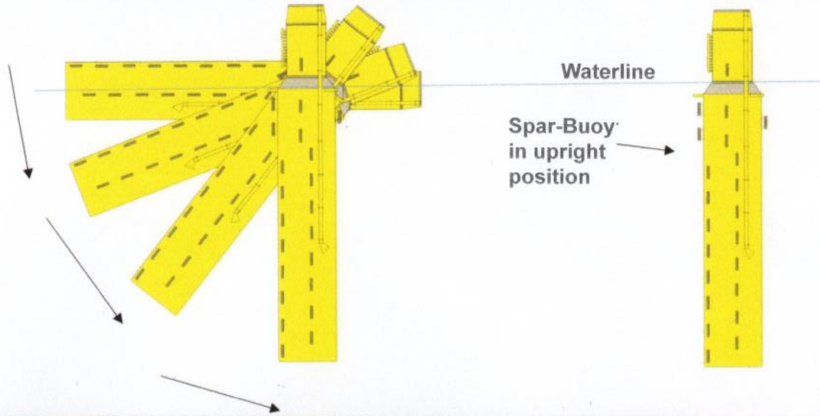
- Transportation via Semi-submersible Vessel



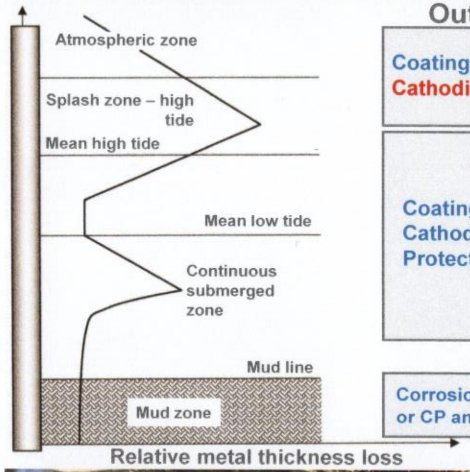
Module 4 (section b)

Floating Wind Turbines: Spar-Buoy WTG

- Upending Process - Ballast Tank Filling



WTG: Corrosion Mitigation Summary



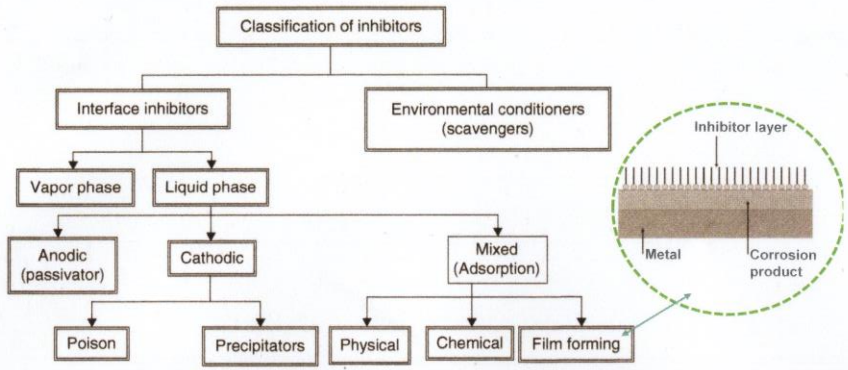
Outside	Inside
Coatings or Corrosion Resistant Alloys Cathodic protection (CP) not possible	
Coatings and Cathodic Protection (CP)	Corrosion allowance and oxygen scavengers or CP (and coating)
Corrosion allowance or CP and coating	Corrosion allowance or CP and coating

Oil and Gas Platforms: Inhibitors

- Use of corrosion inhibitors was the main method for internal corrosion control in oil and gas production in the 1980s, when production from deeper, and consequently hotter, formations led to the increasing use of CRA – corrosion resistant alloys
- Use of inhibitors can reduce corrosion rates to 5-10% c.f. no inhibitor presence
- Common types classified as:
  - Adsorption or film forming
  - Precipitation inhibitors
  - Oxidizing or anodic passivation inhibitors
  - Environmental conditioners or scavengers
  - Volatile or vapour-phase inhibitors

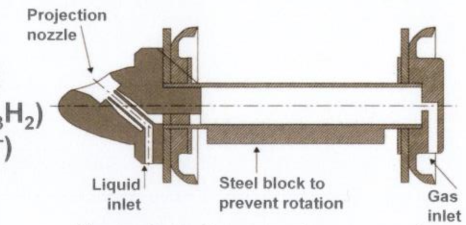
Oil and Gas Platforms: Inhibitors

- Inhibitor Categories



Oil and Gas Platforms: Inhibitors

- Most oilfield inhibitors used are film formers, including:
  - Imidazolines
  - Quaternary ammonium compounds
  - Amines ($R\text{-}NH_2$)
  - Carboxyls ($R\text{-}COOH$)
  - Thiourea (NH_2CSNH_2)
  - Phosphonates ($R\text{-}PO_3H_2$)
  - Benzonate ($C_6H_5COO^-$)
- Application methods
  - Continuous injection
  - Batch treatments (effectiveness from a week to several months)



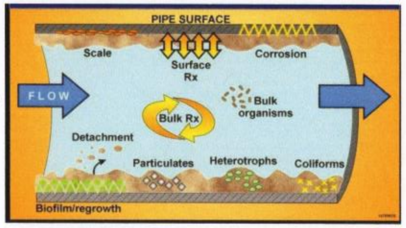
Venturi pig for spraying corrosion inhibitor onto the top of a pipeline interior to control top-of-line corrosion

Oil and Gas Platforms: MIC

- Microbially Induced Corrosion – Some experts consider it to be a growing problem in the oil and gas industry
- Observations on MIC
  - can occur in environments where corrosion is not expected e.g. downhole pumping equipment removed from any sources of oxygen or apparent corrosive agents
  - MIC corrosion rates can be very rapid
  - Laboratory liquid culture techniques do not provide accurate assessments of bacterial colonies occurring in the field
  - Mitigation and control have shifted to manipulation of the environment e.g. introduction of smooth surfaces that discourage attachment

Oil and Gas Platforms: MIC

- Microbially Induced Corrosion – Some experts consider
  - It has been suggested that many problems have been introduced by improper handling of surface waters?
  - Many types of equipment develop MIC problems, but piping systems predominate



  - The most important types of oilfield bacteria are:
    - Sulphate-reducing bacteria (SRBs
    - Iron-oxidizing bacteria (IOB)
    - Acid producing bacteria (APB)
    - Sulphur-oxidizing bacteria (SOB)
    - Slime forming bacteria

Oil and Gas Platforms: MIC

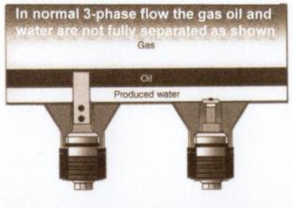
- MIC can be controlled through a number of methods
  - Regular mechanical cleaning
  - Chemical treatment of the water with biocides to control bacteria population
  - Complete drainage and dry storage
  - Use of higher alloyed stainless steels, although this may be costly
  - Filtration and ultraviolet radiation _ not likely to become an economically viable method for Oil and Gas industry?

Oil and Gas Platforms: Corrosion Monitoring

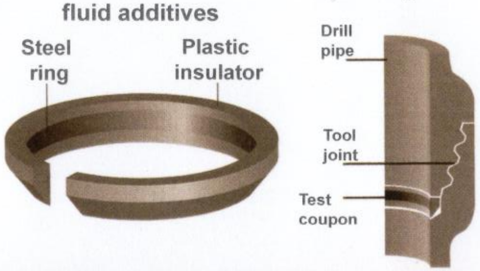
- Measurement Probes
  - Intrusion and flush mounted corrosion probes
  - Mass-loss coupons and probes
  - Electrical resistance (ER) probes
  - Linear polarization probes (LPR)
  - Galvanic monitoring (zero resistance ammetry)
  - Hydrogen probes
  - Sand monitoring
    - (ER probes), CRA tube with vacuum and acoustic sand monitor
  - Use of chemical analyses
    - PH monitoring
    - Conductivity monitoring
    - Oxygen monitoring

- Mass-Loss Corrosion Coupons
  - Use of coupons exposed to process conditions enables operators to determine if conditions and corrosion rates are changing

Intrusive and flush mounted corrosion probes inserted into a 3-phase production stream



Drill pipe corrosion ring used to monitor effectiveness of drilling fluid additives

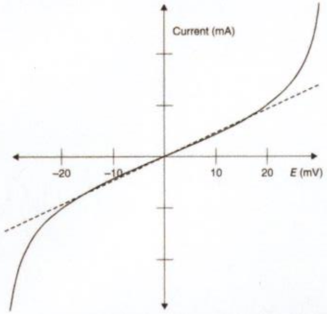


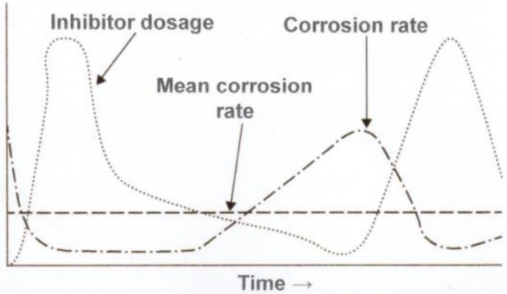
Module 4 (section c) Oil and Gas Platforms: Corrosion Monitoring

- ER and LPR probes
  - ER probes work on the principle that as corrosion or erosion of the probe occurs, the reduced metal increases resistance to electrical current – the output can be transmitted to any desired location
  - LPR probes work on the principle that the current-voltage response close to the corrosion potential is linear and the voltage/current slope is directly proportional to corrosion rate

Module 4 (section c) Oil and Gas Platforms: Corrosion Monitoring

- LPR Probe: Current Voltage Characteristics near corrosion potential - linear
  - Use of a probe can determine impact of inhibitor dose rate with time





Module 4 (section c) Oil and Gas Platforms: Corrosion Monitoring

- Galvanic corrosion monitoring probe
  - The technique involves placing electrodes of two dissimilar metals (usually carbon steel and a more corrosion resistant, cathodic metal, such as copper), into the same electrolyte.
  - A zero resistance ammeter is used to measure the galvanic current between the two electrodes
  - If the environment becomes more aggressive, the electrical current between the electrodes increases
    - Advantages
      - Fast response time
      - Real time monitoring
      - Probes can be remote controlled to record and transmit data

- Sand monitoring probes
  - Sand monitoring is necessary for several reasons, to take remedial action before unexpected erosion failures occur on pipelines, wells and topside piping
  - Three major types of sand monitoring probes are used
    - ER probe (as covered in earlier slide)
    - Probe combined with a vacuum
      - If probe wears to a point that a leak develops, the vacuum is lost and an electrical signal is generated
      - A simple and reliable technique
    - Acoustic sand monitoring probe
      - The efficiency of acoustic sensors depends on the relative velocity of the fluid involved (next slide)

- Sand monitoring probes - acoustic probe
  - The efficiency of acoustic sensors depends on the relative velocity of fluids involved
  - Location of sand sensors is critical. The best positions are downstream of bends or flow restrictions