MARINE OIL SPILL PREVENTION
“BEST PRACTICES”

OFFSHORE PRODUCTION FACILITIES
AND SUBSEA PIPELINES

Vision: “To Achieve Clean Gulf”
Regional Clean Sea Organisation (RECSO)

MARINE OIL SPILL PREVENTION
OFFSHORE PRODUCTION FACILITIES AND
SUBSEA PIPELINES

Second Edition 2015

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Regional Clean Sea Organisation (RECSO)

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AND SUBSEA PIPELINES
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The principal objectives of RECSO are oil spill response and oil spill prevention. Oil Spill response at member facilities as achieved through a policy of mutual aid and assistance. Currently, RECSO is successfully implementing this policy with the help of a comprehensive, active and operational anti-pollution program since 1972. With the extensive network of pipelines and production facilities spread throughout the Gulf waters, prevention of hydrocarbon releases from these facilities no doubt proves much more successful in minimizing the detrimental effects of such releases than any measures taken to clean-up a spill.

During 1996-1997 the first Planning and Advisory Committee (PAC) together with marine experts from RECSO member companies recommended, after a detailed review of past marine emergencies, thereby avoiding major oil spillage. RECSO has organized workshops on this subject, assisting the operational marine staff of member companies to familiarize themselves with and to benefit from the programme.

After successful results from the first RECSO proactive project, the Second Committee, with relevant experts, was commissioned with assignments on prevention of oil spills from onshore (near shore) pipelines and tank farms. The committee has recommended a set of preventive operation and maintenance measures for those facilities.

The current PAC was established during 1998 with experts from RECSO member offshore operational facilities. This PAC was to examine the remaining major sector of oilfield operations with potential to experience significant hydrocarbon release, that is, offshore production facilities and subsea pipelines.
FOREWORD

The principal objectives of RECSO are oil spill response and oil spill prevention. Oil Spill response at member facilities as achieved through a policy of mutual aid and assistance. Currently, RECSO is successfully implementing this policy with the help of a comprehensive, active and operational anti-pollution program. Prevention of oil spills has remained at the top of RECSO’s agenda since 1972. With the extensive network of pipelines and production facilities spread throughout the Gulf waters, prevention of hydrocarbon releases from these facilities no doubt proves much more successful in minimizing the detrimental effects of such releases than any measures taken to clean-up a spill.

During 1996-1997 the first Planning and Advisory Committee (PAC) together with marine experts from RECSO member companies recommended, after a detailed review of past marine emergencies, a series of operational best practices”.

RECSO’s publication on oil spill prevention “Best Practices”, Terminals and Marine Vessel Operations” currently provides a guideline for terminal operators’ to safely handle tanker incidents, thereby avoiding major oil spillage. RECSO has organized workshops on this subject, assisting the operational marine staff of member companies to familiarize themselves with and to benefit from the programme.

After successful results from the first RECSO proactive project, the Second Committee, with relevant experts, was commissioned with assignments on prevention of oil spills from onshore (near shore) pipelines and tank farms. The committee has recommended a set of preventive operation and maintenance measures for those facilities.

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PURPOSE AND SCOPE

This report examines various potential oil spill risk factors for offshore production facilities and subsea pipelines, and makes recommendations to personnel directly involved in the operation and maintenance of offshore production facilities and subsea pipelines. The purpose of this report is to provide advice to personnel directly involved in the operation and maintenance of offshore production facilities and subsea pipelines. It is recommended that relevant business sections keep a copy of the guide and refer to it, as necessary, for design, operation and maintenance.

It should be borne in mind that in all cases the advice provided in the guide is subject to any overriding local or national regulations.
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It is recommended that relevant business sections keep a copy of the guide and refer to it, as necessary, for design, operation and maintenance “best practices”.

It should be borne in mind that in all cases the advice provided in the guide is subject to any overriding local or national regulations.
CHAPTER 1

PHYSICAL OCEANOGRAPHY AND WEATHER

1.1 Physical Environment and Oceanography
1.2 Weather
CHAPTER 1
PHYSICAL OCEANOGRAPHY AND WEATHER

1.1 PHYSICAL ENVIRONMENT AND OCEANOGRAPHY

The most important physical environment of the Arabian Gulf, Figure 1, with respect to the effects of marine pollution are its semi-enclosed shallow nature and its arid setting. The entire seabed is a sedimentary basin with outcrops of older limestone and a few actively growing reefs. This enclosed sea has a low rate of water exchange and consequently large parts of it experience extremes of salinity and temperature, which have considerable effect on the physical oceanography and the weather.

The bathymetry of the Gulf shallows to the northwest and to the west coast. An isolated trough extends northward from the Straits of Hormuz along the Iranian coast for approximately 100 km. The trough collects dense bottom water and impedes existing bottom flow. The weak bottom circulation into these depressions could lead to a build-up of oil pollutants.

Most river inflow into the Gulf occurs at the northern end, primarily on the Iranian coast. Annual rainfall in the arid climate of the Gulf region is small. Close to 7 cm yr\(^{-1}\). Evaporation in the Gulf varies from 144 to 500 cm yr\(^{-1}\).

1.2 WEATHER

Weather monitoring during offshore drilling activities continues to be confined mainly to simple observation, embracing wind speed and direction, sea state and perhaps temperature variations. The Gulf is an area of climatological extremes, characterized primarily by intense summer heat and frequent strong winds. However, there are also occasional freezing temperatures, intense
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1.2 WEATHER
Weather monitoring during offshore drilling activities continues to be confined mainly to simple observation, embracing wind speed and direction, sea state and perhaps temperature variations.

The Gulf is an area of climatological extremes, characterized primarily by intense summer heat and frequent strong winds. However, there are also occasional freezing temperatures, intense
though short-period rains, thunderstorms, and extended sandstorms.

The year can be divided into two seasons in this region, summer and winter. Summer is longer than in more temperate regions and is said to last from May until October with the hottest months being May through August. There is normally no rain during this period and evaporation is high. Relative humidity values are low for inland areas, though coastal humidities remain quite high, creating very high heat stress indices.

Beginning in late May or early June, an extensive low-pressure area develops over the Asian sub-continent as a result of early summer heating. The counter-clockwise wind circulation around this low is a permanent feature over and adjacent to the sub-continent during the summer. The eastern coast of Arabia lies on the southwest edge of this low-pressure zone and winds blow predominantly from a north to northwest direction. Increased winds during June and occasionally early July are known as “SHAMAL” from the Arabic expression for northwesterly wind. Sustained winds for 2 to 3 day periods at speeds of force “6” or more on the Beaufort Scale create blowing dust and limit visibility. Shamals with gusts of over 35 knots, lift sand sized particles several meters above the surface and dust to hundreds of meters, thus reducing visibility to under 1 km in coastal waters.

By mid-July there is no longer an appreciable pressure difference between Asia and Arabia and the still predominantly northwest winds weaken. Along the approximately 50 km wide coastal region, sea and land breezes modify the coastal winds primarily during summer. August is normally the calmest month, though the hottest. However, on a very rare occasion sudden risers to 60 knots of very short duration (20 minutes) have been recorded towards the end of August. Figures 2 and 3 provide wind roses for the Gulf area in February and June, respectively.

The fall months of October and November are a transitional period in which temperatures fall and relative humidity begins to rise. The Asian low-pressure area weakens and by November, the first winter
storms begin to affect the area. These extratropical frontal systems move eastward across the Mediterranean and the Middle East. As the centres of these storms approach the Gulf, the leading boundary of the warm front is for the most part poorly marked (sometimes as an occluded front, which turns the strong southeasterly winds to northwesterly winds, abruptly). These storms frequently produce sudden violent southeast or south winds known in Arabic as “KAWS”. The cold fronts are frequently marked by a sharp veer of the wind and sometimes with a squall and with cloud and rain. To the south in the Arabian Sea cyclones associated with the monsoons weaken as they approach southeast Arabia such that no cases have been reported in the Gulf.

The winter months of December through February are characterized by stormy periods with strong variable winds, some rain, thunderstorms and blowing dust interrupted by periods of relatively mild weather. February is usually the windiest month. Though rare, freezing temperatures have been recorded 8 days in January and February during the last 60 years along the west coast of the Gulf.

The winter storms diminish in frequency and intensity during the spring months of March and April, although local strong thunderstorms may occur during this period known in Arabic as “SARRAYAT” or sudden risers. These storms are very local in nature and are mainly observed in the northern part of the Gulf. Wind speeds of over 86 knots have been recorded and they usually last from 20 minutes to 1 hour, creating confused seas. These are normally associated with heavy rains and sometimes large hail stones. This phenomenon is very difficult to forecast, with tell tale signs giving very little warning. Blackened skies and a slight chill in the air are followed by the storms all within 10 to 15 minutes. Temperatures again rise with the approach of summer and the humidity decreases.

Although severe tidal anomalies are thought to be rare in the Gulf, tidal anomalies causing heights to differ from those predicted by up to 1 meter (3.3 feet) have been recorded. It is believed that
relatively stationary high pressure over the Gulf and low pressure over the Arabian Sea can cause an outflow through the Straits of Hormuz and so depress tide heights. The reversal of the pressure systems can cause an inflow through the straits and accordingly increase tide heights. Also, normal storm events cause water level set-up/set-down to the order of 25-40 cm. One episode in mid-January 1973 lead to widespread reporting of negative tidal anomalies in the 0.5 to 1.0 meter range throughout the Gulf. Figure 4 illustrates surface currents and circulation processes in the area.
From June to September the southwest monsoon in the Indian Ocean may maintain water levels in the Gulf up to one half meter higher than during the rest of the year.
It is expected that the information made available in this report will be used for maintenance scheduling and during planning and design of future developments. The extreme weather becomes a potential risk factor involving damage to offshore wells and subsea pipelines and all those associated with the running of day to day operations in the Gulf must be aware of its capability for rapid change.
Typical data for Bahrain (Gulf central) are provided in Table 1 to illustrate the broad range of weather conditions throughout the year and over the last few decades.
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Typical data for Bahrain (Gulf central) are provided in Table 1 to illustrate the broad range of weather conditions throughout the year and over the last few decades.

Figure 1
Physical Chart of the Arabian Gulf
Figure 2
Typical wind roses for the month of February
Figure 3

Typical wind roses for the month of June
Figure 4
Surface Currents

BAHRAIN INTERNATIONAL AIRPORT
LAT: 25°16'N    LON: 50°39'E ELEVATION: 2m
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COOLEST MONTH: MEAN MIN. TEMP. °C
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HIGHEST MAXIMUM WET BULB °C
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HIGHEST DAILY RAINFALL MM
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HIGHEST MONTHLY RAINFALL MM
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HIGHEST WIND GUST (KNOTS)
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MAXIMUM STATION PRESSURE hPa
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MINIMUM STATION PRESSURE hPa
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Source: Bahrain Civil Aviation Affairs Meteorological Directorate

**NOTE:** TRACE = LESS THAN 0.05 mm BUT MORE THAN ZERO
* OCCURRED MANY TIMES
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NOTE: TRACE = LESS THAN 0.05mm BUT MORE THAN ZERO

CLIMATOLOGICAL EXTREME CONDITIONS

| TABLE 1 | COOLEST MONTH: MEAN MIN. TEMP. °C YEAR | 15.00 | 17.44 | 26.90 | 21.69 | 13.33 |
| COOLEST MONTH: MEAN MIN. TEMP. °C YEAR | 10.82 | 12.19 | 14.48 | 19.71 | 23.94 |
| COOLEST MONTH: MEAN MAX. TEMP. °C YEAR | 19.20 | 21.70 | 24.16 | 26.70 | 31.43 |
| WARMEST MONTH: MEAN TEMP. °C YEAR | 22.67 | 25.00 | 28.84 | 31.52 | 36.77 |
| HIGHEST MONTHLY RAINFALL MM | 45.7 | 45.7 | 45.7 | 45.7 | 45.7 |
| HIGHEST DAILY RAINFALL MM | 54.8 | 40.09 | 67.9 | 64.0 | 9.2 |
| HIGHEST DAILY RAINFALL MM | 135.9 | 106.8 | 139.2 | 69.9 | 11.9 |
| HIGHEST WIND GUST (KNOTS) DAY/YEAR | 51 | 60 | 60 | 58 | 45 |
| MAXIMUM STATION PRESSURE hPa | 1013.1 | 1012.9 | 1026.1 | 1004.6 | 1019.8 |
| MINIMUM STATION PRESSURE hPa | 990.1 | 991.0 | 997.5 | 997.7 | 991.6 |

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Source: Bahrain Civil Aviation Affairs Meteorological Directorate
CHAPTER 2
Production Facilities

2.1 Introduction

2.2 Drilling and Workover Operations

2.3 Offshore Wells

2.4 Non-Wellhead Facilities

2.5 Fires

2.6 General Comments

2.7 Scenarios
CHAPTER 2
PRODUCTION FACILITIES

2.1. INTRODUCTION
A typical offshore oil field encompasses remote oil wells, satellite platforms, production stations and interconnecting piping systems. Drilling and workover operations, which is a part of the life cycle of an oil well, are carried out by offshore rigs, marine vessels, supporting the operations at all these offshore facilities.

This report identifies potential sources for spills or leaks from these facilities and operations and considers methods for preventing them.

2.2. DRILLING AND WORKOVER OPERATIONS
Operations that involve the risk of oil spills are:
- Rig movement and positioning of jack-up rigs
- Drilling, workover or clean-up operations
- Transfer of fuel from/to supply vessels
- Disposal of mud and cuttings to the sea.

2.2.1. Rig Movement
During rig approach towards jackets there is a potential for damage to wellhead jackets as a consequence of collision with a drilling or workover rig. This could result in an oil spill due to pipeline riser or Xmas tree damage. Another possible cause of oil spill would be if the rig or the mooring vessel damages a sub-sea pipeline. In order to overcome these problems the following procedures/precautions have been adopted during rig moves:
- For a new location, a detailed and comprehensive survey of the seabed has to be conducted before the rig moves to the location. In certain circumstances the insurers/surveyors may require coring samples to be analysed to check the condition and stability of the seabed.
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Rig movements in congested field areas are only done during daylight hours and under appropriate weather conditions. A suitable standby location “pin down” area for the rig must also be identified.

Before a rig moves the ‘Rig Mover’ together with the Barge Captain will verify and sign a pre-move checklist and will assess all the operational and safety aspects of the movement.

A Marine Officer coordinates jack-up rig and barge moves. A dedicated ‘Rig Mover’ should report to the Marine Officer and be responsible for the safe movement of the Rig. Figure 5 shows a jack-up rig under tow.

An approved mooring maintenance/diving vessel is sent to the proposed rig location where it will perform the following tasks:

Survey the seabed where the rig will be positioned. The seabed survey should be conducted over a radius of 300 feet from the working face of the wellhead jacket. The purpose of this task is: to ensure that the seabed is free of debris, to inspect the area for any existing seabed disturbances that may adversely affect the positioning of the jack-up legs and to confirm the current position of the pipelines. Divers may be used to conduct the survey. A survey report will be submitted to the Marine Officer.

Lay the necessary moorings in positions, in accordance with the Marine Officer’s approved anchor pattern, and mark existing pipelines with buoys.

Upon receipt of the diver survey report, the Marine Officer will prepare a “Rig Move Data Sheet” which will contain all the necessary information for the operation.

All concerned parties will review the Rig Orientation Diagram, the divers Seabed Survey Report and the Rig Move Data Sheet in order to agree on the specific approach and positioning conditions.

If the Rig moves to a jacket which does not have normally accepted conditions (i.e. annulus pressure that cannot be bled off) then this move will be highlighted to the next level of Operational Management.
Clear communication is to be maintained at all times during the move.

Before approaching the jacket, Rig Mover and Barge Master will assess the weather, sea state, and daylight conditions to authorise the movement.

As the Rig approaches the jacket it will lower its legs to a draft giving safe clearance above the seabed and any seabed installations such as pipelines.

When the towing has stopped, the rig will resume lowering its legs to the seabed and will ‘pin down’ (prior inspection must clarify that the area is clear of any obstructions). Where pipelines are present, the lowering of the legs will be carried out under strict observation of divers.

Jacking-up then commences to an agreed hull draft, at which point pre-load operations using seawater for ballast is carried out. The pre-load will be held for a specified minimum period after which the ballast will be discharged and the rig will be brought to its fully jacked-up position. The divers will be instructed to make final penetration check. Figure 6 shows a jack-up rig in position on a jacket.

When drilling operations are complete the rig will be moved off. This operation will require the same weather conditions, sea state and daylight conditions as for the move in. The rig will jack down until the legs are clear of any seabed obstructions. Moorings will be recovered systematically under the Marine Officer’s directions to ensure there is no interference with any sub-sea pipelines or other seabed obstructions.

2.2.2. Drilling/Work-Over/Clean-up Activities

There are a number of potential sources of oil spills during rig drilling, work-over and completion as indicated below:

- **Uncontrolled Flow or Blow-out**

  This can happen if mud weight hydrostatic pressure while drilling becomes less than reservoir pressure due to: i) gas kick. ii) lost circulation. iii) swabbing effect. To prevent this, a
correctly installed Blow Out Preventor (BOP) is used as standard pressure control equipment. The mud weight and fluid level in the hole is adjusted and monitored on a continuous basis to control the well during all drilling operations. All work is completed to the correct authorised procedures, standards and the Permit to Work system shall be enforced. Any oil spill must be reported.

- **Workovers**
  Before pulling the existing completion string out of the hole, the well must be killed by circulating killing fluid. In some cases oil spills could occur due to flow of oil while circulating killing fluids. To prevent this, oil present in the strings is either bull-headed into the formation of the oil is burnt using a burner boom.

- **Clean-up and Re-injection**
  During clean-up operations some oil droplets may be carried over to a long distance from the burner. These are heavy hydrocarbons; light components are normally burnt off. Optimising the ratio of oil and air can prevent this partial burning. This can be achieved using the new high efficiency, environmental friendly burners, called Green Burners. Minimising the quantity of oil burnt can also be achieved by re-injecting oil back into the production manifold at a certain stage during the clean-up operation instead of flaring it. Re-injection of the fluid virtually eliminates potential for the release of additional hydrocarbon. However, most facilities are not normally equipped to undertake this operation, as equipment must be configured to allow the re-injection. Appendix 2 provides additional detail on the operating practice and configuration for one such re-injection system.

**2.2.3. Fuel Transfer Operations**
In order to prevent hydrocarbon spills while transferring fuel from vessel to rig or vice-versa the following guidelines are recommended:
Obtain the weather report before the supply boat comes alongside the rig.
The mooring lines must be checked for proper strength and there should not be any visible damage.
Loading hose must be in good condition and should be checked for any visible damage.
Hose ends should be labelled and marked for fuel.
Hose connections (CAMLOCK) should be secured with safety pin installed.
Inform the boat captain about the required quantity of the fuel.
Check the battery condition and the radio channel for the communication system between the boat and barge.
Ensure that there is no hot work within 100 meters from the place of fuel transfer.
When boat starts pumping, a trained person with a radio must be placed in sight of the fuel station / hose / boat to watch for leaks or any abnormal condition.
When fuel transfer is completed, drain the hose back to the boat to prevent any hydrocarbon spillage to the sea.

2.2.4. Drilling Activities
The following potential sources of oil spills are normally encountered only during drilling activities:

Oil Contamination
Most operators avoid the use of oil-based mud (OBM) for their drilling operations because it is well known that these mineral oil based systems can cause harm to marine and bird life. There are new types of non-mineral OBM’s on the market, which are more environmentally friendly. These should be used whenever possible, especially when there is risk of spillage into the sea from unconverted rigs with no drip pans.
On occasion, diesel may be used in water-based muds to increase lubricity in the well and to help reduce free water across active shale zones. Glass beads and other
environmentally friendly materials such as natural or synthetic oils are now used for lubricity/torque reduction purposes. During drilling through the reservoir section, mud contacts hydrocarbon. However, one of the principle functions of mud is to form a mud cake against the wall of the hole preventing contamination of the mud with hydrocarbon.

**Mud and Cutting Disposal**

In certain countries there is increasing pressure to bring about a policy for zero dumping of drilling related fluids. In order to overcome the possible implementation of such regulations, operators are looking at new ways to deal with the potential problem. Operators are already improving the quality of shale shaker and solid removal equipment on their rigs in order to reduce the quantity of mud that has to be dumped due mainly to solid build up and the need to reduce weight by dumping and diluting mud. Some operators are already reporting a 50+% reduction in mud dumped through improved efficiency and installation of new technology solid removal equipment.

Reducing mud volumes does not reduce the amount of cuttings recovered at surface. Therefore, in order to eliminate offshore cuttings disposal they have to be recovered and shipped ashore for disposal at a suitable land location. Some onshore operators slurry the cuttings and dispose of them by re-injection into weak formation zones. In some fields in the North Sea this has now become standard practice.

**Toxic Materials**

The risk to the environment from dumping mud and chemicals to the sea can come from a variety of aspects but the most talked of topic is usually the toxicity of the chemicals used in the drilling mud. In recent years operators have undertaken several initiatives to remove the toxic chemicals and have successfully eliminated known toxins such as diesel, Para Formaldehyde, Chrome, Alum and Chrome Lignosulphonates.
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*Figure 5*

*Jack-up Rig under tow*
Figure 6

Jack up Rig in position on a jacket
2.3. OFFSHORE WELLS

2.3.1. Subsea Wellheads

Subsea wellheads that are producing hydrocarbons may be sources for possible oil spills. Dump flood wells supplying water from one zone to another for water injection, are excluded from this report as they typically have no potential to release hydrocarbons.

Potential sources of oil leaks from subsea wellheads or Xmas trees are:

- Valve leaks
- Physical damage to any tree component
- Material failure of any tree component
- Leaks caused by corrosion

Prevention of leaks can be accomplished through the following:

During the design stage, consideration should be given to installing protection frames over each wellhead. This will help to eliminate accidental damage to the wellhead itself. Also, it is prudent to use only valves and components supplied from a reputable manufacturer with a proven track record.

- Leaks occurring from tree valves
  - Only deploy valves designed for the products, flow rates and pressures expected from the particular well.
  - Inspect the sub-sea tree, with particular emphasis on the valves at specified intervals as recommended by the contractor or as indicated by the historical inspection records.
  - Ensure that maintenance schedules are fully complied with.
  - Ensure only authorised agents and personnel carry out any maintenance work.

- Leaks caused by physical damage to any tree component.
  - Strictly enforce exclusion zones ensuring that only authorised personnel have access.
  - Enforce a ban on all fishing in the area of subsea wellheads.
  - Strictly control all anchoring in the wellhead area.
  - Ensure that all oil spills, no matter how small, are reported.
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  - Strictly enforce exclusion zones ensuring that only authorised personnel have access.
  - Enforce a ban on all fishing in the area of subsea wellheads.
  - Strictly control all anchoring in the wellhead area.
  - Ensure that all oil spills, no matter how small, are reported.
- Strictly enforce a ban on dumping anything over the side of vessels.
- Insist that any accidentally dropped objects are reported.

❖ Leaks caused by material failure of any tree component.
- Inspect the sub-sea tree, with particular emphasis on any leaks at specified intervals as recommended by the contractor or as indicated by the historical inspection records.
- Ensure that any maintenance schedules are fully complied with.
- Ensure only authorised agents and personnel carry out any maintenance work.

❖ Leaks caused by corrosion.
- Inspect the sub-sea tree, monitoring corrosion rates at regular, specified intervals, as recommended by the contractor or as indicated by the historical inspection records.
- Ensure that the components are specifically designed for the products, flow rates and pressures expected from a particular well and then only operate the well within those parameters.
- Monitor and maintain cathodic protection systems to provide external corrosion protection.

2.3.2. Remote wells
In offshore fields there are numerous remote wells situated on remote wellhead jackets (see Figures 7 and 8). Some of these flow to a nearby satellite platform while others flow directly to the production stations. In either case the possible sources for oil spills are the same.

Potential sources of oil leaks from risers and topside pipe work are:
❖ The sub-sea flange connecting the riser to the pipeline.
❖ The riser bends at seabed level and any other bends in the riser.
❖ The region of the riser through the inter-tidal zone.
❖ Topside flange connections.
❖ Topside pipework
❖ Wellheads
❖ Instrument gas systems
Prevention of leaks can be accomplished through the following:

- Leaks from the subsea connecting flange.
  - At installation ensure that approved procedures are fully implemented.
  - Report and record all aspects of the installation procedure.
  - Use only specified materials for installation.
  - Ensure that the riser and all other components are manufactured to the specified standards.
  - Enforce a regular inspection program to monitor deterioration and corrosion rates.
  - Consider fitting protection frames over the riser bend and sub-sea connection.

- Leaks from the riser bends.
  - Ensure that this area has been properly designed and manufactured to the correct design specification and to the appropriate standard.
  - Inspect at specified intervals and take ultrasonic wall thickness readings to monitor erosion/corrosion rates at the riser bend.

- Leaks in the inter-tidal zone.
  - Ensure that at manufacture this area is correctly designed to the appropriate standard.
  - Inspect this region at the specified intervals, paying particular attention to any damage to coatings.
  - Monitor corrosion rates, both internal and external.

- Leaks from topside flange connections
  - These are similar to the seabed flange connection and therefore the recommendations made above apply.

- Leaks from topside pipe work
  - The possible sources for leaks from topside pipework are the same as for the risers and in this respect the pipework may be considered as an extension to the riser.

- Leaks from topside wellheads
  - The possible sources for leaks from topside wellheads are the same as for the subsea wellheads and other than for the
provision of wellhead cages the recommendations made for subsea wellheads apply. Figure 9 shows a typical offshore wellhead configuration.

- Leaks from instrument gas systems
  - Some of the older platforms offshore use a method of gas utilization, which in some circumstances will be a source for an oil spill. The method involves tapping into the oil line at the Top Dead Centre (TDC) of the pipe. Gas coming up from the reservoir with the oil is concentrated at the top of the pipe and the tapping bleeds some of this gas off. This gas is then used as instrument gas for control unit operation. During a shutdown there may be an over-pressure in the bleed line and the only way to deal with this currently is to dump directly to the environment. This causes minor oil contamination to the environment while the tap line drains.
  - The system should be redesigned so that this equipment is replaced and the older method is discontinued. This will involve laying an umbilical to provide instrument air or power from the main complex or installation or solar powered air compressors on these wellhead jackets.
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Figure 7
Illustration of a typical 6-well jacket from seabed to heli deck.
Figure 8
Illustration of a typical remote wells and remote wells jacket
Figure 9
Typical wellheads
2.4. NON-WELLHEAD FACILITIES

The following factors have been identified as major risks for potential for release of hydrocarbons from offshore production facilities other than wellhead platforms. While these facilities differ from wellhead platforms mainly in the fact that they have no wellheads and are not typically visited by drilling or workover vessels, many of the factors discussed below will also apply for wellhead platforms. Production facilities may include, but are not limited to, tie-in platforms, gas oil separation plants (GOSPs), (see Figures 10, 11, and 12).

Risk factors are:

- Corrosion
- Physical Movement
- Accidental impact
- Pressure Surge
- Thermal Stress
- Maintenance Activities
- Operations Activities
- Containment and Emergency Systems Failure

Once potential hydrocarbon release risk factors have been identified, measures can be taken to eliminate, reduce or control the release. The following sections address some of the more significant actions that can be taken to prevent releases from the identified sources. In most instances, a number of actions listed will work in concert to prevent leaks. As such, it is not implied that any one measure is better than another is or that only one control measure need be applied.
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Figure 10 – Major offshore multi-platform production facilities
Figure 11
Major offshore multi-platform production facility
Figure 12
Construction barge moored on location at a production facilities
2.4.1. Corrosion

2.4.1.1. External

- Material selection

Control of external corrosion is less frequently addressed through materials selection than through the measures discussed below. Caution is advised when selecting corrosion resistant alloys to address internal corrosion problems, as the application of some of these materials in the high chloride marine environment can lead to externally initiated failures.

- Protective coatings

Metallic Monel sheathing has been used extensively in offshore environments to protect structural members and process carrying lines that pass through the splash zone. It is virtually unaffected by corrosion and can provide long term protection of the underlying steel structure. Its copper content may also provide anti-biological and anti-fouling properties. The material is relatively easy to apply in the construction yard. However, it is thin, prone to damage on impact, and difficult to repair in situ.

Non-Metallic

Metallic components above the splash zone are typically coated with environmentally resistant paint systems. These systems are pigmented with bright colours; e.g. yellow to provide enhanced daylight visibility.

Fibre reinforced plastic (FRP) materials are now being considered as replacements for Monel as protection for structural members and piping in splash zone areas. These systems offer a broader range of application and repair environments and are less prone to significant impact damage.

- Cathodic protection

Steel structures and pipelines continuously immersed in seawater can be effectively protected from external corrosion through the application of cathodic protection, either from...
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Non-Metallic
Metallic components above the splash zone are typically coated with environmentally resistant paint systems. These systems provide the bulk of a structure’s resistance to atmospheric corrosion. The systems typically are pigmented with bright colours; e.g. yellow to provide enhanced daylight visibility.

Fibre reinforced plastic (FRP) materials are now being considered as replacements for Monel as protection for structural members and piping in splash zone areas. These systems offer a broader range of application and repair environments and are less prone to significant impact damage.

Cathodic protection
Steel structures and pipelines continuously immersed in seawater can be effectively protected from external corrosion through the application of cathodic protection, either from
galvanic or impressed current systems. New jackets are typically installed with galvanic protection already in place. Larger structures such as GOSPs, compression platforms, etc., may be more economically protected with impressed current systems if electrical power is available.

- **Inspection**

  Visual examinations of external structure and pipe surfaces are the most frequent mechanism for detecting external corrosion. Coated surfaces often show visible rust staining on failure of the coating. In the initial stages this rust staining, is basically a cosmetic concern, but if left unattended severe metal loss, particularly in the form of pitting corrosion, may result.

  Visual inspection may also provide the first hints of more significant internal problems. Dead legs or low-pressure lines may actually begin to weep externally as a result of penetration of the pipe wall at the bottom of a pit or corrosion lake. Drips on the deck plate or runs on piping surfaces can be evidence of otherwise undetected internal damage.

2.4.1.2. Internal

- **Material selection:** Carbon steel is the most common material used to fabricate process equipment and piping. For the majority of service conditions, carbon steel has acceptable corrosion rates and can be utilized for the life of the facility. Occasionally, service conditions are severe enough to warrant the use of corrosion resistant metallic alloys or non-metallic materials. Caution must be exercised when using corrosion resistant alloys for piping systems, as the methods used for their fabrication can differ greatly from carbon steel fabrication practices. Application of an incorrect fabrication technique can result in extremely rapid environmentally induced cracking or corrosive failure.

  The consequences of coupling dissimilar metals in a corrosive process stream must be considered prior to the alloy selection. Effective electrical isolation may be required to reduce inherent galvanic effects. In addition to the main component
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Design
Dead leg elimination: Dead legs can be defined as sections of process piping that, under normal operating conditions, contain stagnant fluid. Dead legs typically also have one open path to the process stream, although it may be possible to completely isolate some piping sections. Because this definition can include a very large number of common process attachments, and as there is typically some fluid exchange due to turbulence effects in short sections, many operators choose to further qualify the definition by requiring the isolated section to be more than three (3) pipe diameters long before it is considered a dead leg.

Designing for the elimination of dead legs is the most effective mechanism to reduce internal corrosion resulting from their presence. Most often, the design changes required to eliminate dead legs are quite minor, such as the relocation of isolation valves as close as possible to the active stream. Provisions for drainage of a piping section where valve placement cannot be modified can reduce the potential corrosion problem caused by stagnant fluids. If no piping design modifications are possible, then operational adjustments may be considered, such as allowing continuous flow through the section in question, thereby eliminating the hold-up of stagnant fluid.

Containment structures:
Where spillage of some hydrocarbon is inherent to a particular operation, e.g. pump suction removal and cleaning, then
containment structures with or without drains can provide protection against spread of the release. These containment structures, particularly those with drains connected to slops collection systems, can also prevent spread of unplanned releases resulting from pump seal failure, storage tank overflow, etc.

Solid decking:
As with specific equipment containment structures, entire platforms can be constructed with solid deck plating and drain systems. This provides for collection of hydrocarbon releases in areas where specific containment structures would be unfeasible. Releases are thus retained on the platform and routed to some form of slops collection system through a structured drain system. Drain systems can be either wraparound gutters or external skirting with deck collection openings. All deck penetrations should be skirted to prevent overflow through the penetration.

Slops collection:
In addition to the planned collection of hydrocarbon releases, the solid deck plating also becomes a barrier to the passage of rainwater. The system must therefore be designed to allow for the collection of large volumes of rainwater or for the emptying of the storage vessel, normally to the process stream, under automatic level control. In the past, slops collections systems have made use of caissons open on the bottom to the sea. This allows collected water to pass through to the sea with hydrocarbons being skimmed off the top. However, these systems allowed the entire caisson to fill with hydrocarbons to the point where all the water was displaced and the hydrocarbons were released to the sea. The majority of slops collection systems now make use of a totally enclosed vessel to reduce the potential for such releases. All new slops systems should be of the totally enclosed design, and older open-ended caisson should be replaced on a planned basis with enclosed vessels.
2.4.1.3. Chemical treatment

As previously indicated, carbon steel will provide adequate service life in the majority of process conditions. However, there are situations where it is not economically feasible to use corrosion resistant alloys, even though the process environment is too harsh for carbon steel. In these situations the environment is modified by the addition of chemical corrosion inhibitors. These chemicals provide protection to the carbon steel, reducing the corrosion rate and extending the life of the component to an acceptable time frame.

- **Chemical residual monitoring**
  Corrosion control chemicals added to a system can be monitored for their presence and concentration throughout the system from the chemical injection point to the final delivery point. Residual chemical is to be present at some predetermined minimum level throughout the system in order to maintain adequate protection. Verifying the presence of the required residual is one method to ensure that the system being treated will be protected.

2.4.1.4. Inspection

Oil spills can be prevented if a component that is about to fail is repaired or replaced prior to failure. This implies that the condition of the component is known or can be determined. Various inspection technologies have been developed to assess the condition of a component. These technologies, for the most part, allow examination of a component without removing it from the system or shutting down operations.

- **Ultrasonic inspections**
  Ultrasonic signals can be used to determine the thickness of a component. This requires contact of the signal-generating probe with the outer surface of the component being tested. No access to the internal surface or interior of the component is required. Metal loss resulting from corrosion can be observed by the detection of reduced metal thickness. Thickness comparisons are made with the surrounding areas or
with measurements taken previously at the same location. Anomalies within the metal itself that cause the ultrasonic signal to be reflected are detectable and can shield the internal surface behind it from effective examination. These anomalies may not be distinguishable from internal corrosion-caused metal removal. Use of other ultrasonic signals, e.g. shear wave or angle beam or radiographic examination, may be required to verify the presence or absence of internal corrosion.

**Radiographic inspections**
Radiographic imaging can reveal changes in wall thickness resulting from corrosion. The image produced on photographic film as a consequence of exposure to radiation will indicate sections of reduced wall thickness as areas darker than the surrounding material. Radiographic examination is relatively rapid on smaller, thin materials and does not require access to the interior of the equipment being examined. Coverage is limited by the size of the film used, and therefore this method may prove uneconomical where extensive areas are to be examined. Liquid-filled equipment or equipment containing large amounts of solids or sludges may adversely affect the image obtained.

Personal safety must always be a concern where exposure to radiation is possible. Inspections on manned platforms may therefore be limited to areas that can provide restricted access, or in more exposed areas to periods when personnel traffic is reduced, e.g. nigh shift.

**Magnetic flux leakage inspections**
New instruments have been developed that use the magnetic flux leakage principle so scan large areas of piping rapidly to detect localised wall loss. The areas identified by this technique can then be more closely scanned by ultrasonic or radiographic techniques to quantify the magnitude of the metal loss more accurately.

**Visual inspections**
The opportunities for the use of visual inspection for internal corrosion prevention are usually limited in scope and restricted to those occasions where facilities are opened for normal testing and inspection (T&I) or to when system components are removed for maintenance, repair or replacement. Because these visual inspection opportunities are infrequent they should be used whenever possible to examine the internal surfaces of the exposed equipment for signs of corrosion, erosion or wear.

2.4.1.5. Corrosion Monitoring
Another method to detect and assess corrosion activity is to specifically introduce components into a system for that purpose. Measurements of this type can be considered indirect, as they do not measure the corrosion of system components but the rather corrosion of the component introduced to obtain the information. With some limitations, it may be inferred that corrosion observed on the measurement device is also occurring in the system under investigation. Several of the more common monitoring devices are discussed below.

- **Coupons**
  Coupons are usually fabricated from a material of a composition similar to that of the bulk system to be monitored. The coupon is inserted into the system and thus exposed to the process fluids and conditions. After a given period of time the coupon is removed and the weight after exposure compared with the weight prior to exposure. The mass loss can then be converted to a corresponding corrosion rate, usually expressed as thousandths of an inch or millimetres per year in thickness.
  As with any monitoring technique, the placement of corrosion monitoring devices is essential to collect data representative of the system being monitored. If the coupon is placed in the system in an area not characteristic of the conditions throughout the system then the corrosion rates obtained on
the coupon will not reflect the corrosion rates in the equipment under investigation. Coupons are best suited for measurement of general corrosion but can be used to detect pitting corrosion. Coupons may also be used to monitor sessile biological population sizes and changes.

- **Probes**

  Probes differ from coupons in that they typically remain in the system and instruments are used to monitor changes in probe parameters from outside. Probes are not removed for examination or data collection purpose. They are only removed for repair or replacement at the end of their useful life.

  Probes can be split into two broad categories: metal loss types or electrochemical types. Metal loss types monitor material loss from the probe due to corrosion or erosion. Electrochemical types measure the corrosivity of an environment independent of actual material loss.

  Placement of probes must be done with the same caveats as coupons. The probe must be located within the system in the environment that requires monitoring.

2.4.2. Physical Movement

2.4.2.1. Wind Action

- **Design**

  Placement of structures should be such that the long axis of the facility is as close to parallel to the direction of the prevailing winds as possible. This alignment will present the minimum area to the wind forces.

  When designing structures the one minute mean wind speeds for the 100-year recurrence and the one minute mean wind speeds for the one-year recurrence should be used for the extreme and operating design conditions, respectively.
Individual components of the deck and facilities should be designed using the three-second gust wind speed for the 100-year extreme.

2.4.2.2. Wave Action

- **Design**
  When designing structures the maximum wave heights for the 100-year and one-year recurrence periods should be used for the extreme and operating design conditions, respectively. The apparent increase in diameter of all members from marine growth and ancillary appurtenances should be accounted for in the design when calculating loading. Additionally, where riser spacing is less than 3.5 diameters, centre to centre, solidification effects should be considered.

2.4.2.3. Production Associated Vibration

- **Design**
  During production of multiphase fluids, piping movement may occur. This may result from passage of liquid slugs, passage or receipt of scrapers, control valve fluctuations or emergency releases to flare. The normal ridge clamping, attaching the equipment to the structure will control the majority of process-induced movement and vibration. However, some vibrations, such as those that may occur during emergency flaring operations, may require additional clamping and placement of braces. Computer simulations can often identify pipe sections and equipment that may vibrate excessively under abnormal conditions. Modifications can therefore be made prior to the actual emergency condition.

2.4.3. Accidental Impact

2.4.3.1. Design

- **Boat landing placement**
  Boat landings should be placed whenever possible on the lee side of the structure. Depending on their design, boat landings may offer additional protection for internal risers. However, the trade-off between the possible increased protection and
the increased potential for damage due to higher traffic should be carefully considered in the design phase.

- **Riser placement**
  Risers placed internally to the outer structure members provide the best impact protection. However, such placement may be difficult to provide on all structures, and expensive to retrofit on existing structures. In those instances, riser protection guards should be provided. These guards should be designed to sustain some damage as they absorb the energy of impact. In general, risers should be located away from areas that will encounter heavy vessel traffic.

### 2.4.3.2. Navigational aids

- **Marker lights**
  Marker lights should be provided for all offshore structures. “Recommendations for the Marking of Offshore Structures” issued by the International Association of Lighthouse Authorities (IALA) should be followed when providing for marker lights. The following information can be used as a minimum general guideline:

| Structures having a maximum horizontal dimension of 9 m (30 ft) or less | 1 marker light |
| Structures having a maximum horizontal dimension of over 9 m (30 ft), but less than 15 m (50 ft) | 2 marker lights on diagonally opposite corners |
| Structures having a horizontal dimension of over 15 m (50 ft) | 4 marker lights (1 on each corner) |

The IALA issues other recommendations concerning marker light intensities, colour, and rhythmic character, etc. Those documents should be consulted as necessary.
Foghorns
Foghorns are generally placed on selected structures at the perimeters of the offshore producing area. Again, the IALA document “Recommendations for the Marking of Offshore Structures” should be consulted concerning this equipment.

Helideck placement
There should be a minimum of three unrestricted obstacle-free approaches to any helideck. If the fourth approach is obstructed, the obstruction should not be closer than 6 m (20 ft) to the helideck edge. A helideck shall be located in electrically nonclassified areas. It should also be located at least 7.5 m (25 ft) above any hydrocarbon release point.

2.4.3.3. Ship Movement Procedures
Large ships should be prohibited from approaching any producing facility. Movement of large ships should be restricted to the periphery of any offshore field according to applicable maritime navigational regulations.

Vessels navigating within field boundaries should be made aware of all pipeline locations, shallow water, coral or other obstructions, and safe anchorage areas. All vessels should be equipped with radar for navigation at night and during periods of low visibility or adverse weather conditions.

Vessels should not be allowed to approach inter-platform connecting structures, such as personnel walkways or bridges or interconnecting pipe racks. Passage beneath any of these structures, except under strictly controlled work conditions, should be prohibited.

2.4.3.4. Structure Inspection
In addition to the inspections described in sections 2.4.1.1 and 2.4.1.4 above, which dealt mainly with the process piping and equipment, the jacket or structure itself must also be examined periodically to determine its integrity.
Visual Inspections
Divers/remote operated vehicles (ROVs) should conduct a general overall examination of the structure for bends, dent, gouges and other signs of obvious structural damage. Notations should be made on seabed status, i.e. excessive scour, evidence of severe leg penetration, and presence and location of any areas of excessive debris accumulation.

Cathodic Protection (CP) Status
CP potential readings should be taken around the jacket prior to any other action. CP readings should be obtained from each stage or level from the seabed to the splash zone. Sacrificial anodes should then be surveyed taking note of their number (total count), location, anode type, anode origin (original installation or retrofit) and condition (estimated percent depletion). Each anode should then be cleaned of marine growth and calcarceous deposit and anode attachment integrity should then be checked. A new set of potential readings should be taken at all nodes and joints and on the members to which the anodes are attached. Figure 13 shows pre-fabricated replacement anodes ready for installation.
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Figure 13
Anodes – Pre-fabricated replacement anodes
Weld Examination
A percentage of the structural member welds, both complex and simple, should be cleaned of all marine growth and then to a near-white metal finish. Cleaning shall extend to 15 centimetres (6 inches) on either side of the weld and shall include all braces within 15 centimetres of the weld and all stiffeners at the weld. A close visual survey should then be conducted to check for visible cracks or signs of extensive corrosion. Magnetic particle inspection may be required to assess the status of some complicated welds or to delineate fully the extent of observed cracking.

Flooded Member Detection
This examination is typically done for the first inspection after a platform is built and then at five or 10-year intervals, depending on whether the platform is manned or unmanned. Follow-up or more frequent surveys will be set up on a case-by-case basis if flooded members are observed.

2.4.4. Overpressure and Pressure Surge
2.4.4.1. High and low pressure shutdown devices
High and low pressure shutdown devices can reduce the magnitude of a spill by shutting down and or isolating the effected component should a process upset result in an abnormally high pressure or breach of integrity. However, to be effective this equipment must monitor the process in question 100% of the time. Therefore, these devices must be adequately maintained and their continuing function assured to keep releases to a minimum.

2.4.4.2. Slow-acting valves
Where the rapid closing of a valve could generate a pressure surge or hammer effect, slow-acting valves should be considered. Pressure surge can be extremely destructive, and consideration should be given to the installation of slow-acting valves in services where pressures resulting from rapid valve
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closures cannot be dissipated. These valves have a controlled rate of closure and cannot slam shut and create a surge.

2.4.5. Thermal Stress

2.4.5.1. Design
Although the majority of processes encountered in offshore hydrocarbon production can be considered to be intermediate temperature processes at best, well below the creep temperatures, thermal stresses should be considered in the overall system design. The most likely frequent result of applied thermal stress is leaks at flanges resulting from expansion. Following proper torquing procedures should significantly reduce the occurrence of such leaks. In the event that leaks do occur, passive containment measure, e.g. solid decks, slops systems, etc., should be in place to collect the release.

2.4.6. Maintenance Activities

2.4.6.1. Breaking system integrity

- **Pump Maintenance**
Pumps and other types of rotating equipment typically require frequent maintenance to keep them in top operating condition. Most pump maintenance activities require that pumps be disconnected from the process stream in some manner. Hydrocarbon releases are to be expected in these situations. However, the magnitude of a release is controllable, and where individual containment structures are present, the potential for the release to surrounding is limited. Pumps should not be located on grated decks or in areas without secondary containment. Consequences of releases during routine maintenance can be further reduced in this manner.

- **Valve Maintenance**
All hydrocarbon-processing facilities must occasionally remove valves for repair or replacement. As these activities are
Normally pre-planned well in advance, hydrocarbon releases should be easily controlled and minimised. However, careful attention must be given to properly isolating and draining the piping and equipment affected by the valve removal. Large systems should be drained slowly or in stages so that the slops collection system is not overwhelmed.

Caution is advised when breaking the system integrity. Some residual fluid is to be expected when the system is opened. However, if the fluid flow does not stop after a reasonable time it should be assumed that part of the process has not been properly isolated. This can be the result of open valve, presence of unidentified cross-connections or failure of an isolation valve. In any eventuality, provisions should have been made for collection of larger than anticipated volumes and for the immediate reestablishment of system integrity to stop the release.

- **Vessel Inspections**
  
  Prior to inspection of a process vessel, it must be drained and cleaned. Process fluids normally contained within the vessel must be diverted to the slops system. As process vessels typically are a much large volume than the slops collection vessel, care must be taken that the fluid transfer rates are low enough to prevent overfilling the slops vessel. These operations should be under manual supervision at all times. This will enable more rapid response to abnormal conditions in the slop collection system, which could, lead to a hydrocarbon release.

2.4.6.2. External Operations

- **Structure Cleaning**
  
  Clean-up of spills or releases should be conducted in such a way that the cleaning operation is not itself a source of discharge to the water. When pressurized hoses are used for cleaning the spray pattern should be kept to the minimum necessary to remove the contaminant, not forcing the spill off the structure.
Where cleaning operations require large volumes of water, the slops re-injection system should be checked prior to cleaning. This will reduce the potential for inadvertent overflow of the slop system. Additionally, where cleaning may produce water at a rate higher than the slop system discharge rate the cleaning should be staged so that high levels are not created in the slops collection vessel.

2.4.7. Operations Activities

2.4.7.1. Breaking system integrity

- **Scrapping**
  Both routine cleaning scraping and instrument inspection tool scraping require that system integrity be broken at the launcher and receiver so that the scraper can be inserted and removed. Scraping facilities should be designed with drain lines directly into the slops collection system. Additionally, to contain the fluids that inevitably remain in the oversize portion of the barrel, grated catch basins should be designed into the deck beneath the launcher and receiver doors. These catch basins should also drain into the slops collection system.

  Seawater purge systems should be installed to flush out as much of the hydrocarbon remaining in the trap prior to opening the door for placement or removal of the scraper. These purging systems significantly reduce the potential for hydrocarbon spillage by effectively displacing residual hydrocarbon with seawater.

- **Sampling**
  Process monitoring often requires that samples of the fluids in the various system streams be obtained for analysis. Every time system integrity is broken to obtain samples, potential leak sources are created. The use of low volume sample pots that can be isolated from the system flow prior to collection of the sample effectively limit the amount of fluid that can be discharged from the system should difficulties occur. Double
valves for sample points where sample pots are not feasible
provide an emergency backup for a valve that may fail to close
due to corrosion or solids build-up.

Sample locations should be placed around the structure only in
areas where any inadvertent spillage will be contained and
drained to the slops collection systems. Sample points should
not be located in areas with grated decks or on parts of the
structure where loss of containment at the sample point could
result in direct discharge to the water.

2.4.7.2. External Operations

Cleaning

As indicated in section 2.4.6.2, any cleaning operation should
be conducted to ensure that it is not the source of
hydrocarbon release to the water.

2.4.7.3. Flaring

Flaring of produced fluids is probably the one normal
operational activity with the highest potential for discharge of
hydrocarbons to the water. As such, flaring should be kept to
the minimum necessary for safe operation.

Since some flaring will always be required, measures should be
taken in both system design and operation to reduce the
likelihood of hydrocarbon release. Designs should ensure that
flare knockout drums are incorporated into the system, and
that those vessels are sized for the maximum anticipated
flaring rates. Vessel level controls and alarms must be in place
and their functioning assured and maintained. Except for
emergency situations, liquid collected in the knockout drum
should be automatically pumped back into the process or
discharged into the shipping lines.

Operationally, flaring should be conducted when possible at
rates below the maximum allowed by vessel design. This will
reduce the potential for liquid carry-over by reducing the
velocity through the knockout vessel. Flaring at reduced rates
also provides, better opportunity to obtain complete
Combustion at the flare tip, resulting in reduced discharge of unburned material.

2.4.8. Containment and Emergency Systems Failure
Failures of containment and emergency systems are anticipated to be rare as these systems are backups by design, and are expected to be serviceable in the event of failures of other components. However, contingency plans should be developed for external control of hydrocarbon releases from these systems or from other systems as a result of backup system failure.

2.5. FIRES
Fires on offshore structures are in themselves catastrophic events and their prevention should always be a high priority. However, the consequences of fires can often be overlooked because the fires themselves are disastrous occurrences. One of the more significant consequences of an offshore structure fire is an oil spill. These spills may be prolonged releases of large volumes due to the extensive structural damage typically observed in fire situations. The detrimental effects of consequent oil spills should provide additional reinforcement for practices put in place to prevent the occurrence of fires. The list provided below identifies some of actions that may be taken to prevent fires and consequent oil spills. The listing is not meant to be all-inclusive, but to highlight several of the major preventative measures.

- Strict enforcement of the permit to work system.
- Strict enforcement of the Hot work permit.
- Strict enforcement of electrical area classification.
- Use of spark arrestors on all internal combustion engines.
- Strict enforcement of the management of gas storage cylinders.
- Strict enforcement of no smoking areas.

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Display “No Smoking” signs prominently where appropriate.

Conduct frequent fire safety drills and exercises.

2.6. GENERAL COMMENTS ON OIL SPILL PREVENTION MEASURES

There are a number of general background factors that should be examined in conjunction with counter-measures previously recommended.

2.6.1. The vast majority of accumulated oil spilling into the environment comes from small spills and leaks. These can be controlled by careful attention to detail at the design stage itself, for example, requiring spill tray to be fitted where appropriate and incorporating any new equipment into the platform slop system.

2.6.2. Major oil spills, from tankers, blowouts or fires, for example, while they appear to be more damaging to the environment have less long-term impact than the effects of chronic small leaks occurring over a long period of time. Chronic leaks can be eliminated by the correct application of inspection, maintenance and repair schedules conducted at regular determined intervals.

2.6.3. Oil spills, no matter how small, should always be reported to the concerned authorities. Management, department heads, section heads and line supervisors should encourage the reporting of all oil spills.

2.6.4. Dispersed oil may be considered as “out of sight” and therefore “out of mind”. However, it is still in the ecosystem and capable of causing long term environmental damage. Dispersants should be used only as a last resort and after authorization by the appropriate oil response officer.

2.6.5. It is extremely important that Oil Spill Response Plans be kept under constant review and are updated as frequently as necessary. This will ensure that the correct response using the most updated
knowledge and advice is applied whenever needed. It will also have the effect of heightening the awareness of all staff to this problem. This can best be achieved by encouraging regular, minuted meetings between all the interested parties.

2.6.6. Frequent Oil Spill Response exercises will also confirm that current plans are workable, and will heighten awareness of the problem, foster better co-operation between the various companies and reinforce measures taken to make necessary amendments to individual response plans. These exercises could be, for example, monthly and should progressively cover all aspects of oil spill response measures.

2.6.7. Periodic deployment of the specialized equipment will ensure that staff responsible for deployment knows what is required. It will ensure that the equipment is serviceable and has been maintained in accordance with the established maintenance schedules. Furthermore, it should ensure that all equipment is stored at the correct location. This deployment is most often incorporated into regular, oil spill response exercises.

2.6.8. The Permit to Work system is a very important component of the overall strategy to prevent oil spills. Proper control of all work activities is essential in managing minor spills.

- Another vital aspect is that all work is carried out to the correct procedures, which are updated as required to keep abreast of new developments.
- Similarly all work carried out must be completed to the required standard using specified and certified materials.

2.6.9. Finally, it is most important to underline the need to report all oil spills, no matter how small. This will help in many ways not the least of which are:

- It will heighten awareness
- It will maintain a meaningful oil spill incident register
- It will ultimately provide data, which can be used to pinpoint causes of spills, and therefore lead to more effective counter measures being evolved.

2.7. INCIDENT SCENARIOS

The following hypothetical incident scenarios serve to illustrate possible outcomes of a pump failure where spill prevention measures were not or were incorporated into the design and placement of the pump. The scenarios do not differ greatly in the decisions made or in the chain of events that led up to the failures. However, they differ significantly in the consequences of the failures with the resulting discharge or collection of released crude.

2.7.1. Scenario A: An Uncontained Oil Spill

A new centrifugal, crude transfer pump is purchased for an existing offshore platform. The pump is to be located next to an existing pump to act as backup for that pump. However, there is not enough deck space to accommodate the new pump and an extension is added to provide the required surface area. Because the pump is a self-contained skid-mounted unit complete with a self-draining containment structure, it is decided that the extension will be floored with grating rather than solid plate. The skid drains will be piped into the platform slop system for collection of any spills. The pump is installed and commissioned without incident. However, there is a delay in arrival of the piping necessary for completion of the connection of the skid drains. It is decided that this is not sufficient reason to delay placing the pump on stand-by status as the existing pump has not encountered any recent problems and is not anticipated to require work prior to completion of the drain system. The pump is placed on line in the standby mode.

Several weeks later the original pump starts to show increasing vibration levels for the in-board bearing. A new shift with a new supervisor had come onto the platform several days before and they were aware that there was now a stand-by pump available for this service. However, there is no mention in the change over record that the drain system on the new
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The pump is installed and commissioned without incident. However, there is a delay in arrival of the piping necessary for completion of the connection of the skid drains. It is decided that this is not sufficient reason to delay placing the pump on stand-by status as the existing pump has not encountered any recent problems and is not anticipated to require work prior to completion of the drain system. The pump is placed on line in the standby mode.

Several weeks later the original pump starts to show increasing vibration levels for the in-board bearing. A new shift with a new supervisor had come onto the platform several days before and they were aware that there was now a stand-by pump available for this service. However, there is no mention in the change over record that the drain system on the new
pump was still not complete. The shift supervisor orders that the new pump brought on line and the old pump shut down for maintenance.

The next day, a sheen is observed on the water surface tailing away from the platform with the current. A search for the cause of the sheen is immediately begun and it is found that there is a leak on the packing of the new crude transfer pump. Since it is assumed that a drain system was installed with the pump and the packing is still quite small, it is left for Maintenance to repair and the search for the source of the leak is continued.

On further investigation, the gap in the drain system is found and identified as the source of the discharge. The packing on the new pump is adjusted and the leak stopped. Because the old pump has been dismantled for repair and cannot be returned to service, the drains of the new pump skid are plugged to stop discharge from any further packing leak and the new pump is left in service. The shift supervisor orders the operators to check the new pump packing every two hours to insure that if there are any further leaks the pump skid containment system will not be over-filled. The volume of crude spilled off the platform is estimated to be approximately five barrels.

Several days later there have been no new packing leaks and the shift supervisor orders the new pump packing to be checked for leaks every twelve hours. The old pump is still out of service awaiting the arrival of spare parts.

Early the following day the operators check the pump packing and find no leaks. Several hours later a manufacturing flaw in the outboard bearing of the new pump begins to manifest itself and the pump begins to vibrate severely. Within minutes the packing begins to leak and crude starts to fill the containment structure of the skid. The pump vibration steadily increases until the suction flange of the pump, already under stress from a slight misalignment of the inlet piping, fractures.
near the pump casing. Crude begins to leak from the crack at a high rate. The skid containment system, already almost full from the progressively worsening packing leak, overflows and crude starts to spill through the grated deck into the water.

Pressure in the shipping vessel feeding the transfer pumps starts to drop rapidly and the low-pressure alarm sounds in the control room. Operators are dispatched to determine the cause of the pressure decrease. System pressure continues to drop and the low-low pressure shut down system shuts in the platform. The transfer pump is stopped automatically on shutdown of the platform. However, there is still a level in the vessel and it is partially pressurized. Vibration of the pump prior to its shutdown had opened the casing crack to 50 percent of the inlet circumference, and crude spills from the pump at an increased rate.

On their arrival at the shipping vessel, the operators observe crude coming from the transfer pump and immediately close the suction and discharge valves. The leak slows and slops. The control room operator reports that the pressure in the system has stabilized. The operators at the pumps note that crude has spilled off the platform and request that the control room operator advise the supervisor and initiate the emergency response for an oil spill containment and clean up. The operators indicate that they will continue to look for possible secondary leaks and insure that the system is completely isolated.

Total crude spilled off the platform by the pump failure is estimated at 100 barrels. Total crude release from both the packing leak and the failure is 105 barrels. Total crude spilled of the platform by the pump problems is 105 barrels.

2.7.2. Scenario B: A Contained Oil Spill
A new centrifugal, crude transfer pump is purchased for an existing offshore platform. The pump is to be located next to an existing pump to act as backup for that pump. However,
there is not enough deck space to accommodate the new pump and a deck extension is added to provide the required surface area. Even though the pump is self-contained skid-mounted unit complete with a self-draining containment structure, it is decided that the extension shall be floored with solid plate rather than grating. This provides an additional level of spill control, as the new deck area will have its own drain gutter tied into the slop collection system. The skid drains will still be piped into the platform slop system and will act as the primary containment for any spills.

The pump is installed and commissioned without incident. However, there is a delay in arrival of the piping necessary for completion of the connection of the skid drains. As the deck plate gutter drains have been connected and are in service, it is decided that this is not sufficient reason to delay placing the pump on standby status. It is noted that the existing pump has not encountered any recent problems and it is not anticipated the new pump will need to be run prior to completion of the drain system. The skid drain system is isolated and the new pump is placed on line in the standby mode.

Several weeks later, the original pump starts to show increasing vibration levels for the in-board bearing. A new shift with a new supervisor had come on to the platform several days before and they were aware that there was now a standby pump available for this service. However, the change-over record indicated that the drain system on the new pump skid was still not complete but that drain was isolated and the deck gutter drain was in service. The shift supervisor orders that the isolation of the skid drain be confirmed, the gutter drains on the new deck checked for leaks, and the new pump brought on line and the old pump shut down for maintenance.

The next day, a sheen is observed on the water surface tailing away from the platform with the current. A search for the cause of the sheen is immediately begun and it is found that there is a leak on the packing of the new crude transfer pump.
Crude has filled the skid containment and has started to overflow onto the decking and into the gutter. Investigation of the gutter drains confirms that the sheen did not originate from this system. Since the packing leak is still quite small, it is left for Maintenance to repair and the search for source of the leak is continued. On further investigation, it is found that the source of the discharge was a cleaning operation on a lower deck. Over-spray from a high-pressure steam cleaner had sent a small amount of cleaning solution over the gutter drain and off the platform. The volume of crude released from the packing and collected by the gutter drains is estimated to be approximately five barrels.

The packing on the new pump is adjusted and the leak stopped. Because the old pump has been dismantled for repair and cannot be returned to service, the new pump is left in operation. The shift supervisor orders the operators to check the new pump packing every six hours to ensure that if there are any further leaks, and the pump skid containment system will not be over-filled again.

Several days later there have been no new packing leaks and the shift supervisor orders that the new pump packing is checked for leaks once a day. The old pump is still out of service awaiting the arrival of spare parts.

Early the following day, the operators check the pump packing and find no leaks. Several hours later a manufacturing flaw in the outboard bearing of the new pump begins to manifest itself and the pump begins to vibrate severely. Within minutes, the packing begins to leak and crude starts to fill the containment structure of the skid. The pump vibration steadily increases until the suction flange of the pump, already under stress from a slight misalignment of the inlet piping, fractures near the pump casing. Crude begins to leak from the crack at a high rate. The skid containment system, already almost full from the progressively worsening packing leak, overflows and crude starts to spill onto the deck and into the gutter drains.
Pressure in the shipping vessel feeding the transfer pumps starts to drop rapidly and the low-pressure alarm sounds in the control room. Operators are dispatched to determine the cause of the pressure decrease. The system pressure continues to drop and the low-low pressure shutdown system shuts in the platform. The transfer pump is stopped automatically on shutdown of the platform. However, there is still a level in the vessel and it is partially pressurized. Vibration of the pump prior to its shutdown had opened the casing crack to 50 percent of the inlet circumference, and crude spills from the pump at an increased rate.

On their arrival at the shipping vessel, the operators observe crude coming from the transfer pump and immediately close the suction and discharge valves. The leak slows and stops. The control room operator reports that the pressure in the system has stabilized. The operators at the pumps note that crude has overflowed the skid containment, but the gutter drains have collected all the flow and no crude has spilled off the platform. They request that the control room operator advise the supervisor of the pump failure and the crude release. They also request that a cleanup crew be sent to the pump area and that the level in the slop vessel be checked to see if clean up can start immediately or if it will have to wait until a safe level is obtained in the slop vessel. One operator will remain onsite to inform the cleanup crew of the slop vessel status while the other operators continue to look for possible secondary leaks and ensure that the system is completely isolated.

Total crude released by the pump failure is estimated at 100 barrels. Total crude release from both the packing leak and the failure, is 105 barrels. Total crude spilled off the platform by the pump problems is 0 barrels.
CHAPTER 3
Subsea Pipelines

3.1 Introduction

3.2 Corrosion Control

3.3 Inspection

3.4 Scenarios
CHAPTER 3

SUBSEA PIPELINES

3.1. INTRODUCTION

Pipelines are strategic assets designed, constructed, tested, operated and maintained to well-established standards. However, during service, pipelines can fail, thus causing an oil spill. Factors affecting pipeline integrity are:

- Loss of support due to seafloor erosion
- Material thinning and perforation due to corrosion
- Bending and deformation due to ship anchor entanglement with pipeline
- Pipe rupture due to overpressuring
- Physical damage by dropping objects

Hence, to preserve pipeline integrity, an effective Inspection and Maintenance program must be put in-place to promptly identify problems.

To introduce an acceptable inspection strategy, the following factors should be considered:

- Government legislation
- Safety requirement
- Operational constraints
- Industrial practice
- Historical data
- Economics

Based on the above factors, the inspection extent and frequency for each pipeline can be defined. In determining the inspection priority / frequency, a risk-based approach may be implemented. The approach is a method widely used by the industry for prioritizing and managing the inspection of offshore structures. The extent of inspection may differ from one pipeline to another based on the condition of the pipeline as assessed by previous inspections (Historical Data).
CHAPTER 3

SUBSEA PIPELINES

3.1. INTRODUCTION

Pipelines are strategic assets designed, constructed, tested, operated and maintained to well-established standards. However, during service, pipelines can fail, thus causing an oil spill.

Factors affecting pipeline integrity are:
- Loss of support due to seafloor erosion
- Material thinning and perforation due to corrosion
- Bending and deformation due to ship anchor entanglement with pipeline
- Pipe rupture due to over pressuring
- Physical damage by dropping objects

Hence, to preserve pipeline integrity, an effective Inspection and Maintenance program must be put in-place to promptly identify problems.

To introduce an acceptable inspection strategy, the following factors should be considered:
- Government legislation
- Safety requirement
- Operational constrains
- Industrial practice
- Historical data
- Economics

Based on the above factors, the inspection extent and frequency for each pipeline can be defined. In determining the inspection priority / frequency, a risk-based approach may be implemented. The approach is a method widely used by the industry for prioritizing and managing the inspection of offshore structures. The extent of inspection may differ from one pipeline to another based on the condition of the pipeline as assessed by previous inspections (Historical Data).
3.2. CORROSION CONTROL

Corrosion of steel pipelines either exposed in the atmosphere, soils, brackish water, seawater and crude production fluids, is produced by an electrochemical process. The generation of anodic and cathodic sites on the external and/or internal surface(s) of the pipeline and the resultant passage of direct electrical current between these areas cause the electrochemical process. To prevent corrosion implementation of the following control methods are recommended:

3.2.1. Design parameters

At the conceptual design and later during detailed design, consultation with the Inspection and Corrosion Division is made to select the appropriate pipeline’s materials, the cathodic protection requirements, the suitable coating system that satisfies the sea characteristics and the inspection and quality program of the entire project.

Aspects of quality assurance (QA) and quality control (QC) are detailed in each contract document at an early stage. Manufacturers of pipes and applicators of coatings or internal linings are normally required to submit Quality Plans and Inspection & Test Plans for Company’s approval prior to the start of the works. Third parties (inspection agencies) are normally employed to undertake the inspection activities at the mills to assure the quality and full compliance with the technical specifications. Similar QA/QC requirements are also detailed for all site construction, including welding, inspection, NDT examinations, gauging, cleaning, pressure testing, etc.

For crude oil, corrosion allowance of 3.0mm is normally added to the design wall thickness of the carbon steel pipelines. The design wall thickness is calculated based on the applicable code (ASME-B31.4 or B31.8) taking into consideration the impact of various stresses.
3.2.2. External corrosion control
Subsea pipelines are externally protected against corrosion by a combination of coatings and cathodic protection.

3.2.2.1. Coating
- Apply primer and two coats of enamel from the same manufacturer. Use coal tar coating in accordance with ANSI/AWWA C203 standard or BS STD 4164/80, 120/5 with properties suitable for tropical climates.
- Sufficient bare pipe at each end of the pipe joint shall be left without any coating in order to permit field-joint welding of two pipe joints.
- When coated pipe has been cooled to ambient temperature and inspected, it shall be moved to concrete coating machine.
- If the coal tar enamel coated pipe joints need to be stored, the outer surface shall be given a water-resistant white wash or craft paper finish coat following final inspection, as per ANSI/AWWA C203.
- For concrete coating, use Portland cement to conform to ASTM standard C-150, and sand to conform to ASTM C-33-66. Mix and grade to meet the required concrete density and strength, while remaining suitable for the coating contractor’s impingement application. Reinforced steel to be galvanized wire mesh to conform to ASTM Standards A615-74 or A82E enforced.

3.2.2.2. Cathodic protection:
Application normally follows an in-house “Engineering Specification” that adheres to NACE and BSI international cathodic protection recommendations and criteria existing and new facilities. The main guidelines are:
- A potential of at least -900 mV vs. Ag/AgCl (sat) (-850 mV vs. Cu/CuSO4 (sat.)) with cathodic protection applied.
- Protection potential value of at least -900 mV vs. Ag/AgCl (sat) (-850 mV vs. Cu/CuSO4 (sat.)), instantaneous OFF (IR drop).
Design current density is 0.5 mA/m² assuming the pipe is externally coated.
The cathodic protection system is designed for a lifetime of 20 years.

3.2.3. Internal corrosion control
The following is the recommended best practice for controlling internal corrosion in pipelines:

3.2.3.1. Corrosion prevention
The following are some preventive measures taken against corrosion:

- **Design**
  As the sea bottom dictates the profile of the line there is little that can be done to eliminate areas of water hold up. Sizing the line to provide fluid velocities of at least 3 ft/sec can prove useful in carrying or picking up free water in certain crude oils.

  Provision for cleaning and instrument inspection are probably the most significant positive actions that can be incorporated into the design of a pipeline. With proper launchers, receivers, bends and the necessary auxiliary equipment, control over corrosion is much more readily achieved.

- **Material selection**
  In many cases for pipelines handling production fluids, proper material selections may be the first choice in the combat against corrosion. However, in some of the more corrosive environments, corrosion control through material selection alone, may prove very expensive due to the cost of superalloy materials.

- **Pipeline internal coating**
  If carbon steel are exposed to corrosive fluids, barrier coatings and linings may be applied. Shop applied epoxy and coal tar epoxy coatings are mainly used. Methods of joining internally coated sections include flanges or mechanical couplings. For larger diameter lines, it may be possible to join the pipe
sections by welding, with additional coating subsequently applied internally over the weld area.

- **Chemical treatment**
  Injection of corrosion inhibitors has proven to be effective for controlling corrosion. Organizations can pro-actively program some in-house pilot testing to evaluate different promising chemicals for field pipelines. For these applications, commercial suppliers can be qualified throughout pre-selective laboratory testing followed by field tests using corrosion coupons and probes. It may be cost effective to install automatic continuous data gathering field-installed loggers. This equipment is installed to make a real time evaluation of corrosion rates and to provide a mechanism for optimization of inhibitor injection rates.

- **Solids removal**
  Pigging for combating internal corrosion can be used, particularly for crude, gas and condensate pipelines. Routine running of cleaning and swabbing pigs has proven to be beneficial in removing the free water and debris that accumulate at low points along the route of the pipeline.

### 3.2.3.2. Corrosion monitoring

Corrosion monitoring is considered as the application of a range of procedures by which corrosion can be measured as it occurs.

Corrosion monitoring in pipelines is utilized mainly to:

- Monitor system for the need of a corrosion treatment program
- Evaluate corrosion rates and/or performance of inhibitors
- Optimization of inhibitor dosage
- Study the effect of fluid parameters on corrosion.

Corrosion coupons, UT readings, corrosion meters, and in some cases applications of real time evaluation of corrosion rates and optimization of inhibitor’s dosage injection, can be utilized to monitor corrosion. Corrosion coupons and probes installed in pipelines are typically the intrusive, retrievable type.
obtain more detailed corrosion data, probes may be connected to automatic, continuous data acquisition instruments.

A software database is utilized to improve the organization, control and analysis of corrosion data. The database should provide information on: pipeline material, location and number of monitoring stations with their circumferential location on the pipe, type of monitoring technique used, and the equipment manufacturer. The database should also be able to incorporate information on pipeline failures and to integrate data obtained from data loggers for analysis and graphical display. The database should, at least, be able to generate reports that provide corrosion rates, graphical analysis, and schedules for installation and retrieval of corrosion coupons and probes.

For subsea pipelines this technology can be applied in the submerged condition. For subsea conditions there is technology available, known as Field Signature Method (FSM) that provides real-time monitoring.

3.3. INSPECTION

The following are the recommended inspection details for both external and internal of subsea pipelines. The external inspection covers from SDV to SDV and the internal inspection covers from launcher to receiver.

3.3.1. Pipeline internal inspection

Operating companies should not entirely depend on non-destructive testing and hydrostatic pressure testing to assess the integrity of their pipelines. Hydrostatic testing is costly, time consuming and provides only pass or fail information at the time of the test, and cannot provide any useful data for future planning.

On-line inspection can be introduced for pipeline condition determination. Magnetic flux leakage (MFL) or Ultrasonic (UT) technologies can be used to identify areas of metal loss for repair or replacement. MFL inspections may make use of either standard or the high-resolution tools. It should be noted that if standard resolution tools are utilized, additional costs may be incurred in verifying several log indications so that the log may be accurately graded.

Pig trap stations should be provided for every hydrocarbon pipeline. Pipelines should also be designed so that all types of pigs can travel without obstructions through valves, fittings, and bends.

Certain arrangements and requirements are generally specified for the piggable pipelines:

- Bend radii should not be less than 3D (D is the nominal pipeline diameter) for line sizes of 18 inches and large, and 5D for lines less than 18 inches.
- Branch connections that are more than 40% of the main line size are to be barred to avoid tool lodging.
- All mainline valves shall be of the full-bore type to allow passage of the pigs.
- Tees should have internal diameters equal to internal diameter of the pipeline.
- Pig indicators should be provided at each trap and at each line isolation valve pit.
- Lifting equipment, such as, monorails with chain blocks should be provided at each trap.
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3.3.2. Pipeline External Inspection

Abbreviations used within the following text are defined as follows:

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Definition</th>
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<tbody>
<tr>
<td>EX</td>
<td>Exposure</td>
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<tr>
<td>SP</td>
<td>Span</td>
</tr>
<tr>
<td>FP</td>
<td>Foot Post</td>
</tr>
<tr>
<td>ROV</td>
<td>Remote Operated Vehicle</td>
</tr>
<tr>
<td>CP</td>
<td>Cathodic Protection</td>
</tr>
<tr>
<td>MSL</td>
<td>Mean Sea Level</td>
</tr>
<tr>
<td>CTC</td>
<td>Cell to Cell Probe for CP Reading</td>
</tr>
<tr>
<td>DP</td>
<td>Dynamic Positioned Vessel</td>
</tr>
<tr>
<td>MV</td>
<td>Milli Volts</td>
</tr>
</tbody>
</table>

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3.3.2.1. Scope of Work
Work includes requirements for:

- CP Survey obtaining potential readings at anodes, areas of coating damage, pipeline crossings, and other significant findings
- Visual Survey and video recording of entire pipeline using ROV, divers and side scan sonar
- Plotting actual pipeline and feature locations

3.3.2.2. CP Survey
This survey is normally completed in conjunction with the visual survey.

The objectives of the CP survey are to:

- Investigate potential levels of the pipelines, anodes, areas of coating damage and pipeline crossings.
- Identify the location of items of debris which could affect the pipeline, by interfacing with the CP system.
- Determine the condition and life expectancy of all anodes.
- Collect data to allow comparisons with historical and future information.
- In general, one of the following systems are installed on ROV and support vessel:
  - CP survey system with remote half-cell towed behind the ship.
  - CP survey system with remote half-cell connected to the ROV umbilical.
- It is imperative that a suitable data communication and video links between Pilot Cabin and CP Workstation are provided
- The CP survey shall be:
  Continuous over both exposed and buried pipeline sections. Particular efforts should be made to distinguish between individual lines. Where damaged anodes and coating are suspected, video may be used to assist interpretation of CP Data.
ROV survey will be carried out:
In a manner to minimize CP survey error and at a distance from the pipeline as specified by CP engineers. The ROV shall fly directly above pipeline being surveyed. Where the ROV has to move off the top of the line (e.g. to survey crossing supports) a separate run with the ROV flying directly above the pipeline shall be made to record the CP data.

CP stab readings will be required as follows:
On short lines (less than 5000 ft.) at least two readings per pipeline. The first reading shall be as close as possible to the start of the survey (e.g. on the first anode located). If at the end of the line a second reading has not been taken the ROV shall backtrack to the last recorded anode to take the second CP reading.
On long lines at least every 5,000 ft, and more frequently where the line potential changes by more than 50 mV in 5000 ft.
Additionally, readings are required at each area of major coating damage where bare metal is exposed and at flanges or flange shrouds.
Pre and post dive calibrations shall be performed with a “Reference Electrode Calibration” unit.

3.3.2.3. Visual Survey
The objectives of the visual survey are to determine the following:
- Attitude and position of the pipeline
- Areas of seabed instability
- The degree of pipeline exposure
- The extent of burial
- The location of items of debris which could affect the pipeline
- The nature and extent of damage to or defects in the pipeline and it’s coating
- To provide information for comparison with or verification of other forms of survey data, e.g. side scan sonar
- Any changes in pipeline position
The survey data must be recorded as both commentary and as information in an online data entry system:

- **Crossings:**
  General condition of the crossing pipelines, as well as span lengths, coating damage, the condition of each support, angle or crossing, and whether or not the two lines are touching. Sufficient data shall be recorded to produce crossing drawings.

- **Inspection Items:**
  General conditions of inspected items such as flanges, valves, tees, etc.

- **Coating Damage:**
  Description and dimension of the weight coat damage and bare metal exposure.

- **Free Spans:**
  Lengths to be measured relative to starting FP location; heights can be estimated visually. For lines of 30” diameter and larger because of problems of checking for seabed contact whilst flying over the top of the line (for good CP readings) two survey shall be run. The first survey shall be run over the top of the line recording CP readings and all other visual data. The second survey shall be run along the side of the line, checking for spans and recording any other visual information. Both surveys shall be run in ascending FP direction. During the onboard processing, checks shall be made that the navigation data for the two surveys is consistent.

- **Exposure:**
  Use “Innovatum” or similar profiling system to identify pipelines exposure/spanning/burial.

- **Debris:**
  Describe major debris, note position relative to pipeline, whether any damage has been caused, and estimate dimension for debris. Report if the found debris is “pulling” current from the pipeline system.
- **Anode Survey:**
  Note condition, percentage depletion, anode type, and CP stab reading.

- **Supporting Structures:**
  Describe type of support (e.g. grout bag, sleeper, temporary support, etc.), supported event (span, crossing or riser), position of supported event (span start FP, crossing point FP, riser elbow FP), contact between the pipeline and the support, and the height of the support. Describe stabilization mats in a similar manner.

- **Physical Damage:**
  General condition of dents, bends, leakage, etc. is to be noted.

- **Riser survey (by divers):**
  All risers shall be inspected from SDV to the riser elbow and out to a distance of 250ft. from the face of the platform. Record distance from bottom of riser bend to sea floor, description of riser coating, water depth at bottom of riser, riser knee brace/riser guard and riser physical damage. UT readings are not required unless the CP readings are more positive than -750 mV.

- **Riser Clamp Survey (by divers):**
  Each riser clamp shall be inspected and if required, it will be water blasted to remove marine growth to facilitate inspection. Record clamp number and location, number of bolts, missing or loose bolts, nut and bolt size, maximum gap between clamp and riser, standoff/gasket damage. Also, record CP readings on both sides of the clamp and report corrosion, if any.

### 3.3.2.4. Reports:
Reports shall include the following:

- Video tapes of approved quality, with simultaneous spoken commentary and written diving log. Dates and time shall be automatically recorded on the video. Location information (FP’s) provided by surveyors, should also be automatically
recorded on video. The FP values shall be updated at least once every 12 seconds.

- Photographs of significant observations.
- CPPR as taken by CP engineers.

3.4. INCIDENT SCENARIOS

3.4.1. Preparing for a pipeline failure and subsequent repair

In addition to safety and economic considerations, a failure in oil pipeline must be dealt with promptly to reduce pollution and its subsequent damage to nature. The following address guidelines to repair subsea oil pipeline leaks.

**Small leak repair**

Repair a small leak with a clamp. The dive crew available in the field can install the clamp. Thus:

- The primary unknown in this scenario is the time required to locate the leak.
- Locate leak by removing weight coating. If a leak occurs in a concrete weight coated pipeline, it may be possible for the leaking liquid to flow between the outer pipe wall and the concrete coating for some distance before the liquid leaks into the water through a weak point or crack in the concrete coating. Concrete coating will have to be removed until the actual site of the leak from the pipe is located. A further complication is that some pipelines are partially or completely buried, and will have to be jetted before weight coating can be removed.
- To reduce down time and pollution, fabricate a temporary clamp locally.
- In a reactivate mode: order a purpose-manufactured clamp to replace the temporary clamp.

In a proactive mode, lead-time would be shortened by either having purchased a clamp (or an inventory of clamps of different sizes) previously, or having joined an organization that supplies from inventory on short notice.
Large leak repair
A large leak, or relatively short section (< 1000 ft.) damaged or extensively corroded pipeline would be repaired by replacing a section of line with one or more flanged spool pieces, each about 80ft. long (a small work- barge or a large crane equipped boat can be used).
The primary unknown is barge availability.
- Install pipeline repair connectors with misalignment/swivel flanges on the spool pieces at each end.
- Flush pipeline with water before repairing.
- Mobilise the barge to the field
- Cut the line and remove the damaged section.
- Install flanges on the existing pipeline on the remaining line at each end of the cut.
- Install spool pieces.
In a reactive mode, pipeline repair connectors would have to be ordered. If the pipeline had to be out of service for that length of time, it is possible that mobilizing a lay barge to make the repair would reduce that downtime. The lay barge would cut the line, allowing flanges to be welded on each end eliminating the need for the connectors.
In a proactive mode, the long lead-time or the requirement for a lay barge would be eliminated by:
- either having purchased a set of connectors (or an inventory of connectors of different sizes) previously, or
- having joined an organization that supplies connectors from inventory on short notice

Replacement of a long (>1000ft.) section of pipeline
A long section of damaged or extensively corroded pipeline would be replaced by a lay barge:

Unknowns for this scenario are barge and pipe availability. Reactive and proactive modes are essentially the same, except that availability of a lay barge and replacement pipe would be much less of a concern with proactive planning.
- Flush pipeline with water before the repair is made.
Mobilise the barge.
Cut the section of pipeline to be removed and replaced.
At one end of the cut, dewater a section of the original line.
The barge would then pick up the line, and normal pipelay operations would ensue attaching replacement pipe to the original.
Weld on a swivel flange at the end of the replacement section.
Lift the other end of the original line and weld on a flange.
Lower that section and complete the operation by making up the flanged connection.

Alternatively, a pipeline repair connector if available, could be used, eliminating the need for the second dewatering and pick up operation. This option, however, would likely be more costly.

While replacement of the line was taking place, a pig receiver would be fabricated and installed at the outlet end of the pipeline. When the line was returned to service, dewatering pig(s) would be displaced to the receiver.

3.4.2. Repairing non-conforming pipeline crossings and spans on existing lines

During pipeline surveys, non-conforming conditions may be observed that require remedial action to preserve the structural integrity of the pipelines. These conditions may include: loss of supports, supports found inactive due to soil erosion or support settlement, and pipeline movement off the support due to significant vibration of the supported pipeline or storm action. The following guideline is a recommended for the design and installation of the supports at non-confirming spans and crossings.

General design requirement

The pipeline shall be supported using fabric-form grout bags specifically designed for supporting offshore pipelines. The supports must be pyramid shaped with an integral base. This ensures that the weight and load is distributed to the seabed uniformly over the entire base area. Supports shall be designed with the consideration of the appropriate soil bearing capacity. Supports must be positioned such that the span length, measured
from centre of support to centre of support or to the point of touch down, is less than the maximum allowable span length (MASL) given for each pipeline.

**Pipeline maximum allowable span calculation**
The maximum allowable span lengths are calculated using a Marine span analysis program. The pipeline variables required for this calculation are: outside diameter, wall thickness, corrosion coating thickness and type, weight coat thickness and density, line service (oil, water or gas) and the worst case orientation of the line. The largest force will be on lines oriented at 90° to the direction of the most significant storm; the smallest force will be on lines oriented parallel to this direction.

**Induced soil bearing stress**
In the design of the crossing/span, for each support, calculate the induced soil bearing stress under each support due to:
- The submerged weight of pipe length being supported including water + coating
- The filled grout bag
  The sum of these loads divided by the support area is the induced soil bearing stress. The induced soil bearing stress shall be less than the soil bearing capacity for that area. For the purpose of this calculation the pipeline shall be considered full of water.

**Existing inactive supports**
For crossing/span repairs, previous inactive supports shall not be:
- used as a base for new supports
- moved to position the new supports, unless absolutely necessary
- removed on completion of the repair

**For adequate pipeline supporting**
- aim to locate the supports directly under the pipeline
- ensure that the maximum offset of the support is less than one quarter of the pipeline outside diameter e.g. 6 inches for a 24 inch line
- ensure that supports are within 5° from the vertical
Special requirements for supporting crossings
Crossings can be broken down into two general types:
Conventional crossings – with the top line raised off the bottom line to give a gap between the pipelines.
Hard crossings – where the top line is only raised up, to put a chaffing mat between the two pipelines. The designer will determine which type of crossing is applicable on a case by case basis.
For conventional crossings, where upper line is raised, the following practice is recommended:
❖ The resultant separation of the line shall be 6 inches.
❖ The upper pipeline shall be supported on one central support, with additional supports out to the points of touchdown as required by design.
❖ The design separation between the central support and the lower pipeline shall be 10 feet. This is to accommodate acute angle crossings where the central support cannot be located close to the crossing point. In the field the central support shall be located within 1 to 10 feet from the lower pipeline. This flexibility allows the minimum number of supports used.
For hard crossing installation, the designer shall run the structural integrity analysis for both top and bottom pipelines. For each pipeline, the following information will be required:
❖ Outside diameter
❖ Line pipe wall thickness
❖ Thickness of corrosion coating
❖ Density of corrosion coating
❖ Thickness of concrete weight coat
❖ Density of concrete weight coat
❖ Grade of steel
The following practice is recommended:
❖ The top pipeline shall be raised a maximum of 2 inches to install a neoprene isolation mat between the two pipelines.
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- Thickness of corrosion coating
- Density of corrosion coating
- Thickness of concrete weight coat
- Density of concrete weight coat
- Grade of steel

The following practice is recommended:
- The top pipeline shall be raised a maximum of 2 inches to install a neoprene isolation mat between the two pipelines.
- The crossing point shall be considered as a support for the top pipeline. Additional supports shall be installed out to the point of touchdown as required by design.

Work procedures

Prior to work commencement, prepare procedure to cover:
- description of all grouting equipment
- recipe for the grout
- mixing times
- surface to seabed grout hose sizes
- range of sizes of bags to be used
- pumping times for each type of grouting
- setting times
- cleaning procedure for grouting equipment

Use any of the following lifting mechanism to raise the upper pipeline for rebuilding crossings:
- air bag
- jacking bag
- “A” frame
- crane with two leg nylon straps

As-built drawings shall be produced offshore showing:
- Accurate distances between adjacent supports and between supports and points of touch down.
- The state of burial of the lower pipeline at the crossing point.
- The final separation of the lines (where appropriate).
- The bearing of each line.
- The foot posts of each item crossing, support, and point of touchdown.
- The types of grout bags and size of all mud mats used, and their heights when installed.
- Description and dimensions of any items of debris located in the vicinity.
- Any item that affected the height of bag installed or length of overall span e.g. free spans at expected touchdown point.
3.4.3. Pipeline anode retrofit

Periodically a detailed review of the pipeline CP system must be carried out to ensure that pipeline is protected externally from corrosion. If the pipeline CP system is found to be not performing satisfactorily then new anodes must be added in areas without adequate protection. Commercially and technically proven retrofitting techniques must be used. A design using large anodes spacing would help reduce installation cost. Premature depletion of pipeline anodes system may be due to a number of factors including:

- Under design
- Coating damage/field joint damage
- Time in service
- Debris
- Interaction of pipeline and platform CP system in absence of isolation joint between pipelines and risers. With careful planning this same interaction can be used to reduce anode-retrofitting costs on pipelines by drawing some current from the platform CP system.

The following method is recommended for pipeline anode retrofit:

The anode sled (string of anodes) is placed on the seabed by the pipeline and connected to the line via a cable. One end of an armoured electrical cable (~20 ft.) is welded to the anode sled and the other is bolted to a clamp which in turn is installed on the pipeline at a field joint so that only mastic has to be removed to expose pipeline steel:

- Pre-installation CP readings are to be made on the clean pipe prior to the installation of the clamp
- Post installation readings are made on each of anode, sled, bolts, and if possible the pipe

All CP readings are recorded. A video of the installed assembly with the simultaneous spoken commentary is prepared. The exact location of the anode retrofit clamp on the pipeline, in UTM coordinates, is recorded.
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DEFINITIONS

Anode
The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter the solution at the anode. Also used as a shortened form for galvanic or sacrificial anode.

Cathodic protection
A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Corrosion
The deterioration of a material, usually a metal, which results from a reaction with its environment.

Free span
A length of pipeline with no support along that length except at either end.

Galvanic anode
A metal that provides sacrificial protection to another metal that is more noble when electrically coupled in an electrolyte. This type of anode is the current source in one type of cathodic protection.

Impressed current
An electric current supplied by a device employing a power source that is external to the electrode system. (An example is direct current for cathodic protection.)

Jacket
The structural assembly providing support for one or more wells. May also be called a platform.

Jack up rig
A barge-like, floating platform with legs at each corner that platform above the water. Towed to location offshore, the
DEFINITIONS

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The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter the solution at the anode. Also used as a shortened form for galvanic or sacrificial anode.

Cathodic protection
A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Corrosion
The deterioration of a material, usually a metal, which results from a reaction with its environment.

Free span
A length of pipeline with no support along that length except at either end.

Galvanic anode
A metal that provides sacrificial protection to another metal that is more noble when electrically coupled in an electrolyte. This type of anode is the current source in one type of cathodic protection.

Impressed current
An electric current supplied by a device employing a power source that is external to the electrode system. (An example is direct current for cathodic protection.)

Jacket
The structural assembly providing support for one or more wells. May also be called a platform.

Jack up rig
A barge-like, floating platform with legs at each corner that can be lowered to the sea bottom to raise or “jack up” the platform above the water. Towed to location offshore, the
legs of the jack up rig are in a raised position, ticking up high above the platform. When on location, the legs are run down hydraulically or by individual electric motors.

Joint
Any single weld joining one brace to another or to a leg of a jacket or other structure.

Node
Any combination of braces joining a leg, or each other, forming a cluster. This typically consists of one or more joints.

Remote wells
Offshore oil producing wells on a jacket or platform. Synonyms single well platform, two well platform, four well platform, six well platform, and production well platform.

Sacrificial anode
See Galvanic anode.

Satellite platform
Offshore platforms for facilities other than well-heads. Synonyms: Gas Oil Separation Plant (GOSP), separation platform, compression platform, injection platform, tie-in platform.

Wellhead
An assembly of valves mounted on the casing through which a well is produced. The valve assembly also allows the well to be shut in safely when necessary, and may contain additional valves for testing.

Workover
Operations on a producing well conducted to restore or increase production.

Workover barge / rig
A barge or rig equipped to perform workover operations.

Xmas tree
Synonym for wellhead. See Wellhead.
APPENDIX 2
CLEAN-UP AND RE-INJECTION SYSTEMS
A2.1. Well Clean-up Overview

A2.1.1. Clean-up Strategy

At the start of production in most oil fields, water production is almost nil. As the fields mature, water production and water injection breakthrough problems are typically experienced. In order to remove the skin damage caused by drilling, killing or completion operations, different matrix acidizing techniques with different volumes of 15% HCI (50, 40 USG/ft. of perforation and 25, 20, 15, 10 USG/ft. of horizontal hole) were implemented. The acid is either bull headed from the surface or through the coiled tubing, depending on the injection rate. In the case of low pressure reservoirs, the completion, most of the times incorporates Electrical Submersible Pumps (ESP) or other types of artificial lift equipment. In these wells, acidizing is always conducted before running completion in the hole to protect the downhole equipment from corrosive acids.

The well is opened for clean-up on the maximum possible choke size till Basic or Bottom Sediment and Water (BS&W) becomes less than 1% & pH <6 standard wells. As for wells which have experienced fluid losses and/or water breakthrough, clean-up would continue till minimum BS&W is attained and pH becomes <6 for at least three consecutive hours.

A2.1.2. Development of Burner Heads:

Different service companies introduced the first flaring systems. Today, different types of burners are available to burn oil, diesel and emulsion. They are usually comprised of one or more burning heads mounted on a boom to keep them at a safe distance from the rig.

- **Atomiser:**
  The atomiser is the heart of a burner system. It consists of a chamber where the oil and air are combined before the mixture is ignited by a pilot light.

- **Increased Burner Efficiency:**
  Much of the pollution and visual impact on the environment arise from inefficient burning—regularly seen in the fields with large black plumes of smoke coming from rigs during operations.
A2.1. Well Clean-up Overview

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A2.1.2. Development of Burner Heads:
Different service companies introduced the first flaring systems, in the late 1960’s. The systems burnt oil safely and efficiently. Today, different types of burners are available to burn oil, diesel and emulsion. They are usually comprised of one or more burning heads mounted on a boom to keep them at a safe distance from the rig.

- **Atomiser:**
  The atomiser is the heart of a burner system. It consists of a chamber where the oil and air are combined before the mixture is ignited by a pilot light.

- **Increased Burner Efficiency:**
  Much of the pollution and visual impact on the environment arise from inefficient burning – as regularly seen in the fields with large black plumes of smoke coming from rigs during
cleanup operations. Increasing burner efficiency by introducing ‘Green Burners’ will greatly reduce these plumes of smoke as well as provide complete combustion of products such as H2S, SO2 into potentially less harmful substances.

One potential downside from the use of ‘Green Burners’ is the increased heat radiation associated with improved efficiency. To combat this situation it may require an upgrade on the rig water cooling spray system. Increasing the length of the burner boom to reduce radiation effects is another practical factor that is limited by the structural design of the boom and the rig.

A2.2. Oil Re-injection System

Oil re-injection systems have been introduced into several offshore fields. The equipment and re-injection procedure being used may differ slightly between fields and the information provided below is for illustration only.

A2.2.1. Equipment for Offshore Operation

The re-injection system for offshore operation typically consists of the following:

<table>
<thead>
<tr>
<th>No.</th>
<th>Item Name</th>
<th>Dimensions (feet)</th>
<th>Working pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1)</td>
<td>Choke Manifold</td>
<td>(6’ X 6’ X 3’)</td>
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</tr>
<tr>
<td>2)</td>
<td>Eruption Manifold</td>
<td>(6’ X 5’ X 3’)</td>
<td>/ 5000</td>
</tr>
<tr>
<td>3)</td>
<td>Separator</td>
<td>(19’ X 9’ X 7’)</td>
<td>/ 1440, 3 phase</td>
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<td>4)</td>
<td>Oil Manifold</td>
<td>(5’ X 2’ X 1’)</td>
<td>/ 1480 at 100∞F</td>
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<td>Gas Manifold</td>
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<tr>
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<td>Surge Tank</td>
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<td>/ 50</td>
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<tr>
<td></td>
<td></td>
<td>(capacity 70-80- BBLS)</td>
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<tr>
<td>7)</td>
<td>Sundyn Pump</td>
<td>(7’ X 7’ X 5’)</td>
<td>/ 410 (10,000 BOPD)</td>
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<td>8)</td>
<td>ESD Panel</td>
<td>41/2’ X 3’</td>
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</tr>
<tr>
<td>9)</td>
<td>Generator</td>
<td>191/2’ X 8’ X8’</td>
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</tr>
<tr>
<td>10)</td>
<td>Low Gas Metering Skid</td>
<td>(7’ X 3’ X 3’)</td>
<td>/ 1440</td>
</tr>
</tbody>
</table>

Figure A1 shows a typical offshore re-injection system line diagram.
cleanup operations. Increasing burner efficiency by smoke as well as provide complete combustion of products such as H2S, SO2 into potentially less harmful substances. Increased heat radiation associated with improved efficiency. To combat this situation it may require an upgrade on the rig water cooling spray system. Increasing the length of the burner boom to reduce radiation effects is another practical factor that is limited by the structural design of the boom and the rig.

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<th>Item Name</th>
<th>Dimensions (feet)</th>
<th>Working pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1)</td>
<td>Choke Manifold</td>
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<td>2)</td>
<td>Eruption Manifold</td>
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<td>X 5</td>
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<tr>
<td>3)</td>
<td>Separator</td>
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<tr>
<td>4)</td>
<td>Oil Manifold</td>
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<td>(</td>
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<tr>
<td>5)</td>
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<td>6)</td>
<td>Surge Tank</td>
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<tr>
<td>7)</td>
<td>Sundyn Pump</td>
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</tr>
<tr>
<td>8)</td>
<td>ESD Panel</td>
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<td></td>
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<tr>
<td>9)</td>
<td>Generator</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10)</td>
<td>Low Gas Metering Skid</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Figure A1 shows a typical offshore re-injection system line diagram. It is worth mentioning that a complete and detailed hazardous and operability (HAZOP) review has to be conducted on each item of the above system. Third party inspection is a must to make sure that all equipment is rigged-up in properly designated areas and tested as per world-wide standard safety procedures.

A2.2.2. Safety Features

The Emergency Shutdown System is capable of shutting down both the platform and the testing equipment.

A2.3. Clean-up Guidelines for Oil Re-injection System

Different guidelines have been implemented in the RECSO member companies. Highlighted below are two sets of guidelines for two separate fields:

A2.3.1. First Set of Guidelines

- Shut in the well for 4 hours after completing the acid job so that the acid can complete its reaction with the formation rocks.
- Clean-up the well on the maximum choke size possible through the burner and collect samples at the choke manifold every one hour and perform the analysis for BS & W, pH, Ca, Cl and S.G.
- When pH>5, pass the flow through the separator and check the water in the oil for one hour.
- If no water is present, then start the oil injection into the production lines.
- If water still exists, then continue to clean up, meanwhile collect water samples from the separator and inlet line of the production header every one-hour for analysis and tabulate the data. A typical format of table is shown in table 1.
- Ensure that the water pH = 5.5 and composition is close to the produced water (formation or injected water) prior to diverting the flow to the production lines. Please refers to the attached Table A2 pertaining to the water constituents as a reference.
N.B.: Water to be completely drained from the separator after collecting each sample.

- Terminate the clean-up/oil injection operations as soon as the BS & W reaches minimum or < 1% for three consecutive hours.

Figures A1 and A1a represent typical re-injection system line diagrams.

A2.3.2. Second Set of Guidelines

This system is applied to wells completed with Electrical Submersible Pumps (ESP). The guidelines for the system are:

- Backflow the well by N2 lifting through coiled tubing. This is done before running the completion.
- Monitor the flow back fluid properties and when the oil content reaches a trace value, change the line from the flare system to the re-injection system.
- In case the pH value is less than 5.5 inject fresh water from the inlet of the separator for neutralization.
- Separated oil in the separator has to be transferred regularly or continually to the production flow line by injection pump.
- Once the oil content increases to over 5%, the flow back operation will be discontinued.
- Well cleaning after the flow back operation will continue using Electrical Submersible Pump (ESP) to the production flow line after well completion.
- In case of negative flow while lifting with N2 due to low reservoir pressure after an acid job, the ESP will pump out the spent acid to the production flow line after the well completion.
- Usually in case of low reservoir pressure about 400 bbls of the completion fluid is lost in the reservoir during completion time which will neutralize the spent acid in the reservoir. This eliminates the problem of otherwise corrosive spent acid coming in contact with production flow line requiring treatment by injecting fresh water for neutralization.
A2.4. Implementation
An example of the results obtained from the implementation of a re-injection program is shown in Table A3. The total volume of oil and gas burnt, re-injected and water dumped during cleanup operations are indicated in the table. Note that burning was reduced from 100% to 31%.

A2.5. Future Techniques
Future objective is to bring burning down to 0% by introducing new techniques such as:
- Post acid stimulation: Bullhead the well with caustic to neutralize acid in the well prior to flowing back.
- During flow back operation spike caustic into the line upstream of the choke manifold.
- Reduce acid dosage further from the typical 10 USG/ft. of open hole.
- Produce well without stimulation and clean up directly to the flow line.
- Flow acidic returns (oil & water) to a special barge tied up alongside the rig. A schematic of the system using the above techniques is shown in Figure A2.

A2.6. Attachments:
- Re-injection system line diagrams in offshore operation, Figure A1 and Fig A1a.
- Schematic of a re-injection system aimed to achieve 0% emission, Figure A2.
- Typical water analysis sheet for re-injection system, Table A1.
- Chemical analysis guidelines for re-injection system from actual field reports, Table A2.
- Results of implementation of re-injection system for seven offshore wells, Table A3.
SAFETY LINE OVERBOARD
BY PASS
GAS
SURFACE TREE
(PLATFORM)
GATHERING BOAT
PRODUCTION MANIFOLD
GAS
BY PASS
OIL
WATER TO DRAIN
TO FLARE
FRAC WATER INJECTION SYSTEM
CHEMICAL INJECTION SYSTEM
MANIFOLD
FIGURE-A1a
ACIDIZED WELL
DIESEL
OIL
SPENT ACID (PH 2)
WATER
CO₂
CaCl₂
EMULSION
BURN TO CLEAN
FRESH WATER + NOAH
DEMULSIFIER
OIL WATER OIL
SURGE TANK
OIL
REINJECTION
GATHERING BOAT
CLEAN WATER TO SEA
40 TO 20 PPM
DEOILING SYSTEM
SEPARATOR
OIL
PRODUCTION HEADER
S
FIGURE A2
ACIDIZED WELL
DIESEL
OIL
SPENT ACID (PH 2)
WATER
CO₂
CACl₂
EMULSION

FRESH WATER + NOAH
DEMULSIFIER

OIL WATER

SEPARATOR

OIL

SURGE TANK

OIL

REINJECTION
GATHERING BOAT

CLEAN WATER TO SEA
40 TO 20 PPM

DEOILING SYSTEM

PRODUCTION HEADER

FIGURE A2
<table>
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<th>Well No</th>
<th>String Date Time</th>
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</table>

**WATER ANALYSIS FOR OIL RE-INJECTION SYSTEM**

<table>
<thead>
<tr>
<th>TABLE A1</th>
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**Remarks**
## WATER ANALYSIS FOR OIL RE-INJECTION SYSTEM

Rig Name:

Well No:

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<th>String</th>
<th>Date</th>
<th>Time</th>
<th>Sampling Point</th>
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<th>S.G.</th>
<th>PH</th>
<th>CL-Mg/l</th>
<th>Ca++ Mg/l</th>
<th>SO4-Mg/l</th>
<th>Remarks</th>
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<td>C</td>
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<tr>
<td></td>
<td>100000-140000</td>
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<td>135000-145000</td>
<td>158000-160000</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td></td>
<td>400-500</td>
<td>300-400</td>
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<td>400-500</td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

**Sodium Chloride Brine**

<table>
<thead>
<tr>
<th>Constituents (mg/l)</th>
<th>&gt;8.0</th>
<th>550-600</th>
<th>3200-3400</th>
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<tr>
<td>Sea Water</td>
<td>8.2-8.4</td>
<td>1.033</td>
<td>550-600</td>
</tr>
<tr>
<td>Live Acid (15% W/V)</td>
<td>&lt;0-&lt;5</td>
<td>1.075</td>
<td>&lt;10</td>
</tr>
</tbody>
</table>

Values depend on the specific gravity (% w/v Sodium chloride or calcium chloride in each constituent.)
### CHEMICAL ANALYSIS GUIDELINES FOR RE-INJECTION SYSTEM

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<th>Field</th>
<th>Formation</th>
<th>PH</th>
<th>Sp.Gr.</th>
<th>Calcium (mg/l)</th>
<th>Chloride (mg/l)</th>
<th>Sulphate (mg/l)</th>
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<td>**</td>
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<td>Live Acid (15% W/V)</td>
<td>&lt;0-&lt;5</td>
<td>1.075</td>
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APPENDIX 3
FURTHER READING
American Petroleum Institute

API RP 2A Planning, Designing and Constructing Fixed Offshore Platforms

API RP 2G Recommended Practice for Production Facilities on Offshore Structures

API RP 2L Planning, Designing and Constructing Helipads for Fixed Offshore Platforms

API RP 2X Ultrasonic Examination of Offshore Structural Fabrication and Guidelines for Qualification of Ultrasonic Technicians

API RP 14C Basic Surface Safety Systems on Offshore Production Platforms

API RP 14E Design and Installation of Offshore Production Platform Piping Systems

API RP 14G Recommended Practice for Fire Prevention and Control on Open Type Production Platforms

API RP 500B Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms

American Society of Mechanical Engineers

ASME B31.4 Liquid Petroleum Transportation Piping System

ASME B31.8 Gas Transportation and Distribution Piping System

IMCOS Marine Limited, London

IMCOS Weather in the Gulf

Revised - OFFSHORE PRODUCTION-FINAL.indd 130 1/19/15 1:10 AM
American Petroleum Institute

API RP 2A  Planning, Designing and Constructing Fixed Offshore Platforms
API RP 2G  Recommended Practice for Production Facilities on Offshore Structures
API RP 2L  Planning, Designing and Constructing Helipads for Fixed Offshore Platforms
API RP 2X  Ultrasonic Examination of Offshore Structural Fabrication and Guidelines for Qualification of Ultrasonic Technicians
API RP 14C  Basic Surface Safety Systems on Offshore Production Platforms
API RP 14E  Design and Installation of Offshore Production Platform Piping Systems
API RP 14G  Recommended Practice for Fire Prevention and Control on Open Type Production Platforms
API RP 500B  Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms
API RP 1111  Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines

American Society of Mechanical Engineers

ASME B31.4  Liquid Petroleum Transportation Piping System
ASME B31.8  Gas Transportation and Distribution Piping System

IMCOS Marine Limited, London

IMCOS  Weather in the Gulf
International Association of Lighthouse Authorities

IALA  Recommendations for the Marking of Offshore Fixed Structures
IALA  Recommendation for the Notation of Luminous Intensity and Range of Lights
IALA  Recommendation for the Calculation of the Range of a Sound Signal
IALA  Recommendation for a Definition of the Nominal Daytime Range of Maritime Signal Lights Intended for the Guidance of Shipping by Day
IALA  Recommendation for Leading Lights
IALA  Recommendation for the Colours of Light Signals on Aids to Navigation
IALA  Recommendation on the Determination of the Luminous Intensity of a Marine Aid-to-Navigation Light
IALA  Recommendation for the Rhythmic Characters of Lights on Aids to Marine Navigation
IALA  Recommendation for the Surface Colours Used as Visual Signals on Aids to Navigation (Specifications for Ordinary and Fluorescent Colours)
IALA  Recommendation for the Calculation of the Effective Intensity of a Rhythmic Light

National Association of Corrosion Engineers

NACE MR0175  Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment
NACE RP0169  Control of External Corrosion on Underground or Submerged Metallic Piping Systems
NACE RP0176  Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Productions

NACE RP0190  External Protective Coatings for Joints, Fittings, and Valves on Metallic Underground or Submerged Pipelines and Piping Systems

NACE RP0192  Monitoring Corrosion in Oil and Gas Production with Iron Counts

NACE RP0387  Metallurgical and Inspection Requirements for Cast Sacrificial Anodes for Offshore Applications

NACE RP0492  Metallurgical and Inspection Requirements for Offshore Bracelet Anodes

NACE RP0775  Preparation, Installation and Analysis of Corrosion Coupons in Oilfield Operations

NACE TM0194  Field Monitoring of Bacterial Growth in Oilfield Systems

NACE Report 7L192  Cathodic Protection Design Considerations for Deepwater Structures

NACE Report IG194  Splash Zone Maintenance Systems for Marine Steel Structures

Other Sources
