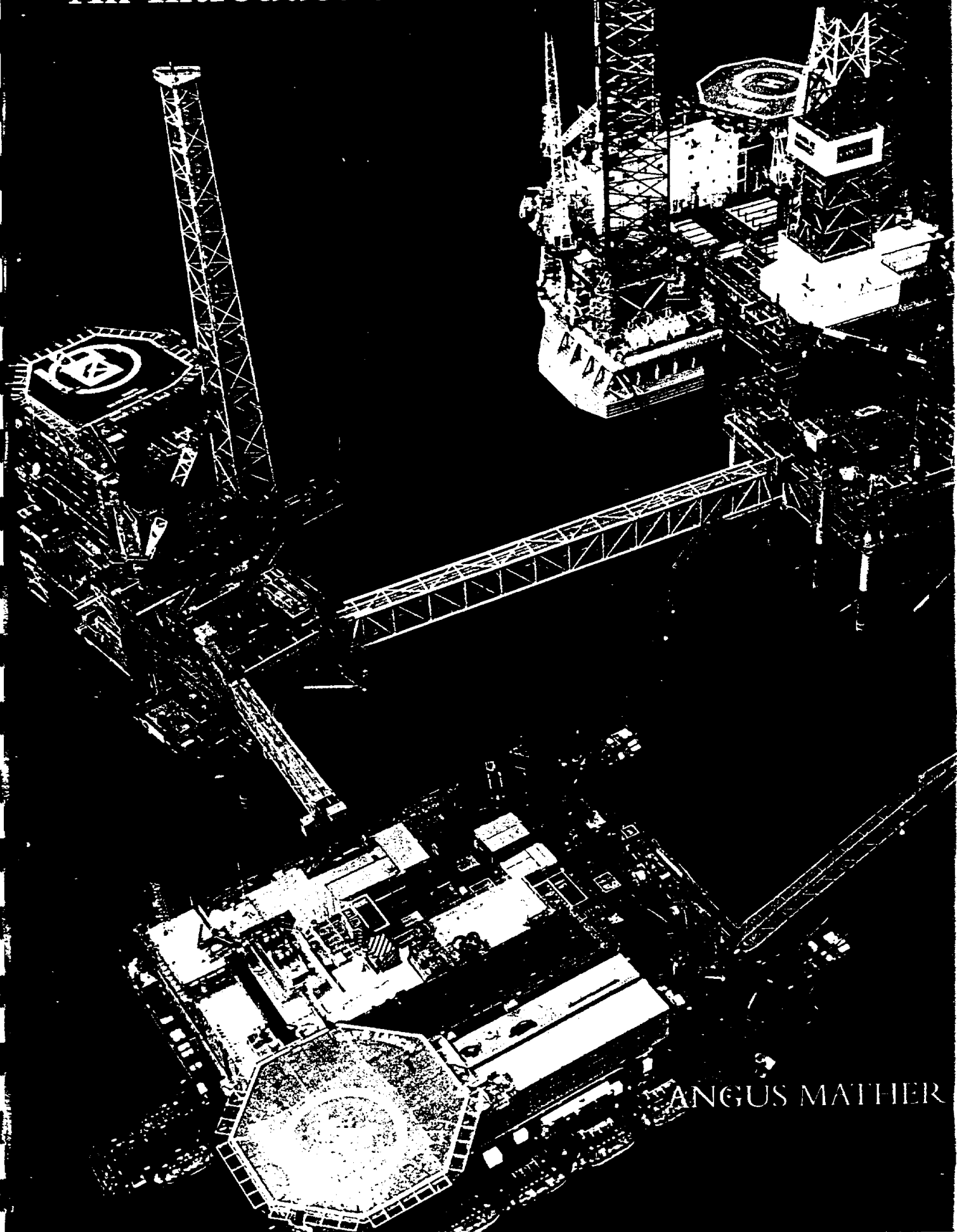


# OFFSHORE ENGINEERING

## An Introduction



ANGUS MATHER

P. KULKARNI

15/07/01

# Offshore Engineering

## An Introduction

By  
Angus Mather

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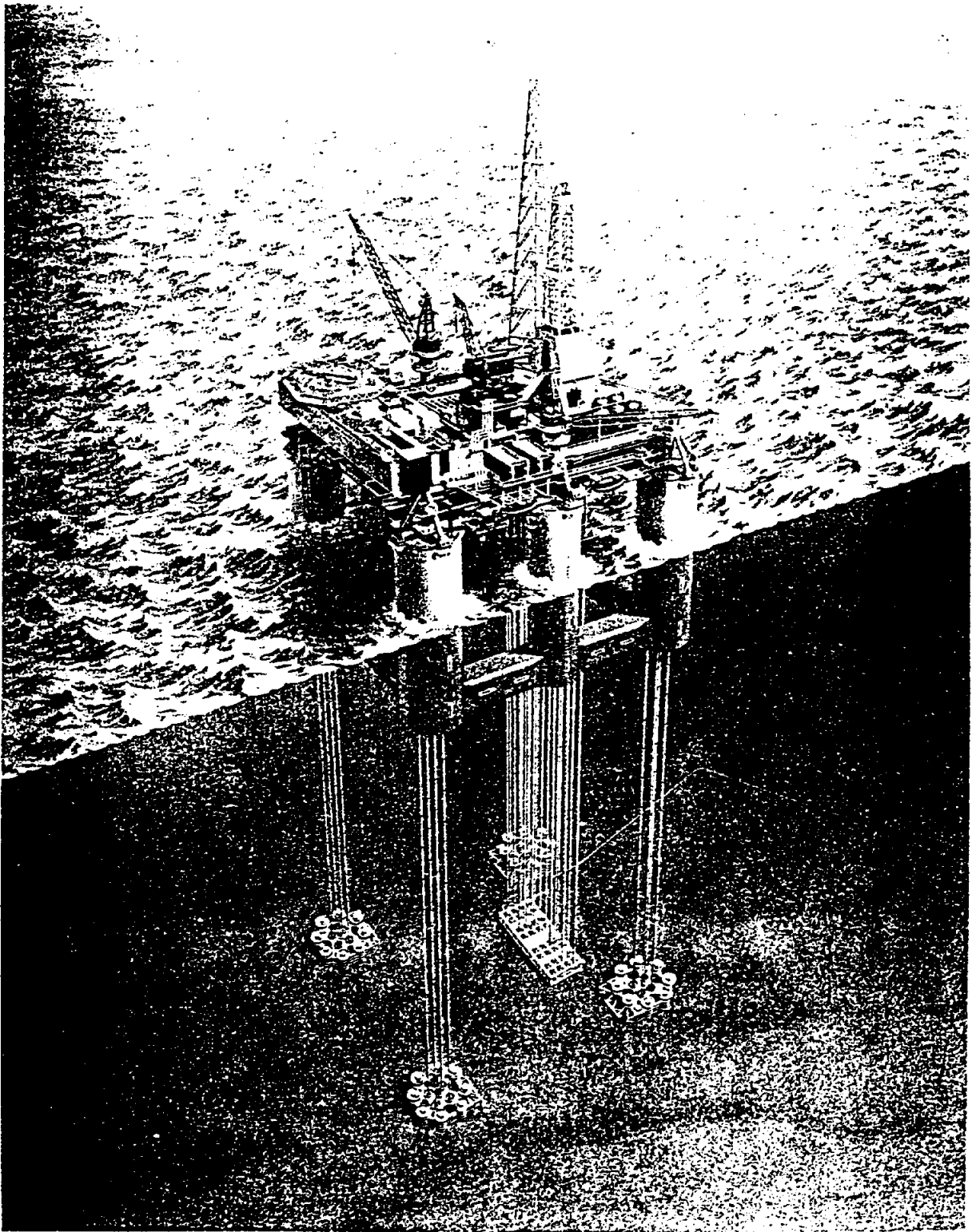
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*Cover - The Shell/Esso 49/19a Clipper installation.  
In attendance the Safe Lancia accommodation support vessel and the Santa Fe Monarch jack-up.*



*Tension Leg Platform (TLP), the Cenozo Hutton  
now owned by Oryx.*



## FOREWORD

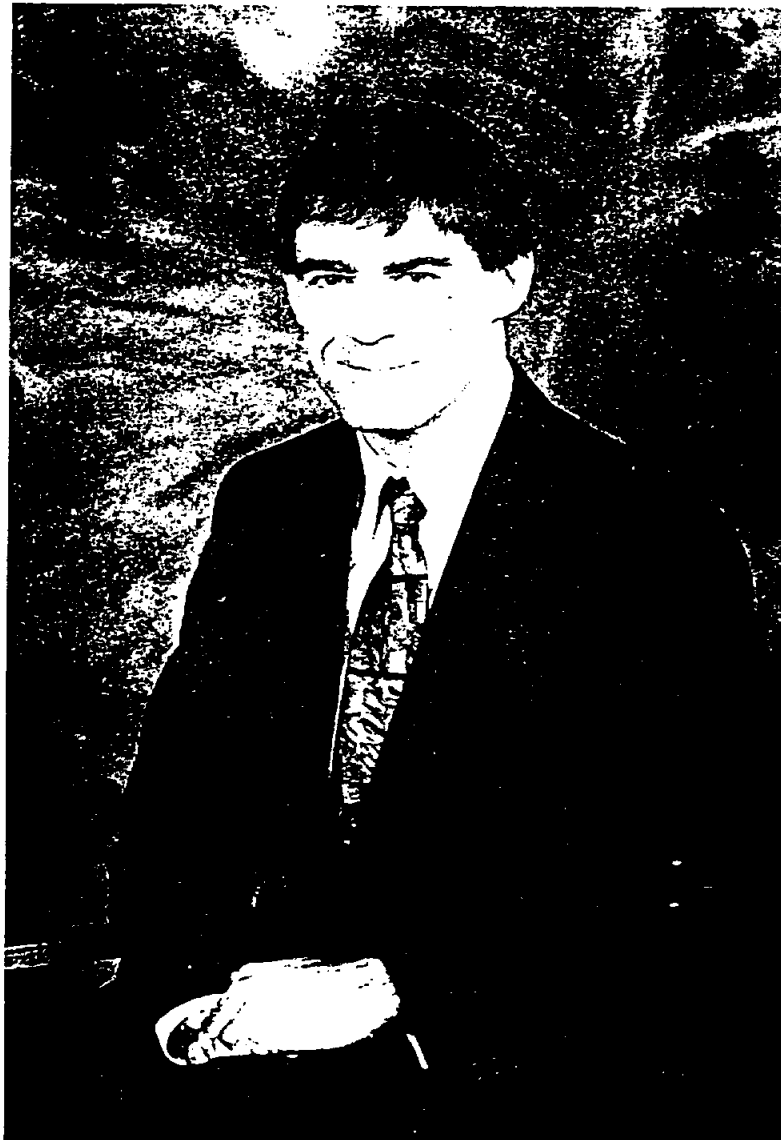
Offshore Engineering, An Introduction to, is a timely and most welcome addition to the library of the Offshore Industry. Whilst there are numerous highly specialised books available there are few, if any which deal with the Offshore Industry as a whole and here, in one volume is a comprehensive study of the subject which takes the reader from exploration, through construction and into production.

Offshore Engineering explains, superbly and lucidly, the key aspects of the various disciplines and places a wealth of essential information at the finger tips of the reader. The list of references which guide the reader to more specialised information is particularly valuable.

Today, the offshore engineer is required to carry out an enormous range of tasks and a full appreciation of the industry is an essential prerequisite to success. This book should be on the bookshelf, if not a permanent part of every engineers baggage. It will be as valuable to the new recruit to the industry as to the experienced engineer embarking upon a new field of work.

## THE AUTHOR

The author, Angus Mather, commenced his career as a mechanical technician apprentice with the Ministry of Defence at Her Majesty's Dockyard, Devonport. This was followed by 10 years service as an engineer officer in the British Merchant Navy before joining Lloyd's Register of Shipping. Employed as an engineer surveyor, Angus was primarily involved with oil and gas related projects, both on and offshore, in the UK and the Middle East. Today, Angus works for one of the largest engineering companies in the world.



## PREFACE

Offshore engineering encompasses a considerable number of very specialized and often completely unrelated disciplines. They may be categorised into three basic activities, namely Construction, Production and Reservoir Engineering and this book has been written, not as a definitive manual but as a general introduction to explain the essential features of these core activities.

It is hoped that the material contained within will provide the new recruit to the industry with a basic appreciation of what is a relatively complex subject, whilst at the same time providing the more experienced individuals with a broader perspective of activities outside of their own particular speciality. The decision as to what topics should be included and the depth to which they should be discussed are based largely on the authors personal experience of what information is required to create an overall picture of the offshore environment from, exploration to production.

Whilst frequent references are made to the oil and gas industries of the North Sea the bulk of the text is of a more general nature and thus applicable to offshore engineering on a global basis. Units of measurement are quoted in both imperial and metric with preference being given to the unit most frequently associated with a particular discipline.

Angus Mather  
Suffolk,  
January 1995

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Tony Wilks for the photographs of drill floor activities and the diving support vessels.

Alan O' Neill and Charles Hodge Photography, Lowestoft, for all other photographs, and the preparation of all photographic prints.

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## ABBREVIATIONS

ABS	American Bureau of Shipping
AC	Alternating current
ACoP	Approved code of practise
AISI	American Iron and Steel Institute
AIT	Auto ignition temperature
ALARP	As low as reasonably practicable
ANSI	American National Standards Institute
APAU	Accident Prevention Advisory Unit (of HSE)
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASNT	American Society for Non-Destructive Testing
ASTM	American Society for Testing and Materials
AWS	American Welding Society
BA	Breathing apparatus
BASEEFA	British Approval Service for Electrical Equipment in Flammable Atmospheres
BOP	Blowout preventer
BPD	Barrels per day
BS	British Standard
BV	Bureau Veritas
CA	Certifying Authority
CAA	Civil Aviation Authority
CALM	Catenary anchor leg mooring
CE	Carbon Equivalent
CIMAH	Control of Industrial Major Accident Hazards
CoF	Certificate of Fitness
COSHH	Control of Substances Hazardous to Health
CP	Cathodic protection
CRINE	Cost reduction in the new era
CSO	Continental Shelf Operations Notice
CSWIP	Certification scheme for weld inspection personnel
CTOD	Crack tip opening displacement
DC	Direct current
DDC	Deck decompression chamber
DEG	Duoethylene glycol
DEn	Department of Energy
DIN	Deutsches Institut für Normung
DNV	Det Norske Veritas
DoT	Department of Transport
DP	Design pressure
DP	Dynamic positioning
DSM	Diving safety memorandum
DSV	Diving support vessel
DT	Design temperature
DTI	Department of Trade and Industry

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EEMUA	Engineering Equipment Material Users Association
EERA	Evacuation, escape and rescue analysis
EOR	Enhanced oil recovery
EPC	Engineer, procure and construct
EPIC	Engineer, procure, install and construct
EPS	Emergency power supply
ESD	Emergency shutdown
ESDV	Emergency shutdown valve
FEA	Fire and explosion analysis
F&G	Fire and gas
FPS	Floating production system
FPSO	Floating, production, storage and offloading facility
FPV	Floating production vessel
FRAMS	Floating riser and mooring system
FRC	Fast rescue craft
FSA	Formal safety assessment
FSU	Floating storage unit
GA	General alarm
GBS	Gravity base structure
GL	Germanischer Lloyd
HAZ	Heat affected zone
HAZAN	Hazard analysis
HAZOP	Hazard and operability study
HF	High frequency
HGT	High pressure grease tube
HIPS	High integrity protection system
HLO	Helicopter landing officer
HMSO	Her Majesty's Stationary Office
HP	High pressure
HSC	Health and Safety Commission
HSE	Health and Safety Executive
HSWA	Health and Safety at Work
HVAC	Heating, ventilating and air conditioning
IMO	International Maritime Organisation
IP	Institute of Petroleum
ISO	International Standards Organization
JT	Joule Thompson
KO	Knock out
LCV	Level control valve
LEL	Lower explosive limit
LIC	Level indicator controller
LNG	Liquefied natural gas
LP	Low pressure

- Heat affected zone (HAZ)** - That portion of the base metal which has not been melted, but whose mechanical properties or microstructure have been affected by the heat generated during the welding process.
- Intrinsically safe** - Electrical equipment which is incapable of igniting a flammable gas mixture or combustible materials.
- Installation** - May be fixed or mobile and used directly or indirectly for the exploration or production of mineral resources.
- Installation, fixed** - A fixed offshore structure involved in the production of oil or gas which may be constructed of steel or concrete. Term used frequently in the UK to describe an offshore installation.
- Jacket** - Steel support framework used to support platform topsides.
- J-T valve** - Throttle valve used to reduce the pressure and temperature of a gas stream, associated with the NGL removal process.
- Knock out** - Removal of liquids from a gas stream within a pressure vessel.
- Lower explosive limit (LEL)** - The lowest concentration by volume of combustible gases in mixture with air that can be ignited at ambient temperature conditions.
- LNG** - Liquefied natural gas, gaseous at ambient temperatures and pressures but held in the liquid state by very low temperatures to facilitate storage and transportation in insulated vessels.
- LPG** - Liquefied petroleum gas, essentially propane and butane held in the liquid state under pressure to facilitate storage and transportation.
- Manifold** - An assembly of pipes, valves and fittings by which fluid from one or more sources is selectively directed to various process systems.
- Marine drilling riser** - Pipe extending from the blowout preventer on the seabed to the drilling rig on the surface, to permit the return of the drilling mud.
- Microwave** - High frequency multi channel radio communications system designed to carry information between two points linked by line of sight transmission.
- Mobile installation** - One which can be moved from place to place without major dismantling or modification.
- Module** - Self contained liftable package forming part of the topside facilities of an offshore installation. e.g. accommodation module, compressor module, drilling module etc..
- Multiphase** - Practice of flowing unstabilised well fluids (oil with high gas content) in a single pipeline by boosting the pressure to prevent vaporisation of the dissolved gasses.
- Natural gas** - Hydrocarbon gas occurring naturally from underground reservoirs both on and offshore.

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**NGL** - Natural gas liquids, a mixture of hydrocarbon liquids which include butane and ethane obtained from natural gas. May be produced from condensate reservoirs but more probably produced as a by product of oil production.

**Nipple** - A section of threaded or socket welded pipe used as an appurtenance that is less than 12 inches in length. Often used to describe any short length of open ended pipe.

**Nozzle** - Flanged inlet or outlet connection on a pressure vessel.

**Mudline** - Seabed.

**Packer** - Device for sealing one casing string from another, or from the production tubing.

**Pedestal** - Large diameter, vertical tube or tub onto which a crane is attached.

**Photogrammetric** - The use of still photography to capture dimensional information for transposing into drawings.

**Pig** - Spherical device inserted in to a gas subsea pipeline to sweep the line of deposits of rust, scale and condensed liquids. May also be used to clean oil pipelines of wax and may be "intelligent", that is containing measuring and inspection equipment.

**Pig trap** - A pressure chamber permitting the entry or removal of equipment into the subsea pipeline, normally pigs.

**Pipeline** - Piping used to convey fluids between platforms or between a platform and a shore facility.

**Pipe spool** - Single length of pipe with flanged ends.

**Platform, offshore** - A fixed offshore structure involved in the production of oil or gas which may be constructed of steel or concrete. Term used frequently by Americans to describe an offshore installation.

**Pressure vessel** - Container, normally cylindrical used to contain internal, or occasionally external pressure.

**Produced water** - Formation water removed from the oil and gas in the process pressure vessels.

**Production separator** - Main process vessel used primarily for the separation of gas, oil (and condensate) and water.

**Production tubing** - Pipe used in wells to conduct fluid from the producing formation into the Christmas tree. Unlike the casing the tubing is designed to be replaced during the life of the well, if required.

**Purge** - Maintain gas flow in an over rich, or lean concentration so as to avoid the build up of oxygen and an explosive mixture.

**Quality assurance** - A sequence of planned and systematic actions necessary to provide adequate confidence that a product or service will satisfy given requirements of quality.

**Quality control** - The operational techniques and activities that are used to ensure that a quality product or service will be produced.

**Rig** - A term normally associated with drilling equipment, that is to say a drilling rig. Also a slang term used extensively to describe any of the structures and vessels associated with oil and gas exploration and production.

**Riser** - The vertical portion of a subsea pipeline (including the bottom bend) arriving on or departing from a platform.

**Rock dumping** - Deposition of rocks onto subsea pipelines to provide protection against anchors and fisherman's nets when burying the pipe is impractical. Rocks and gravel may also be dumped around subsea wellheads and jacket legs to repair scour damage.

**Seismic survey** - The use of artificially generated sound waves to determine the type of rock formations below the ground or under the sea bed by monitoring the reflected sound wave signals.

**Scour** - Removal of the seabed in the vicinity of a jacket, subsea wellhead or pipeline by tidal action.

**Scrubber** - Pressure vessel containing equipment designed to remove or scrub liquids from a gas stream.

**Shuttle tanker** - Moderate sized oil tanker used to transport oil from larger vessels into port.

**Skid** - Steel framework used to contain equipment, may be transportable.

**Stress corrosion cracking** - The cracking which results from a combination of stress and corrosion.

**Slew ring bearing** - Large ball or roller bearing which connects crane to pedestal and permits rotation.

**Slug** - An accumulation of water (may also be sand or condensate) in a gas pipeline.

**Spudding** - A term used to describe the insertion of the conductor into the seabed when drilling a well. May also be used to describe the process of setting the legs of a jack-up into the seabed.

**Stinger** - Tubular steel support frame attached to the stern of a pipelay barge to control the bending of the pipe as it enters the water.

**Stripping** - The removal or replacement of drill pipe or tubing strings from a well under pressure using a stripping BOP.

**Stripping gas** - Gas, normally process gas used to assist in the purification of a liquid by reducing the partial pressure of gaseous contaminants to encourage vaporisation.

**Swabbing** - The lowering of the hydrostatic pressure in the hole due to the upward movement of the drill pipe and/or tools. Also the use of wireline equipment to clean a well by scooping out liquids.

**Sulphide stress cracking** - Cracking of metallic materials due to exposure to fluids containing hydrogen sulphide.

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**Telemetry** - System for the collection, collation and transmission of information to a remote source using radio, satellite, fibre optics or cable links. Also associated with the remote control of process equipment.

**Third party gas** - Term used to describe gas sold direct from oil company to parties other than British Gas, the previous monopoly holders in the UK.

**Throttle** - Regulation of fluid flow by a throttling valve or fixed orifice.

**Topsides** - Upper part of a fixed installation which sits on top of the jacket and consists of the decks, accommodation and process equipment.

**Vam** - Trade name for casing thread produced by the Vallourec company of France.

**Vent** - A pipe or fitting on a vessel that can be opened to the atmosphere.

**Vent stack** - Open ended pipe and support framework used to discharge vapours into the atmosphere at a safe location above the installation without combustion.

**Wellhead** - Permanent equipment used to secure and seal the casings and production tubing and to provide a mounting place for the Christmas trees.

**Wireline** - Equipment used to introduce tools into the well bore under pressure.

**Workover** - Re-entry into a completed well for modification or repair work.

**Workover rig** - Normally a smaller, portable version of the main drilling derrick which can be used to carry out work over operations on installations which do not have a permanent derrick.

# STANDARDS, GUIDANCE NOTES AND CODES OF PRACTICE

Listed below are standards and specifications referenced in this book. The list is not exhaustive but contains standards and guidance notes which are in frequent use and are a valuable source of reference.

## BRITISH STANDARDS

BS 2600	Radiographic examination of fusion welded butt joints in steel.
BS 2910	Radiographic examination of fusion welded circumferential butt joints in steel pipes.
BS 3351	(withdrawn). Specification for piping systems for petroleum refineries and petrochemical plants.
BS 3923	Ultrasonic examination of welds.
BS 4137	Guide to Selection of Equipment for use in Division 2 Areas.
BS 4360	Weldable Structural Steels.
BS 4416	Penetrant testing of welded or brazed joints in metals.
BS 4515	Welding of steel pipelines on land and offshore.
BS 4683	Electrical Apparatus for Explosive Atmospheres.
BS 4870	Specification for approval testing of welding procedures.
BS 4871	Specification for approval testing of welders working to approved welding procedures.
BS 5135	Metal arc welding of carbon and manganese steels.
BS 5169	Specification for fusion welded air receivers.
BS 5289	Code of practise. Visual inspection of fusion welded joints.
BS 5345	Classification of Hazardous Areas and selection of Equipment for use in Hazardous Areas.
BS 5490	Specification for Degrees of Protection provided by Enclosures.
BS 5500	Unfired Fusion Welded Pressure Vessels.
BS 5501	Electrical Apparatus for Potentially Explosive Atmospheres.
BS 5750	Quality systems.

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- BS 6072            Methods for magnetic particle flaw detection.
- BS 6443            Penetrant flaw detection.
- BS 6755            Part 2. Specification for fire type testing requirements (valves).
- BS 8010.            Code of Practice for Pipelines.
- B.S. EN 287        Approval testing of welders for fusion welding (formerly BS 4871).
- B.S. EN 288        Specification and approval of welding procedures for metallic materials (formerly BS 4870).
- EEMUA No. 150    Steel Specification for Offshore Structures
- EEMUA No. 158    Construction specification for fixed offshore structures in the North Sea.

## **GUIDANCE NOTES**

Department of Energy Offshore Installations: Guidance on Design Construction and Certification.

Department of Energy Offshore Installations: Guidance on Fire Fighting Equipment.

Department of Energy Offshore Installations: Guidance on Life Saving Appliances.

Department of Energy Offshore Installations: Guidance on Emergency Pipe-Line Valve.

Institute of Petroleum Code of Safe Practice Part 1, 1965.

Guidance on Permit to Work Systems in the Petroleum Industry (Health and Safety Commission/Oil Industry Advisory Committee, 1991).

Approved Code of Practice (ACoP) on the prevention of fire and explosion, and emergency response on offshore installations (Health and Safety Executive).

## **AMERICAN STANDARDS**

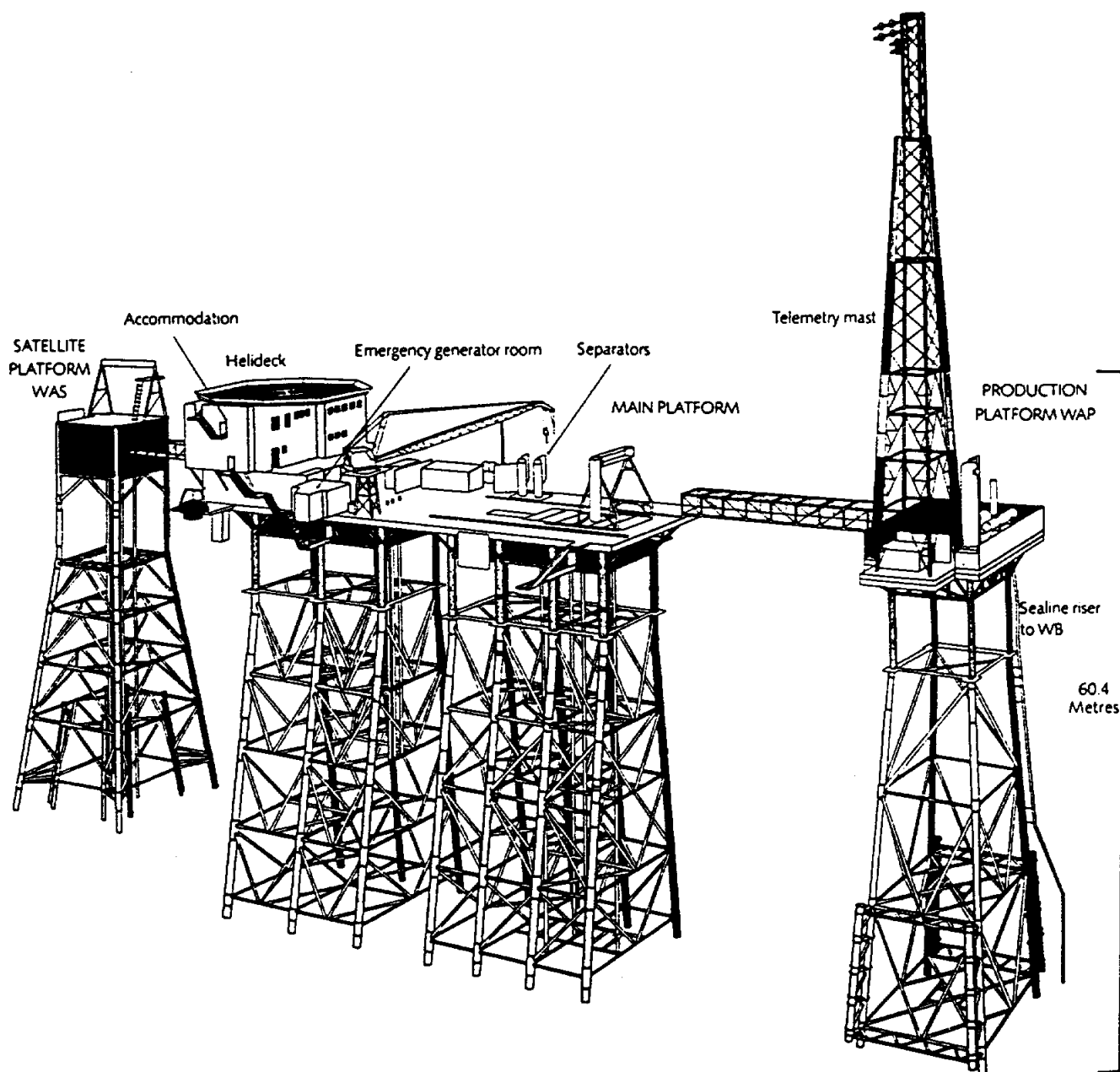
- ASME IX -        Boiler and pressure vessel code.
- AWS D1.1 -       Structural Welding Code.
- ANSI/ASME B31.3 - Chemical plant and petroleum refinery piping.
- ANSI B16.5 -     Steel pipe flanges and flanged fittings.
- ANSI B16.9 -     Wrought steel butt welded fittings.
- ANSI B16.11 -    Forged steel fittings, socket welded and threaded.



- API Spec 5L - Specification for line pipe.
- API Spec 6A - Specification for Wellhead and Christmas Tree Equipment.
- API Spec 6AF - Specification for Fire Test for Valves.
- API Spec 14D - Specification for Surface Safety Valves and Underwater Safety Valves for Offshore Service.
- API Std 1104, - Standard for Welding Pipelines and Related Facilities.
- API RP 2A, Recommended Practice for Planning, Design and Construction of Fixed Offshore Platforms.
- API RP 2G, Recommended Practice for Production Facilities on Offshore Structures.  
(now discontinued)
- API RP 14C, Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms.
- API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems.
- API RP 16E, Recommended Practice for Design of Control Systems for Drilling Well Control Equipment.
- API RP 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells (now discontinued).
- API RP 64, Recommended Practice for Diverter Systems, Equipment and Operation.
- API RP 500, Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs on Land and on Marine Fixed and Mobile platforms.
- API RP 520, Recommended Practice for the Design and Installation of Pressure Relieving Systems in Refineries - Parts I and II.
- API RP 521, Guide for Pressure and Depressuring Systems.
- API RP 1111, Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines.
- ASTM A105 - Specification for Forgings, Carbon Steel, for Piping Components
- ASTM A106 - Specification for seamless carbon steel pipe
- ASTM A193 - Specification for Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature service.

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- ASTM A194 - Specification for Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service.
- ASTM A234 - Specification for Piping Fittings of wrought Carbon Steel and Alloy Steel for Moderate and Elevated Temperatures.
- ASTM A312 - Specification for seamless and welded austenitic stainless steel pipe.
- ASTM A320 - Specification for Alloy Steel Bolting Materials for Low-Temperature Service.
- ASTM A333 - Specification for seamless and welded steel pipe for low temperature service.
- ASTM A790 - Specification for seamless and welded ferritic/austenitic stainless steel tube for general service.
- ASTM A860 - Specification for high-strength butt-welding fittings of wrought high-strength low-alloy steel.
- MSS SP-44. Steel Pipe Line Flanges.
- MSS SP-75. Specification for high test wrought butt welding fittings.
- NACE MR-01-75. Sulphide Stress Cracking Resistant Material for Oilfield Equipment.
- NACE RP-01-76. Corrosion Control on Steel, Fixed Offshore Platforms Associated with Petroleum Production.



## GAS INSTALLATION

# **Chapter One**

## **OFFSHORE STRUCTURES AND SUPPORT VESSELS**

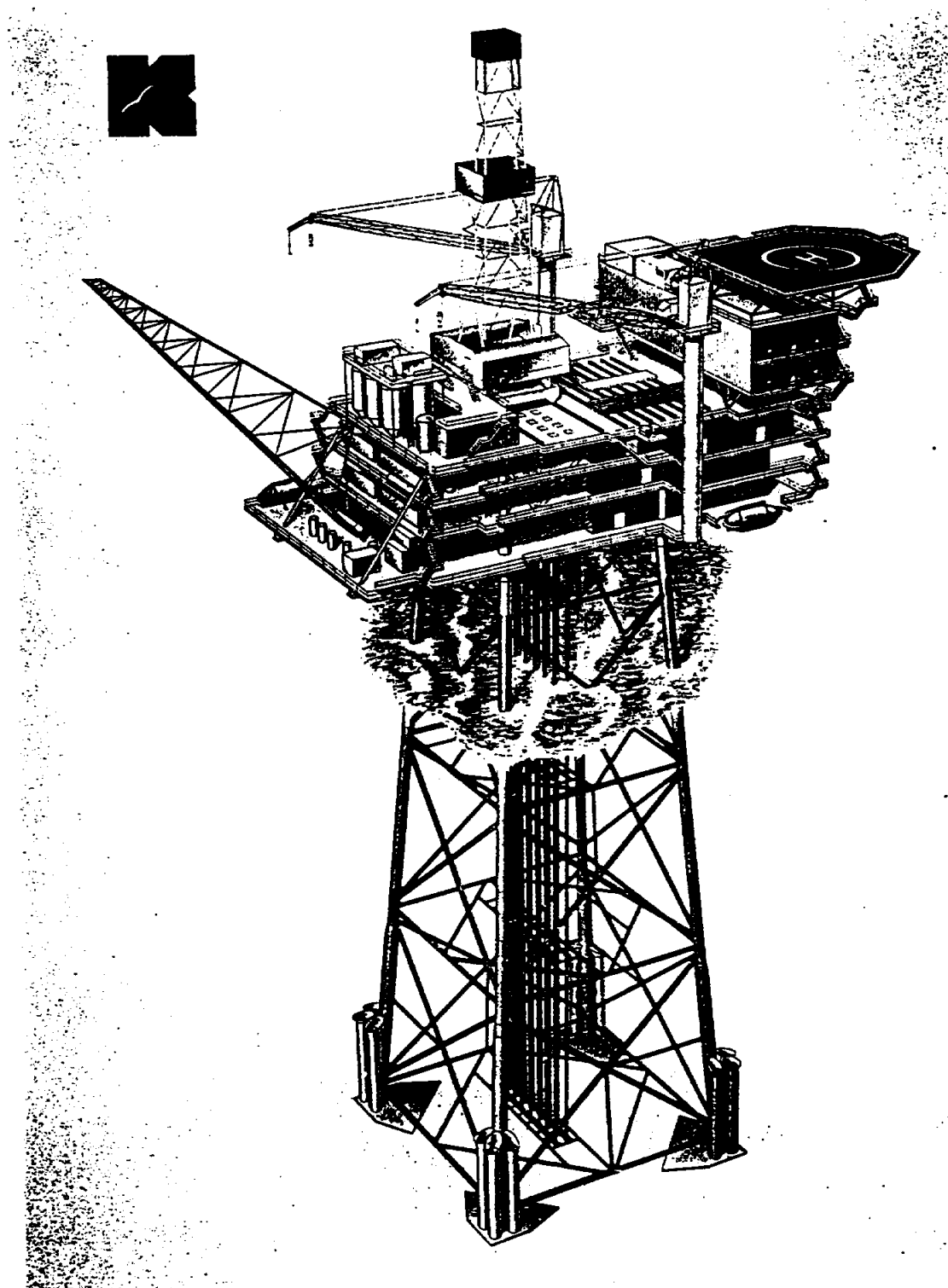
PART 1. OFFSHORE STRUCTURES.

PART 2. SUPPORT VESSELS.

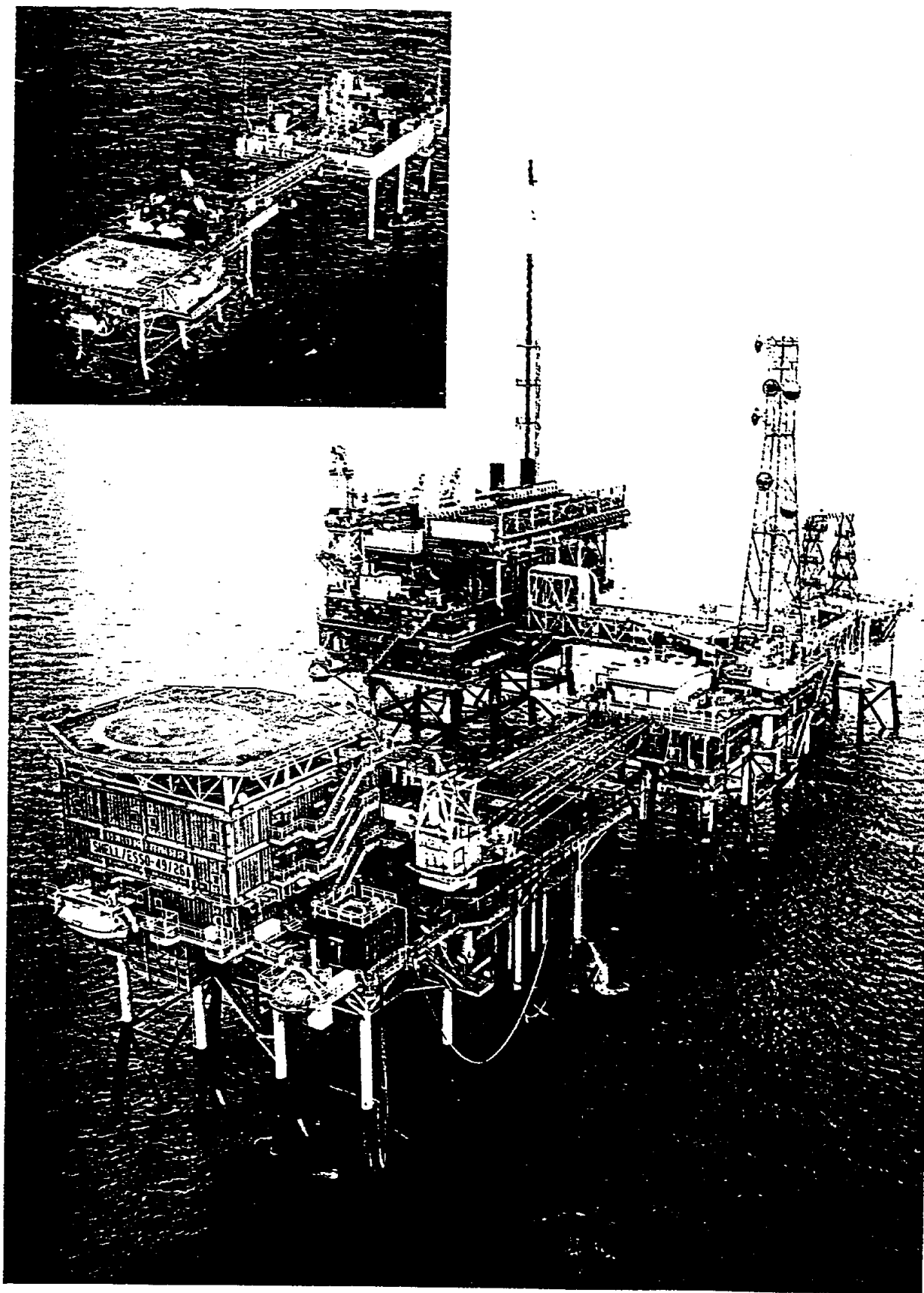
PART 3. OFFSHORE INSTALLATIONS - DESCRIPTION.

PART 4. FIXED STEEL STRUCTURES - INSTALLATION.

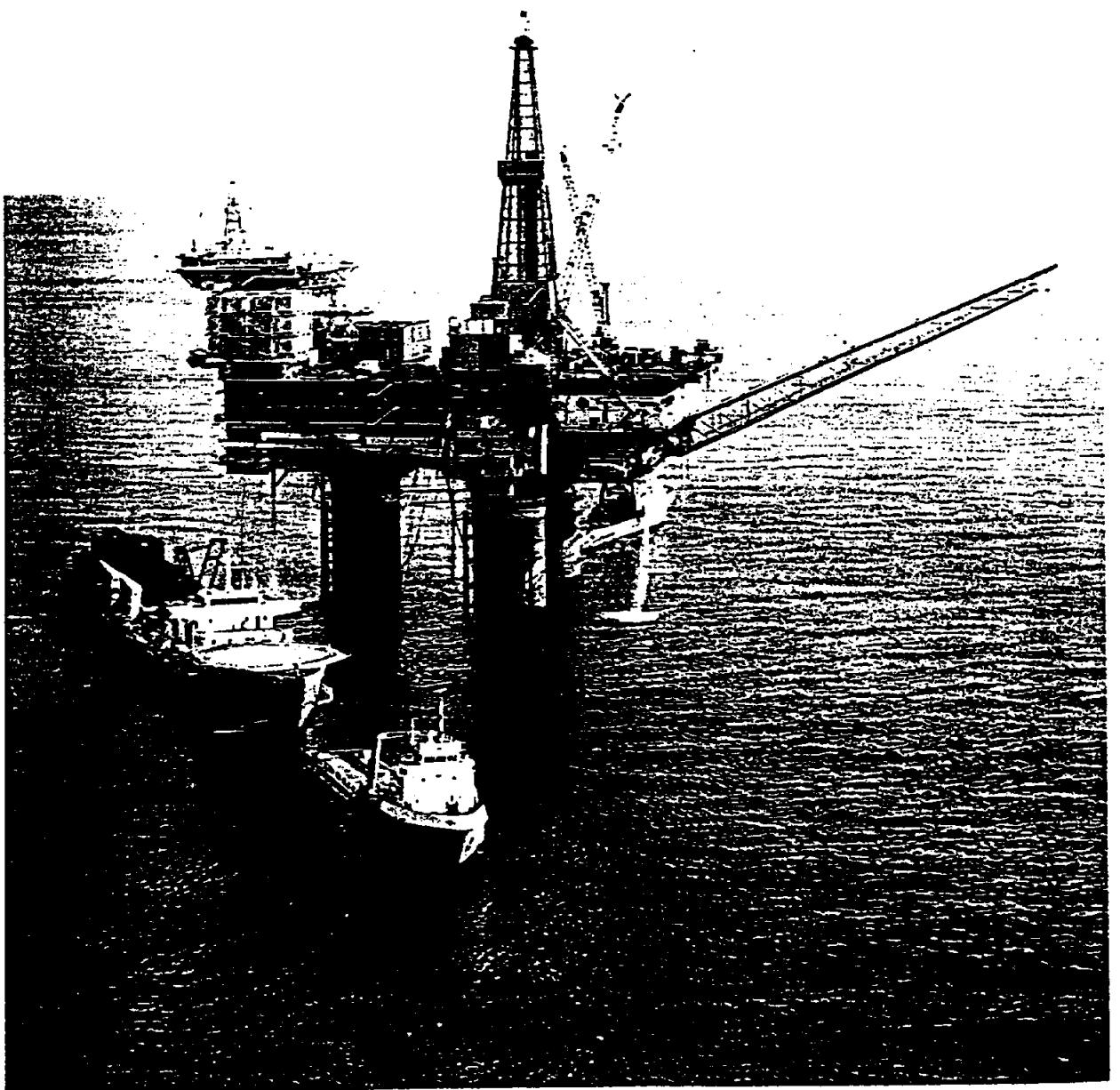




**FIXED STEEL INSTALLATION**

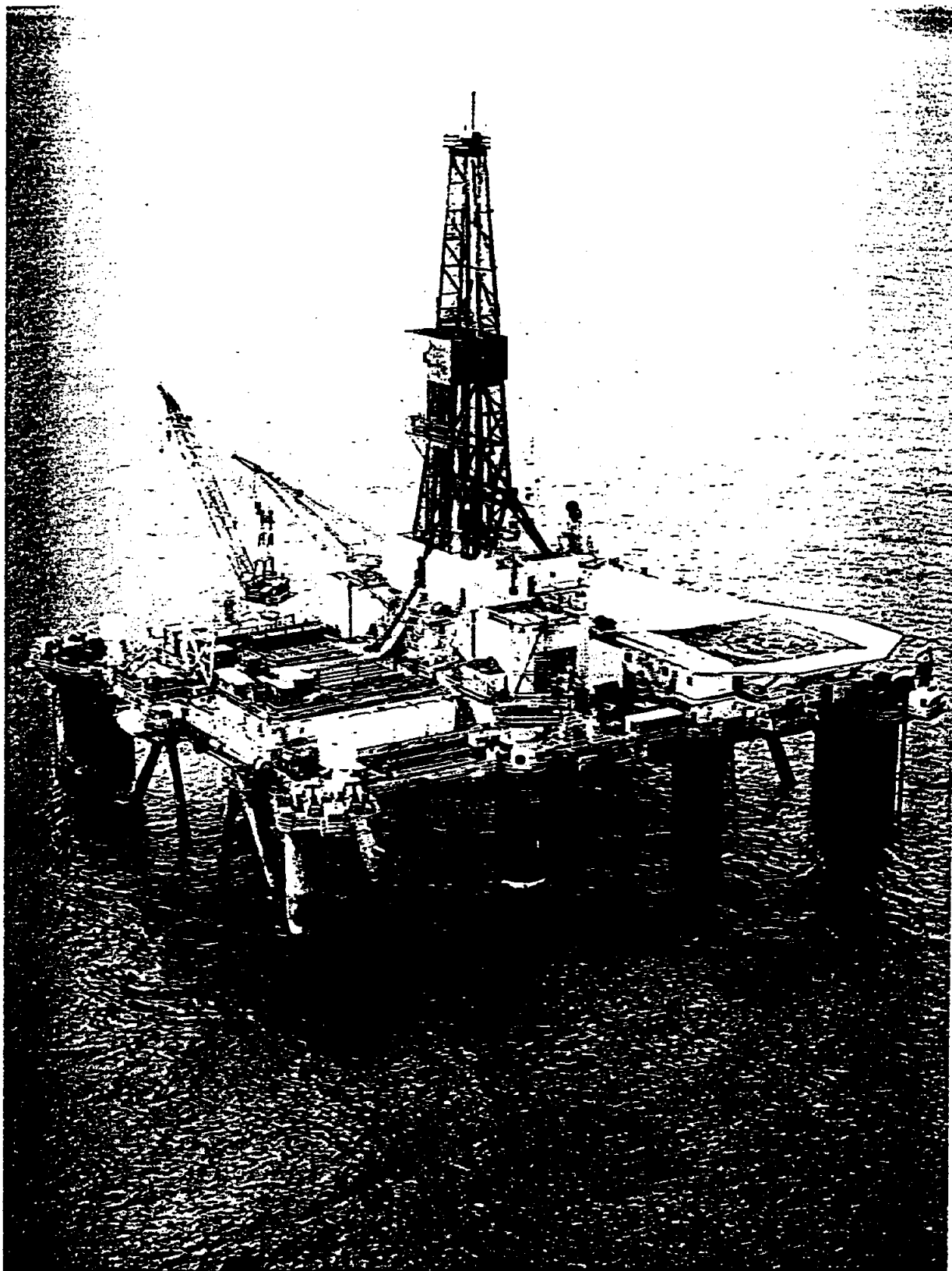


1 - Gas platforms. Shell/Esso Leman 49/26 Alpha multi jacket installation typical of the gas gathering and compression facilities found in the Southern North Sea.  
 Inset - Amoco Leman 49/27 Delta. Note the "piled barge" production platform.

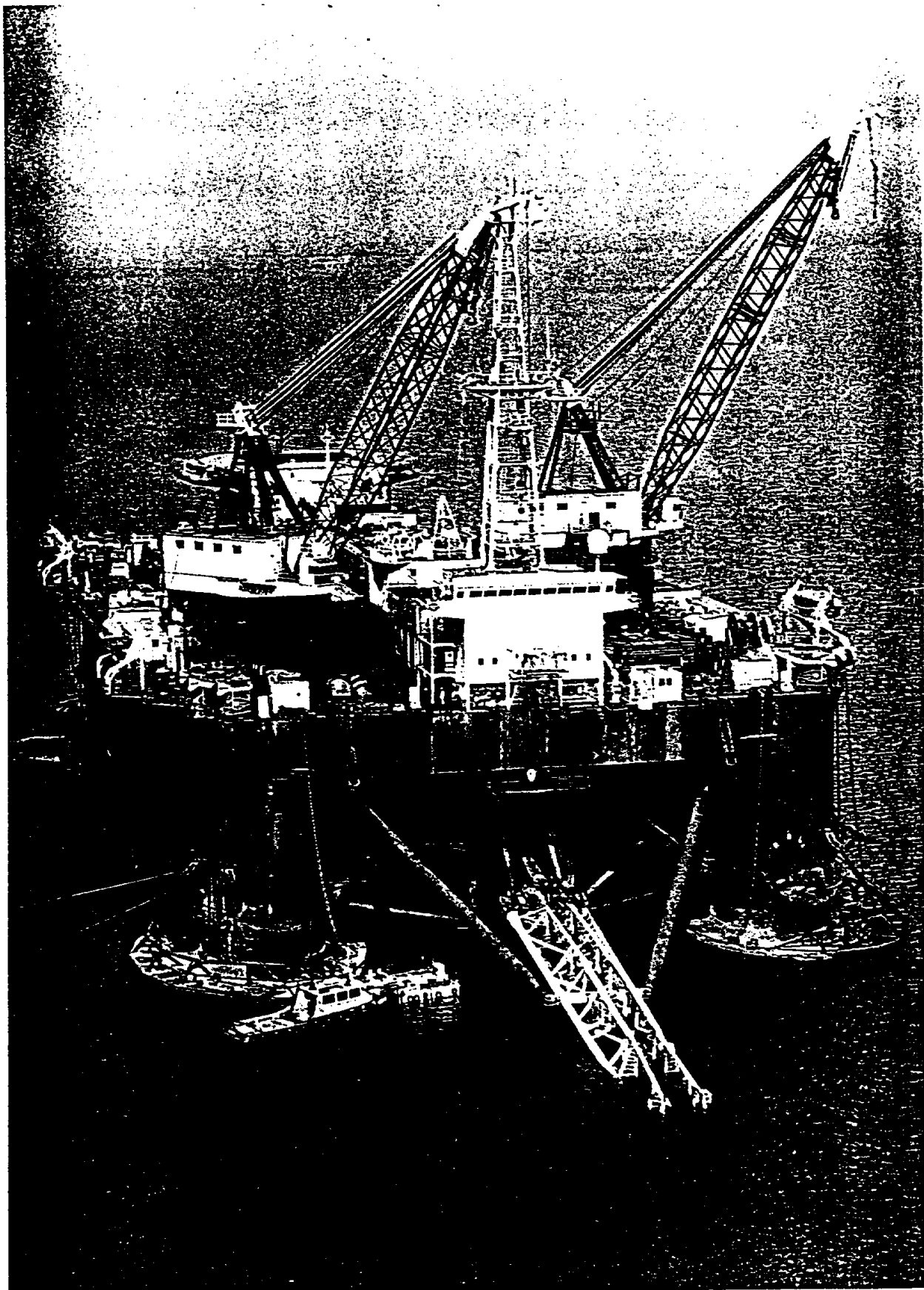


2 - The Shell/Esso Brent Delta concrete gravity base structure (GBS).

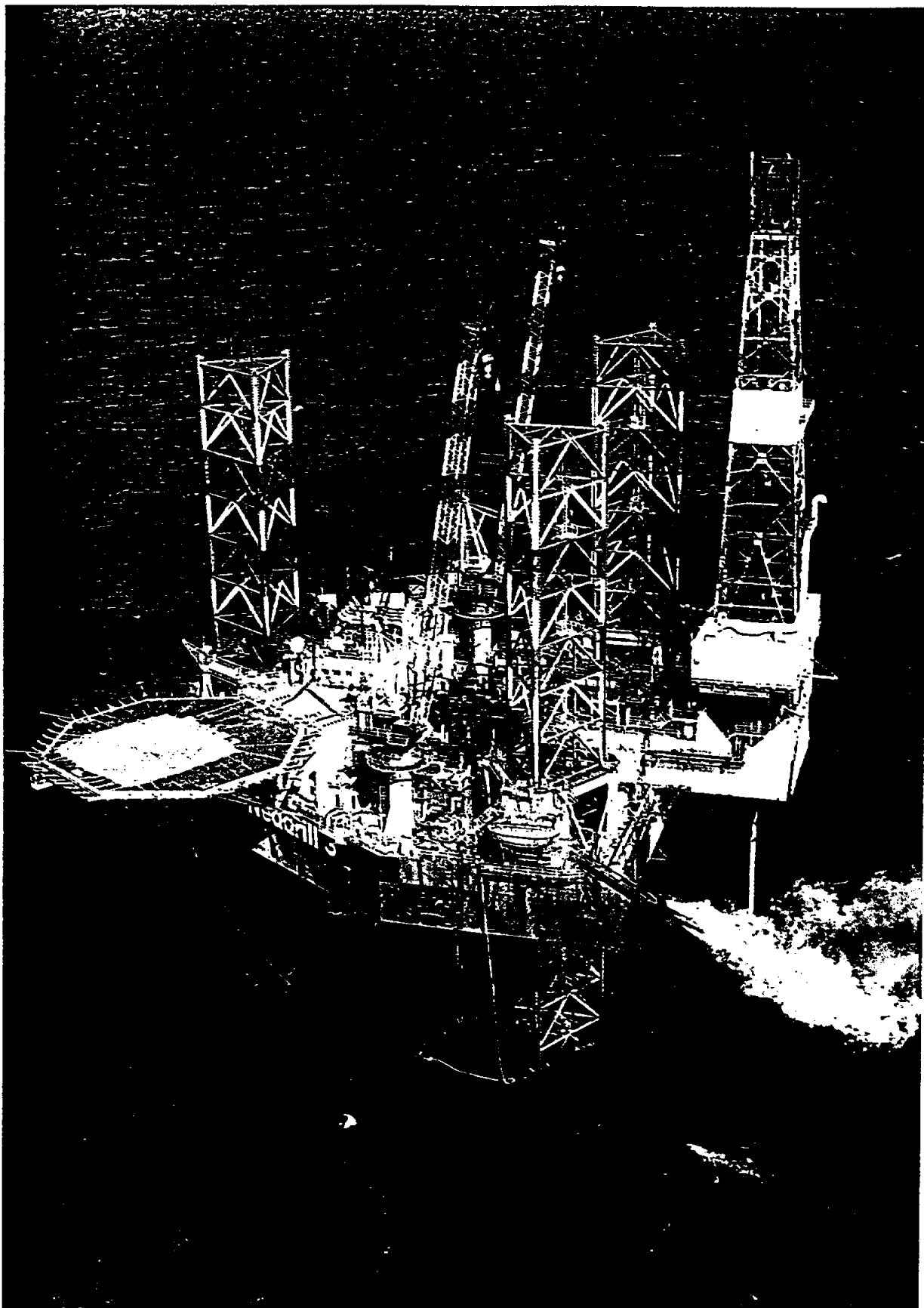




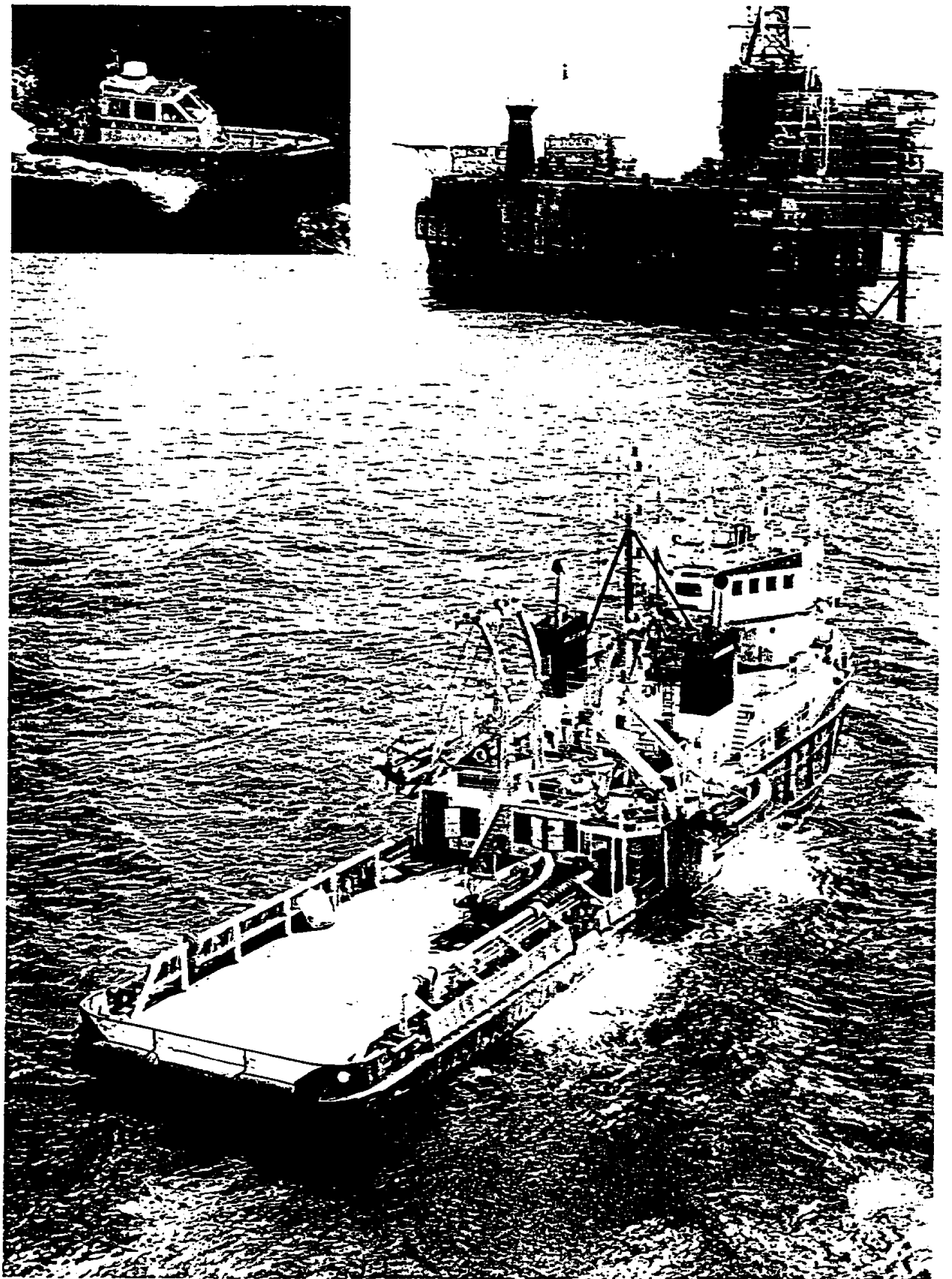
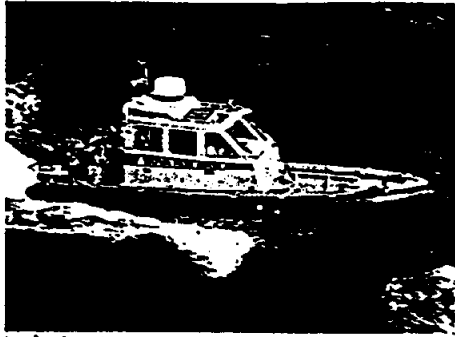
3 - The Shell Stadrigg semi-submersible drilling vessel involved in wildcat drilling operations.



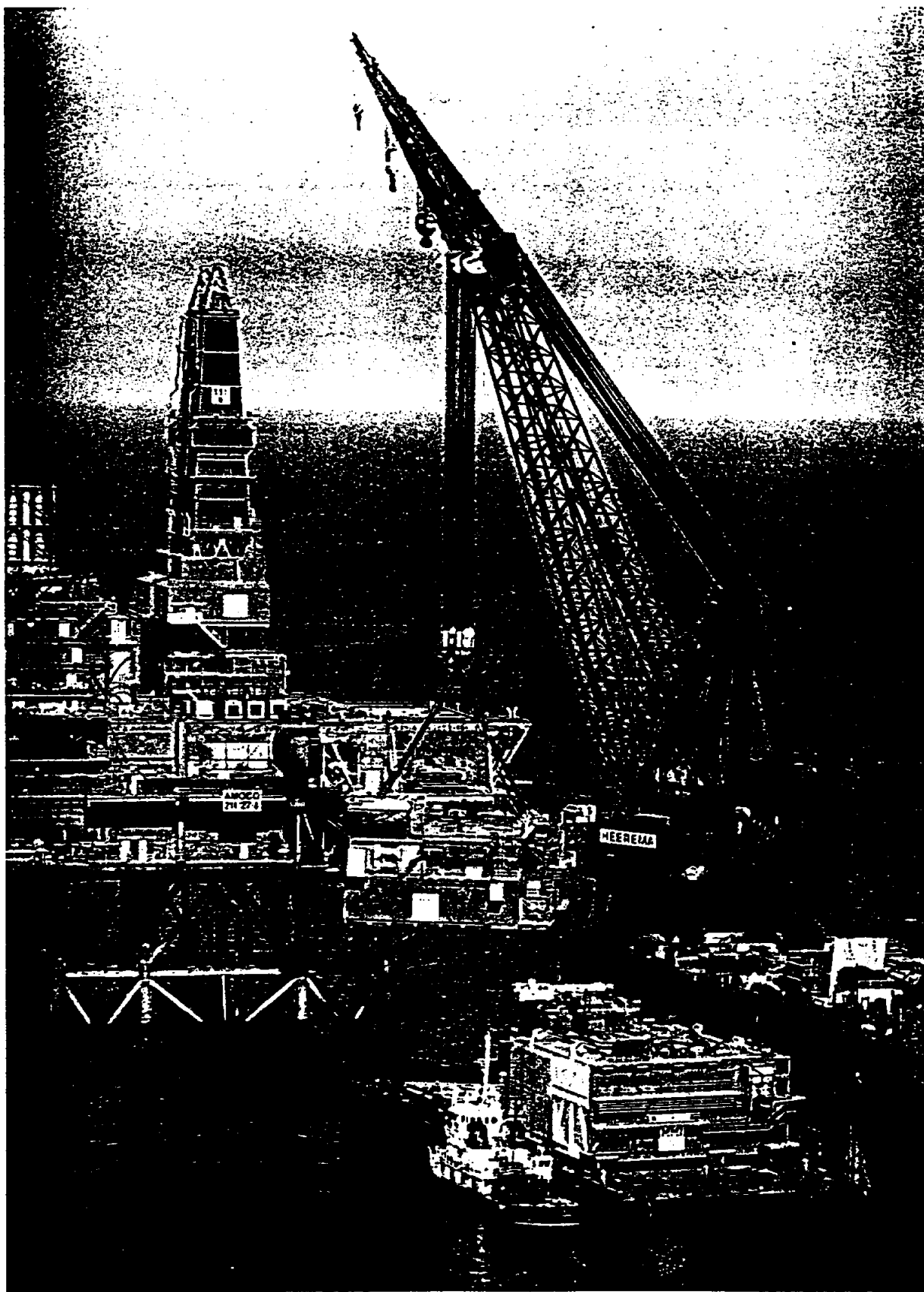
4 - The Castoro Sei semi-submersible pipelay vessel.  
The pipeline is guided into the sea from the "stinger" framework attached to the vessel's stern.



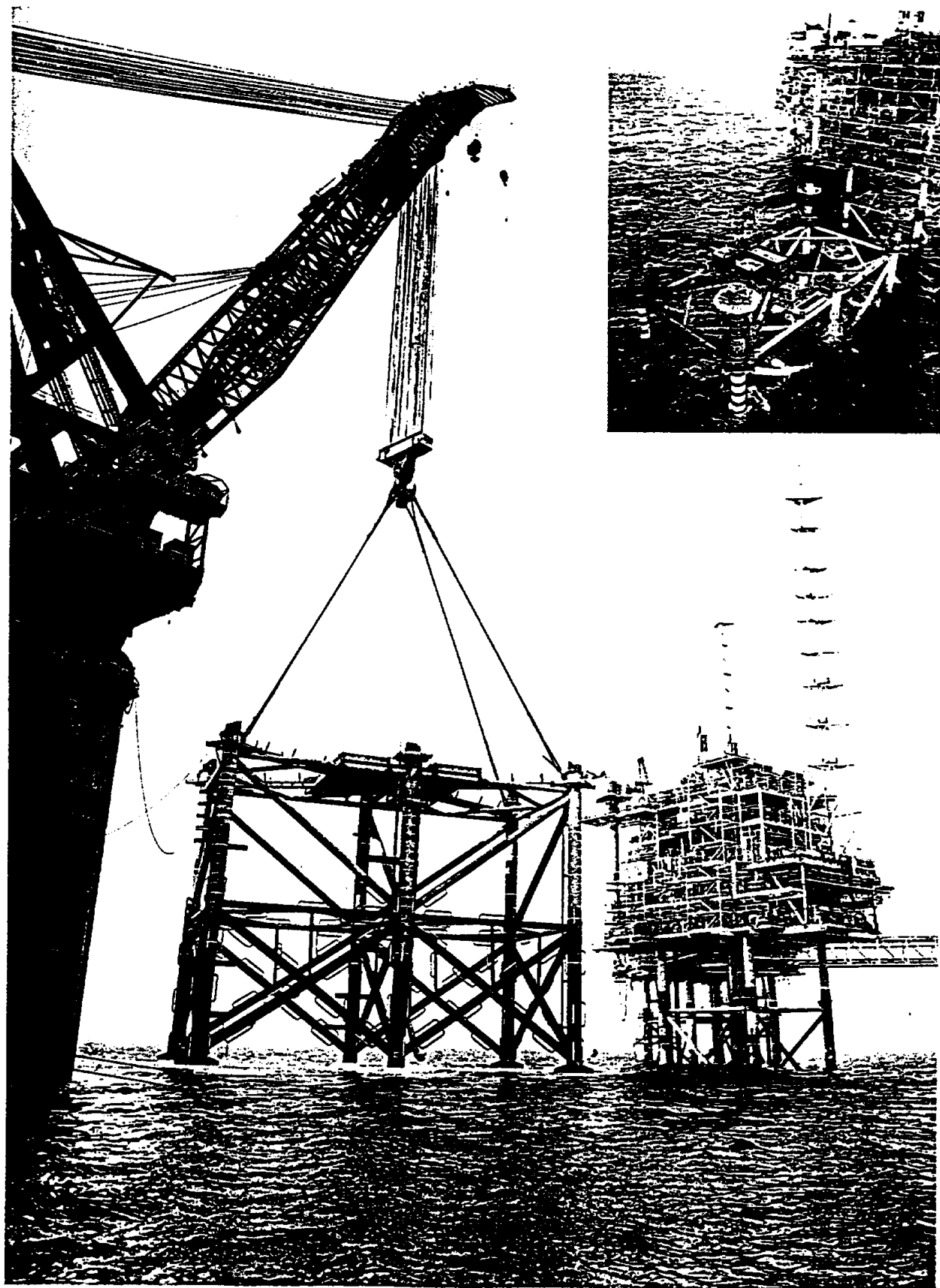
5 - The jack-up Neddrill 3 testing an exploration well. The gas is being flared from a temporary overboard vent boom.



6 - The Putford Artemis standby boat and the DB101 semi-submersible crane vessel (SSCV)  
at work installing a topside module.  
Inset - a fast rescue craft.



7 - Absolutely ideal conditions to lift 3,000 tonnes and demonstrate the capabilities of a semi-submersible heavy lift crane vessel (SSCV). The platform is the Amoco North West Hutton, physically one of the largest oil installations in the North Sea and the crane vessel is the Heerema Balder.



8 - The lowering of one of the Shell/Esso 48/19a Clipper jackets  
into the shallow waters of the southern North Sea by the heavy lift crane vessel the Hecremac DB102.  
Inset - installation of the jacket complete. Piles driven, welded, cut, dressed and awaiting the topside structure

## **Part 1. OFFSHORE STRUCTURES**

### **INTRODUCTION**

The structure shown opposite is instantly recognisable as an offshore rig. This type of structure, more correctly described as a fixed steel offshore installation, or platform forms the backbone of the offshore industry and there are in excess of 7,000 such structures dotted about the oceans of the world.

Not so familiar are the structures and vessels shown elsewhere in this chapter which provide assistance to, or are in competition with the fixed steel structure. They could all be loosely described as oil rigs (or gas rigs) which gives an indication as to the ambiguity of the expression and hints at the complexity of the offshore industry.

**The various rig/vessel types are:-**

1. Fixed steel structure.
2. Concrete gravity base structure.
3. Tension leg platform.
4. Semi-submersible vessel.
5. Floating production systems.
6. Self elevating jack-up.
7. Single point mooring.

The following is a brief description of each installation and its position within the offshore jig-saw puzzle.

### **1. FIXED STEEL STRUCTURES**

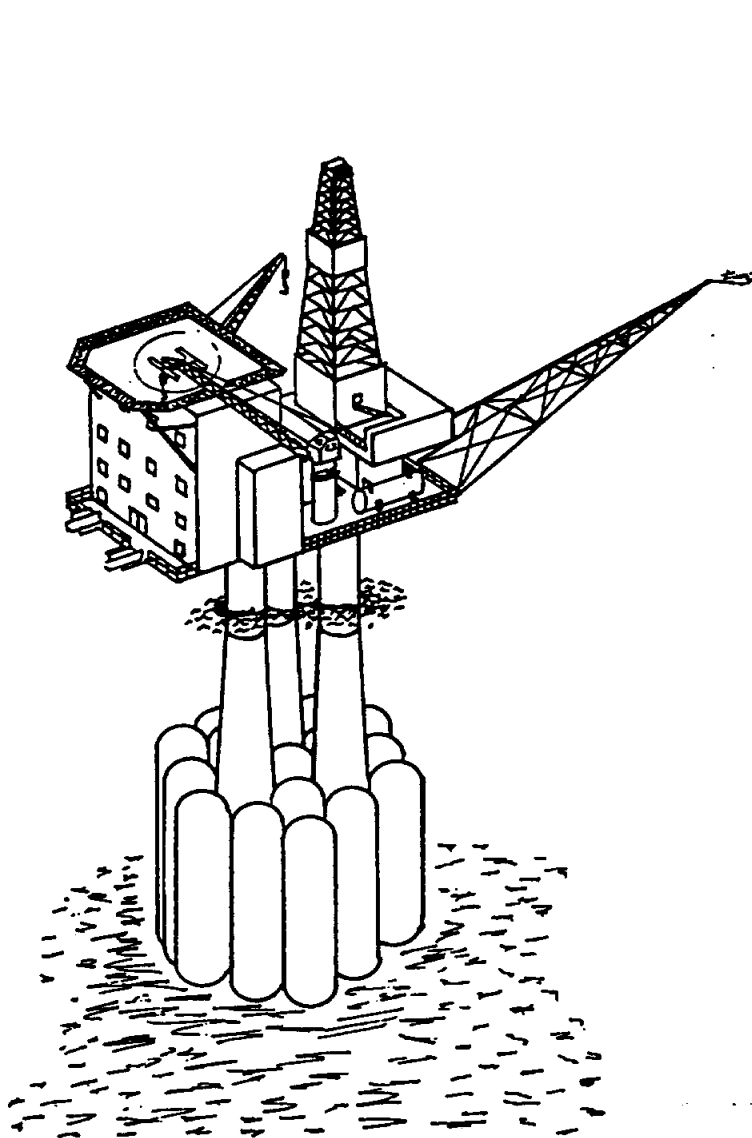
The traditional offshore installation shown utilises a welded steel, tubular framework or jacket to support the topside facilities and this arrangement is referred to as a fixed steel structure. The topside facilities will vary slightly depending on whether it is oil or gas that is being produced but they will include hydrocarbon process equipment, power generation, a helideck, and accommodation and hotel services designed to cater to the needs of personnel employed in the operation and maintenance of the installation.

The single jacket installation is typical of the rigs found in deep water environments such as the northern sector of the North Sea. It should be noted that the accommodation/helideck facilities are situated as far from the potentially dangerous hydrocarbon process area as is physically possible.

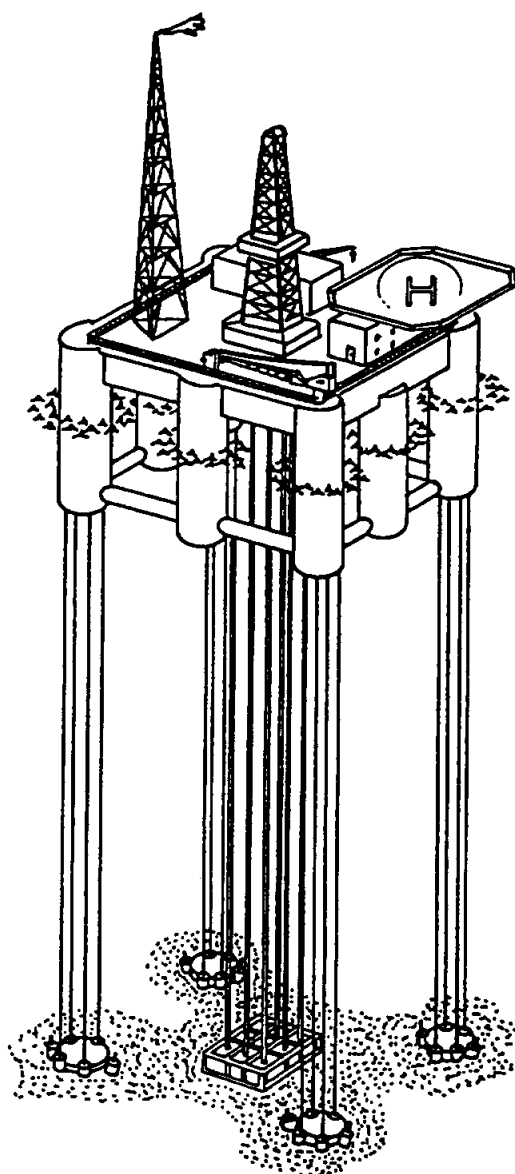
An installation may consist of any number of bridge linked jackets with modern designs tending to favour a separate jacket to house the accommodation and helideck. These multi-jacket installations tend to be restricted to shallow water developments where the construction costs are considerably less than their deep water counterparts.

Whilst the fixed steel structure is likely to remain as the industry's first choice of installation design based on operational requirements, its future use may well be restricted to the development of large fields located in intermediate water depths where a substantial return on the capital sums invested can be guaranteed. The ever changing demands of the offshore industry has spawned a number of competitors more ideally suited to specific applications.

The concrete structure has emerged as a viable alternative to the steel jacket but they both tend to suffer from the same inherent disadvantages when used to develop deep water reserves. The scantling requirements of structures that are capable of withstanding the extremes of weather conditions associated with the North Sea are considerable and this is reflected in the construction costs. Generally speaking the tension leg platform (TLP) or the floating production system (FPS) will be preferred for the development of deep water reserves. The FPS used in conjunction with sub-sea wells also represents the most cost effective solution for the exploitation of the smaller, marginal fields.



CONCRETE GRAVITY BASE



TENSION LEG PLATFORM (TLP)



## OFFSHORE STRUCTURES AND SUPPORT VESSELS

The design of a semi-sub does not permit the installation of an effective main propulsion plant. It is thus heavily dependant on the assistance of support ships for towage to its destination and for the deployment of anchors (typically eight). However, some vessels are fitted with computer controlled azimuthing thruster units which provide an accurate manoeuvring capability, particularly when operated through a satellite navigation system. This facility enables the semi-sub to hold station in water depths in excess of 650 metres (2,200 feet) where the laying of anchors may prove impractical.

The semi-sub represents the ideal choice of vessel for performing operations where accurate station keeping and exceptional stability are prerequisite to success. Depending on the equipment fitted to the main deck the vessel may perform any one of five roles.

### i) **HEAVY LIFT**

The semi-sub will most frequently be encountered in its role as a heavy lift crane barge used for the installation of offshore platforms. Over the years the lifting capacity of the cranes has steadily increased from 2,000 tonnes to 7,000 tonnes and the more modern vessels are fitted with tandem cranes which are capable of lifts of up to 14,000 tonnes.

### ii) **ACCOMMODATION**

Some of the older, smaller heavy lift semi-sub's are now used for modification or repair projects where the facility to provide extra accommodation and storage space take precedence over the lifting capacity of the crane. They have been joined by purpose built accommodation vessels or flotels with up to 800 beds which can remain in close attendance to fixed structures for months at a time. Transfer of personnel may be by bridge or by helicopter and again the inherent stability of the semi-sub ensures that the workforce sleep soundly, even during a winter in the North Sea.

### iii) **DRILLING EXPLORATION VESSEL**

Depending on water depth, the drilling of exploration wells will be carried out by either a self-elevating jack-up, a semi-submersible vessel or a drill ship. The jack-up is limited to operations in water depths of approximately 120 metres (400 feet) but no such restrictions apply to the semi-sub. The current world water depth drilling record stands at a formidable 2,250 metres (7,520 feet) at a field in the Gulf of Mexico.

The combination of satellite positioning, stability and an abundance of deck space for the storage of drill pipe and well test equipment make the semi-sub the first choice of vessel for deep water exploration projects.

### iv) **PIPELAY BARGE**

The sketch opposite shows a typical pipelay barge of the type which has installed nearly 10,000 kilometres of subsea pipeline in the North Sea during the past 25 years.

Once started, the laying of a subsea pipeline becomes a non-stop operation as the lay barge slowly winches its way forward on its anchors. A modern vessel can lay between 2 and 4 kilometres of pipeline a day, azimuthing thruster units often replacing the anchor spread.

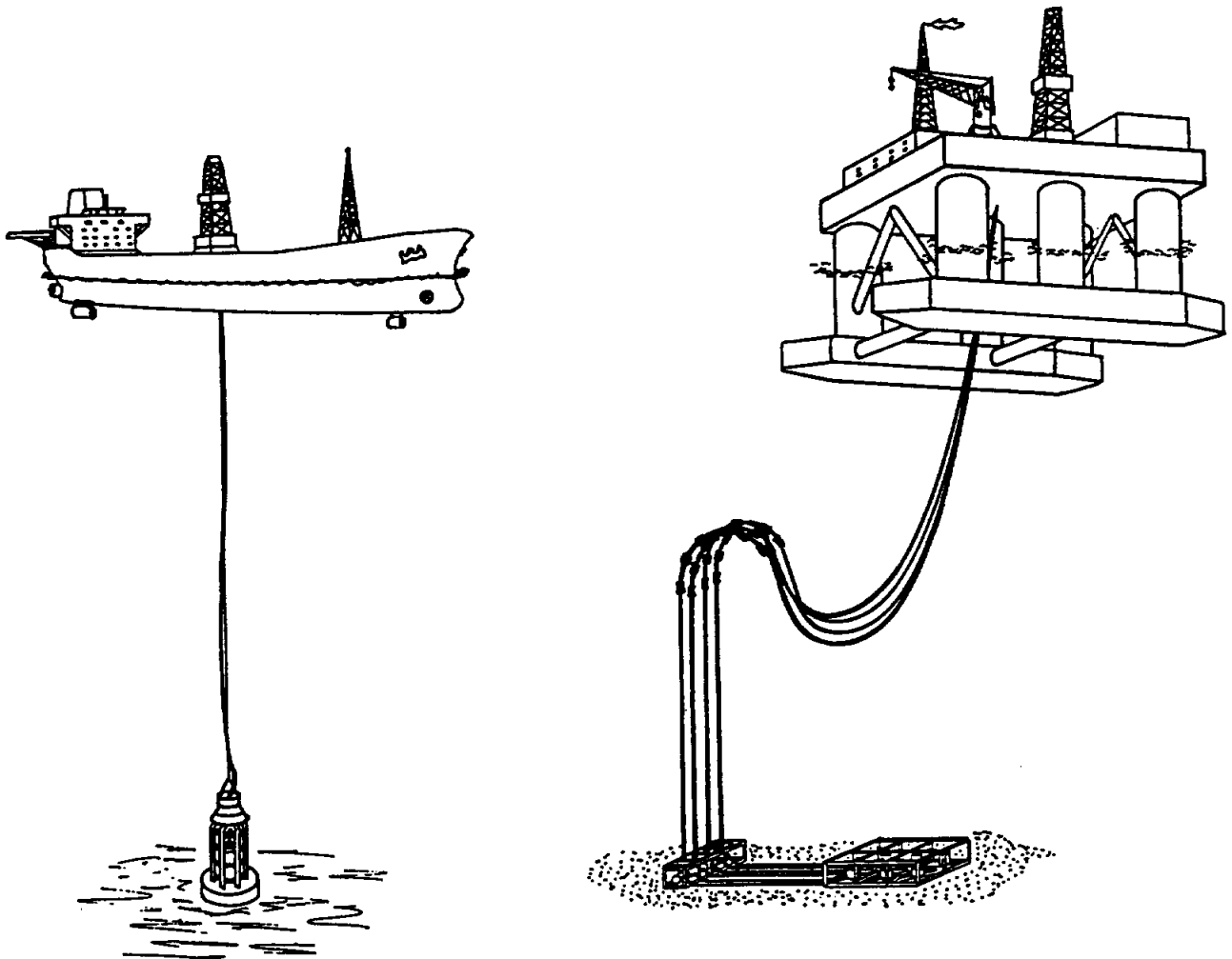
Subsea pipelines vary in diameter from 3" to 42" with 30" and 36" lines being favoured for the main transmission routes. The pipe is supplied to the barge in 12 metre lengths which are coated in concrete to provide corrosion protection and the negative buoyancy required to keep it on the sea bed.

On the barge the exposed ends of the pipes are welded together using a part manual, part automatic welding process. The welds are then X-rayed and if free from defects are given a protective coating of bitumen before being launched into the sea from the stinger framework situated on the stern of the vessel. The stinger prevents buckling of the pipe as it enters the water.

The completed pipeline will be subjected to a hydrostatic pressure test to prove its structural integrity before being trenched or covered in rocks to protect it from hazards such as fishermen's nets and ships anchors.

## 5. FLOATING PRODUCTION SYSTEMS (FPS)

A floating production system is in effect a floating oil rig. It contains all the equipment associated with a fixed installation and is used in conjunction with subsea wellheads to exploit moderate to deep water oil fields. The FPS is particularly suitable for the development of oil reserves where the installation of a fixed structure would be either impractical or prohibitively expensive.

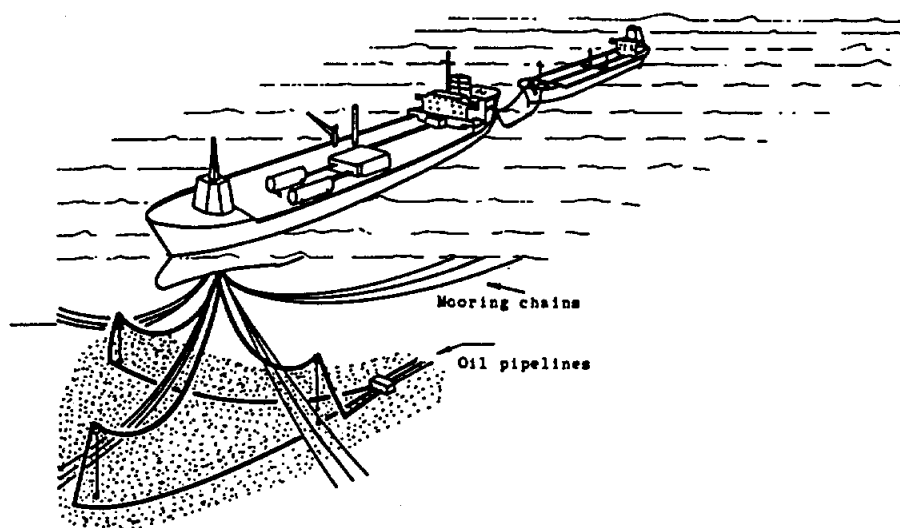


FLOATING PRODUCTION SYSTEMS (FPS)

## OFFSHORE STRUCTURES AND SUPPORT VESSELS

The majority of FPS's employ a semi-submersible barge to accommodate the process plant, although more recently there has been a significant increase in the number of companies opting for monohull designs, normally employing converted oil tankers. A spread of 8 to 12 anchors ensures that they remain on location whilst producing oil, the oil being extracted from the subsea wells through flexible flowlines designed to absorb any wave induced motion which might affect the position of the vessels.

The increase in the popularity of monohull floating production systems is largely due to the fact that processed oil can be stored on board the vessel prior to export, making them in effect Floating, Production, Storage and Offloading (FPSO) facilities. The oil is eventually discharged into shuttle tankers for transportation to a refinery. The processed oil from semi-submersible floating production systems may be discharged into a subsea pipeline, or transferred to a shuttle tanker via a single buoy mooring (SBM) for onward transportation.



### FLOATING PRODUCTION STORAGE AND OFFLOADING SYSTEM

The beauty of the floating production system lies in the fact that it can simply lift anchors and depart to pastures new when the oil reserves reach a commercially unprofitable level. This attractive feature has led to the evolution of a monohull FPS which can be used to develop marginal reserves located in more moderate water depths. Pioneered by British Petroleum (BP), these designs are often referred to as PSV's (Production Storage Vessel) and a dynamic positioning capability enables them to remain on station over the wells without the need to deploy anchors. Once the storage tanks are full (typically 20 days production), the vessel disengages from the wellhead and proceeds to a shore terminal to discharge the cargo.

Current predictions indicate that floating production systems will continue to feature prominently in the future development plans of the leading oil companies. They offer considerable cost saving benefits when compared with fixed structures and with the introduction of the diverless subsea wellhead, there is virtually no limitation to the water depth in which they can operate. They are used extensively in the Campos Basin of Brazil, the world's deepest subsea development in water depths up to 1,000 metres (3,400 feet). Floating Production Systems have also been selected for the development of the new discoveries in the Atlantic Ocean, West of Shetland.

## 6. SELF ELEVATING JACK-UPS

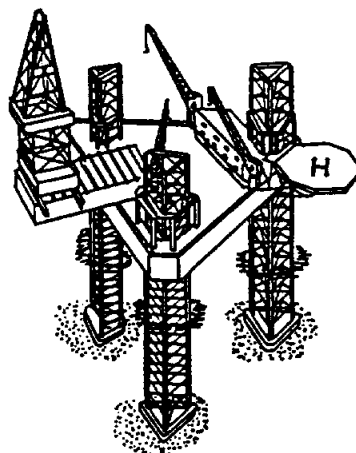
The self elevating jack-up is one of the stalwarts of the offshore industry, its origins dating back over 60 years when it could be found searching for oil in the muddy swamps of Louisiana.

The self elevating jack-up consists of a triangular, sometimes rectangular, shaped box section barge fitted with three (sometimes four) moveable legs which enable the vessel to stand on the sea bed in water depths of up to approximately 120 metres (400 feet). The shape of the vessel imposes design restrictions similar to those encountered with semi-submersible vessels which prevent the fitting of a main propulsion unit. Transportation over short distances is effected under the tow of tugs or supply boats whilst it is both quicker and safer to accommodate a jack-up on the back of a submersible heavy lift ship to undertake long sea passages. Once on location, thruster units enable the vessel to maintain position whilst the legs are lowered to the sea bed and the hull is jacked into position, clear of wave action. The base of each leg is fitted with a "spud can" which consists of a plate or dish designed to spread the load and prevent over penetration of the leg into the sea bed. High pressure jets of water or compressed air may be used to remove loose debris in the vicinity of the spud cans whilst the legs are manoeuvred into position, this process is known as "spudding in".

Jack-ups are primarily used for drilling operations but a number have been constructed to act specifically as accommodation support vessels to provide assistance to fixed installations during construction, modification or repair programmes. The jack-ups used for drilling operations fulfil two completely different roles. The majority of jack-ups are used for exploration purposes (wildcat drilling) and they lead a solitary existence searching for oil or gas in some of the remotest corners of the globe.

The other role in which jack-ups will be encountered is in the drilling of wells for permanent installations, particularly gas producing platforms such as those located in the southern sector of the North Sea. The gas production process does not require the same level of ongoing drilling activity and well modification work that is associated with the production of oil. Consequently derricks are not normally fitted to gas producing installations and all well modifications and drilling operations must be carried out by a jack-up sited alongside. The drilling derrick is fitted to rails so that it can be cantilevered into a position which provides direct access to the wellhead area.

The future of the self elevating jack-up looks assured with old rigs being replaced with designs capable of operating in ever deepening, harsh water environments. In fact the jack-up looks set to increase its share of the offshore market with a new generation of rigs designed to operate as process facilities for the development of marginal oil fields using subsea wells.



SELF ELEVATING JACK-UP

## 7. SINGLE POINT MOORING (SPM)

The single point mooring concept originated as a solution to the problem of transferring crude oil from an onshore reception facility or refinery into very large oil tankers which were physically too big to enter port. The tankers are moored to a large buoy located at some considerable distance from the coast, often several miles, the buoy itself being secured by a spread of anchors. The oil is transferred from a subsea pipeline, through a swivel connector in the buoy into loading hoses attached to the tanker, the tanker thus being free to weathervain around the buoy independent of both wind and tide.

Single point moorings of the type just described employing a tethered buoy and flexible riser are still used extensively and a number of more sophisticated designs such as the CALM (catenary anchor leg mooring) yoke and the FRAMS (flexible riser and mooring systems) have emerged to service the more specialist needs of the offshore industry. Variations on the single point mooring theme have also been developed which employ a rigid structure or riser column to convey crude oil from the sea bed to the surface. Examples of this particular breed are the SALM (single anchor leg mooring) and the ALP (articulated loading platform). Regardless of design they all attempt to achieve the same end result which is to provide a safe mooring for the loading vessel in wind speeds of 80km/hour (50 m.p.h.) and wave heights of 5.5 metres (18 feet).

A brief account of a fixed column SPM will now be given which is representative of the type used as a loading terminal by Statoil for their Statfjord B development.

This particular SPM consists of three main components:-

### i) GRAVITY BASE

The gravity base shown measures 20 x 20 x 8 metres ( 65 x 65 x 27 feet ), weighs 950 tons and contains 4,500 tons of iron ore ballast to assist the forces of gravity in keeping the column firmly rooted to the sea bed.

### ii) COLUMN

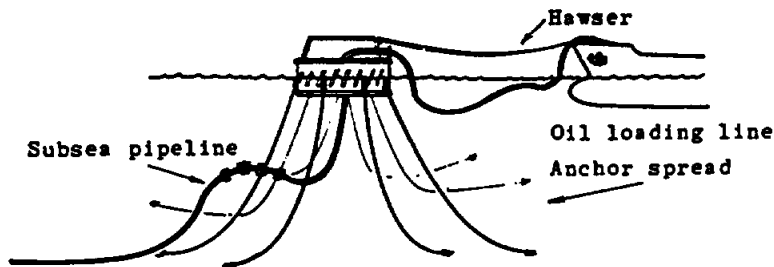
The steel column boasts dimensions equally as impressive as those of the gravity base measuring 170 metres ( 560 feet ) in height, 9 metres ( 30 feet ) in diameter and weighing 4,000 tons. To assist emplacement the column is filled with 2,400 tons of iron ore in addition to the permanent water ballast. A Cardan type articulated joint provides the means of attachment to the base a feature that also permits a degree of lateral movement. The crude oil is transferred from the manifold at the gravity base up to the rotating head by two 36 inch diameter ( 750 mm ) pipelines routed up the outside of the column.

### iii) ROTATING HEAD

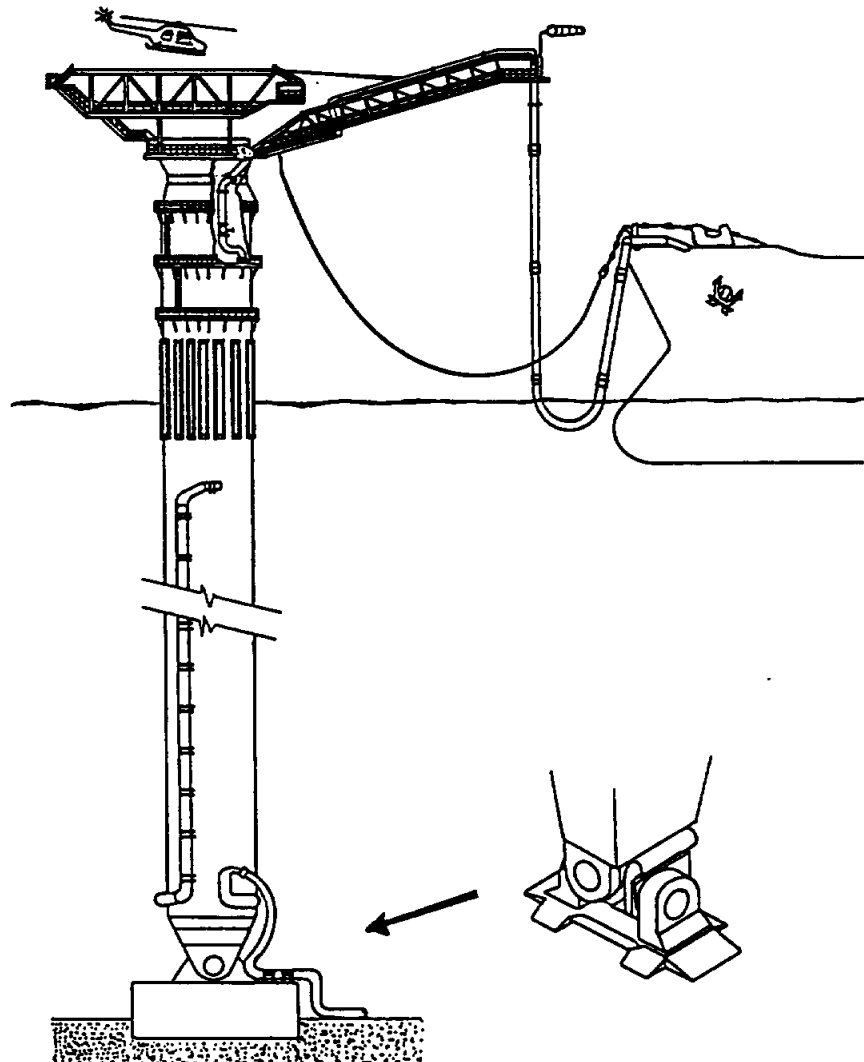
The rotating head contains the quick release mooring and loading attachments, temporary accommodation and a helideck and is designed to act as a moving pivot for a ship to rotate around under the influence of wind and tide. The oil is transferred from the column into the loading hoses through a swivel coupling at discharge rates of up to 57,000 barrels an hour (8,000 tonnes) and this particular SPM has the facility to load ships ranging in size from 80,000 to 150,000 tonnes.

Riser column SPM's such as those just described have two main applications. Connected to a subsea pipeline the riser towers provided the ideal means of loading tankers, for whilst a pipeline is certainly the most cost effective means of conveying large quantities of crude oil over long distances the

SPM enables tankers to load oil destined for global export without the inconvenience and expense of entering port. The other area where the SPM has grown in popularity in recent years is the subsea market. When a field is developed exclusively by subsea wells, the oil is normally processed by a floating production system (FPS) prior to export. The wells may be connected to the floating production system by individual flexible risers, or manifolded on the sea bed and connected by an SPM, an altogether much neater arrangement.



CALM BUOY



SINGLE POINT MOORING

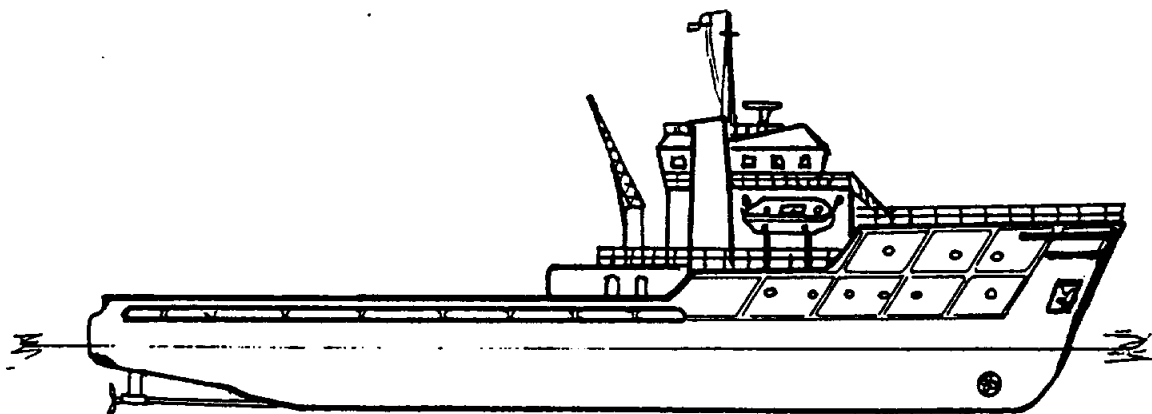
## Part 2. SUPPORT VESSELS

The photograph on page 16 gives an indication as to the variety of vessels required to ensure the continued good health of the offshore industry. Whilst appearing to have little in common with one another apart from maybe a helideck, they can loosely be divided into construction or support vessels. The larger vessels tend to be employed on the installation, maintenance and repair of subsea pipelines and fixed platforms and were introduced if not fully discussed in Part 1. The smaller vessels consist primarily of diving support (DSV), survey, supply and standby boats.

The offshore supply and standby boats deserve a special mention as they will be encountered repeatedly in almost daily attendance to the production installations and construction fleets, the DSV and survey vessels will be discussed in subsequent chapters.

### 1. THE OFFSHORE SUPPLY BOAT

The distinctive profile of the offshore supply boat cannot be confused with any other vessel. The high bow and forward accommodation are designed to withstand the severest of weather conditions and permit 360° of unrestricted vision from the wheelhouse whilst the long flat afterdeck provides an ideal platform for the stowage of containers, drill pipe and the occasional 20 ton anchor. Below decks a refrigerated cargo hold facilitates the transportation of perishable food stuffs and potable water, diesel fuel, cement and barytes are carried in purpose built tanks.



SUPPLY BOAT

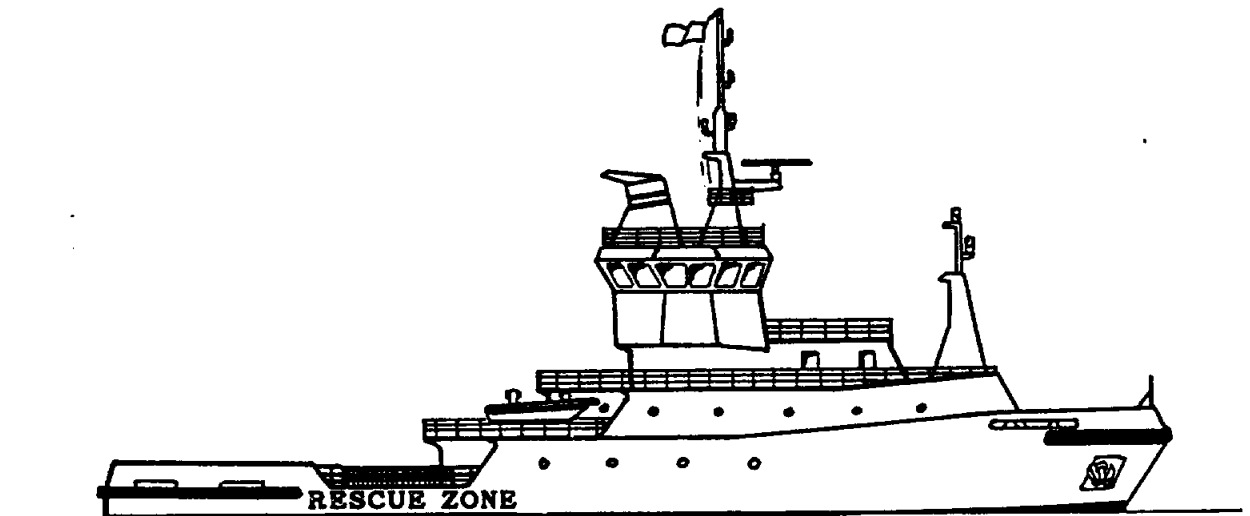
More than anything else the supply boat personifies power and manoeuvrability. A twin engine/twin propeller arrangement provides propulsive power and a degree of mechanical redundancy whilst twin rudders and bow thrusters provide the manoeuvrability. The entire operation is controlled from a wheelhouse which contains duplicate controls facing forward and aft. The helmsman has literally finger tip control over the vessel to enable him to maintain close attendance to an offshore installation whilst the stores are plucked from the after deck by the platform crane.

To ensure regular employment in a fiercely competitive market the supply boat has had to develop into a jack of all trades and in addition to the basic function of delivering stores the more modern vessels will be encountered towing rigs, handling the anchors of semi-submersible vessels and providing fixed installations with fire fighting cover during major repair programmes.

It would be true to say that the offshore industry would rapidly grind to a halt were it not for the outstanding service provided by the supply boat fleet.

## 2. STANDBY VESSELS

Statutory Instrument No. 1542, Offshore Installations (Emergency Procedures) 1976, requires that every manned offshore installation located in the UK sector of the North Sea shall have in attendance a standby vessel. This vessel must be capable of accommodating the entire complement of the installation and of providing first aid facilities.



**STANDBY BOAT**

At the present time the regulations permit one standby vessel to cover any number of installations located within a five mile radius. In practice the operators of offshore installations tend to employ a number of vessels considerably in excess of this minimum requirement. An installation will frequently employ a dedicated standby vessel when personnel are deployed in positions in which they may fall into the sea such as during underdeck scaffolding, painting and inspection programmes. In the last 15 years over 125 people have fallen into the sea of which 90 were recovered safely (these figures do not include those rescued following the Piper Alpha disaster).

The majority of the 160 strong standby fleet operating within the UK sector of the North Sea consist of converted trawlers. Unfortunately the Piper Alpha disaster of 1988 highlighted deficiencies in their operational capabilities and they were severely criticised during the Cullen Inquiry.

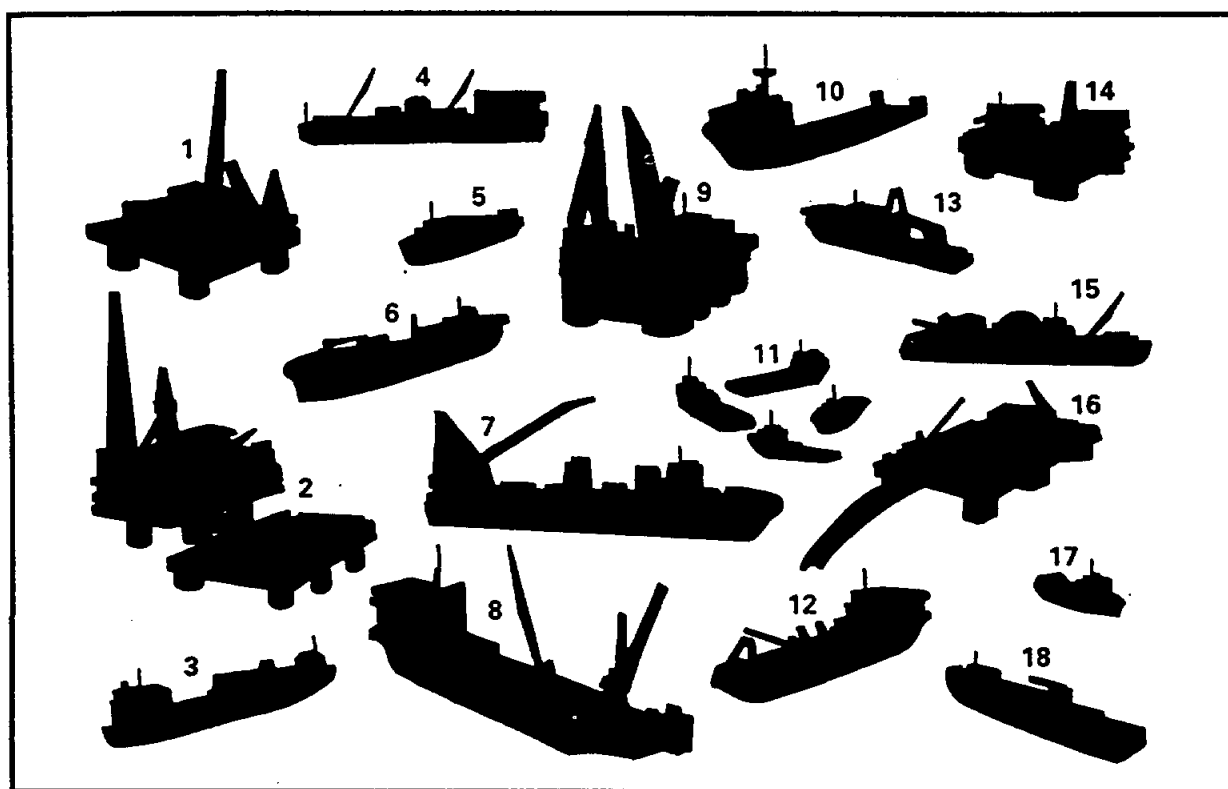
In response to the Cullen Report, the Department of Transport and the Health and Safety Executive (HSE) formulated a code of practise for standby vessels aimed primarily at improving their



## OFFSHORE STRUCTURES AND SUPPORT VESSELS

manoeuvrability and speed of response. New vessels must be at least 11 metres in length, capable of a speed of 10 knots and provide 360° unrestricted vision of the surrounding seas from the wheelhouse. They must be of either twin screw (propeller), or single screw with a 360° thruster powered propulsion unit, and be fitted with a bow thruster. They must also carry two fast rescue craft available for immediate deployment.

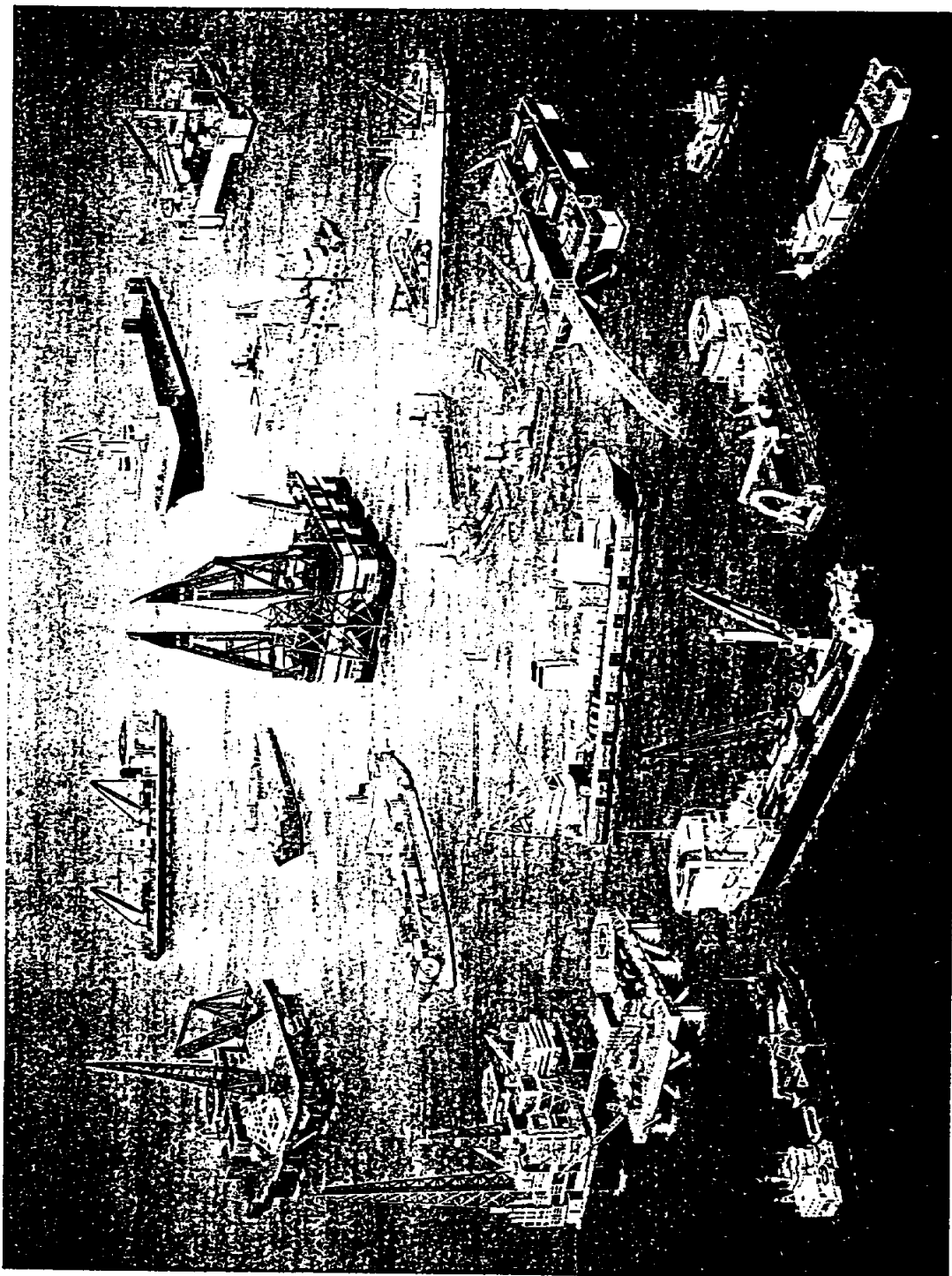
A certain latitude exists as to the acceptance of older vessels which do not comply fully with the new recommendations but the days of the converted trawler are numbered. A further review of standby vessels will take place when SI 1542 is replaced with the evacuation, escape and rescue regulations.



### OFFSHORE SUPPORT VESSELS (see overleaf)

- |   |   |    |                                      |
|---|---|----|--------------------------------------|
| 1 | Multi-functional support vessels (MSVs) | 10 | Heavy transportation vessels         |
| 2 | Accommodation units                     | 11 | Anchor handling, tug, supply vessels |
| 3 | Fallpipe dumping vessels                | 12 | Diving support vessels               |
| 4 | Pipeline bury barges                    | 13 | Well service vessels (see also 18)   |
| 5 | Seismic survey vessels                  | 14 | Multi purpose vessels (see also 1)   |
| 6 | Flexible pipelay vessels                | 15 | Reel pipelay vessels                 |
| 7 | Derrick lay barges                      | 16 | Pipelay barges                       |
| 8 | Pipelay ships                           | 17 | Standby vessels                      |
| 9 | Derrick and crane barges                | 18 | Well stimulation vessels             |

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# OFFSHORE SUPPORT VESSELS

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## ***Part 3. OFFSHORE INSTALLATIONS DESCRIPTION.***

The sketch overleaf shows a typical offshore installation. The main component parts may be described as:-

### **1 Accommodation**

The accommodation block provides a full range of hotel services designed to cater to the needs of the personnel employed in the operation and maintenance of the installation.

On new installations the accommodation may be designated as the Temporary Safe Refuge (T.S.R.) and will be designed to provide maximum protection to personnel during an emergency situation.

### **2 Wellhead Area**

The wellhead area contains the christmas trees which regulate the flow of hydrocarbon products from individual wells to the process equipment.

### **3 Process Area**

The process area contains the pressure vessels and associated equipment required to remove impurities and bi-products from the oil or gas prior to their discharge into the subsea pipeline.

### **4 Power Generation**

The majority of offshore installations are located a considerable distance from the coast and as such must be self sufficient in all aspects, including the generation of electricity. The alternators may be driven by reciprocating diesel or gas fuelled engines, or by gas turbines.

### **5 Helideck**

Helicopters provide the means by which personnel are transported to and from offshore installations and they are used as the primary means of evacuation in the event of an emergency. In UK waters, helicopters and helidecks come under the jurisdiction of the Civil Aviation Authority.

### **6 Lifeboats**

In the event of an emergency which necessitates abandonment of the installation, the lifeboats provide a means of escape to the sea in the absence of helicopter assistance.

### **7 Radio Mast**

A steel tower which accommodates communication components such as satellite and telemetry dishes.

### **8 Vent Stack - (gas producing installations only).**

Vertical, open ended discharge pipe through which process gas may be expelled to atmosphere in order to depressure and make safe the gas process equipment.

### **9 Flare Stack - (oil producing installations only).**

The flare stack provides a safe, remote location for the disposal, by burning, of unwanted gaseous hydrocarbon bi-products produced during the oil refining process.

### **10 Drilling Derrick - (normally only oil producing installations).**

The drilling derrick is used throughout the life of an installation to drill new oil wells, to drill wells for enhanced oil recovery (EOR) water and gas injection, and to carry out modification and repair operations.

## *Offshore Engineering*

### **11 Pedestal Cranes**

The cranes are used to assist in maintenance operations and to facilitate the unloading and loading of stores from supply boats.

### **12 Cellar Deck**

Lower-most deck in process area.

### **13 Spider Deck**

Walkway located above the high water line which facilitates inspection and maintenance of the jacket structure. It also provides an emergency escape route to the sea.

### **14 Jacket**

Tubular steel support structure.

### **15 Conductor Guide Frame**

Guide frames are located at regular intervals both above and below sea level to restrain the wellhead conductors against lateral movement.

### **16 Conductor**

Section of pipe extending from the sea bed to the wellhead area, the conductor supports the christmas tree and contains the piping system or casing strings which conduct oil or gas from the reservoir to the installation.

### **17 Riser**

Section of the subsea pipeline extending from the sea bed to the emergency shutdown valve (ESDV) on the installation.

### **18 Riser Clamp**

Clamp or clamps used to secure the riser to the jacket.

### **19 Caisson**

Tubular steel pipes or casings extending to a position below the lowest sea level. They may accommodate deep well pumps for fire fighting and service water facilities, or provide a disposal route for unwanted liquids and drains.

### **20 Mud Mats**

Steel plates attached to the base of each leg to prevent over penetration of jacket into a soft sea bed.

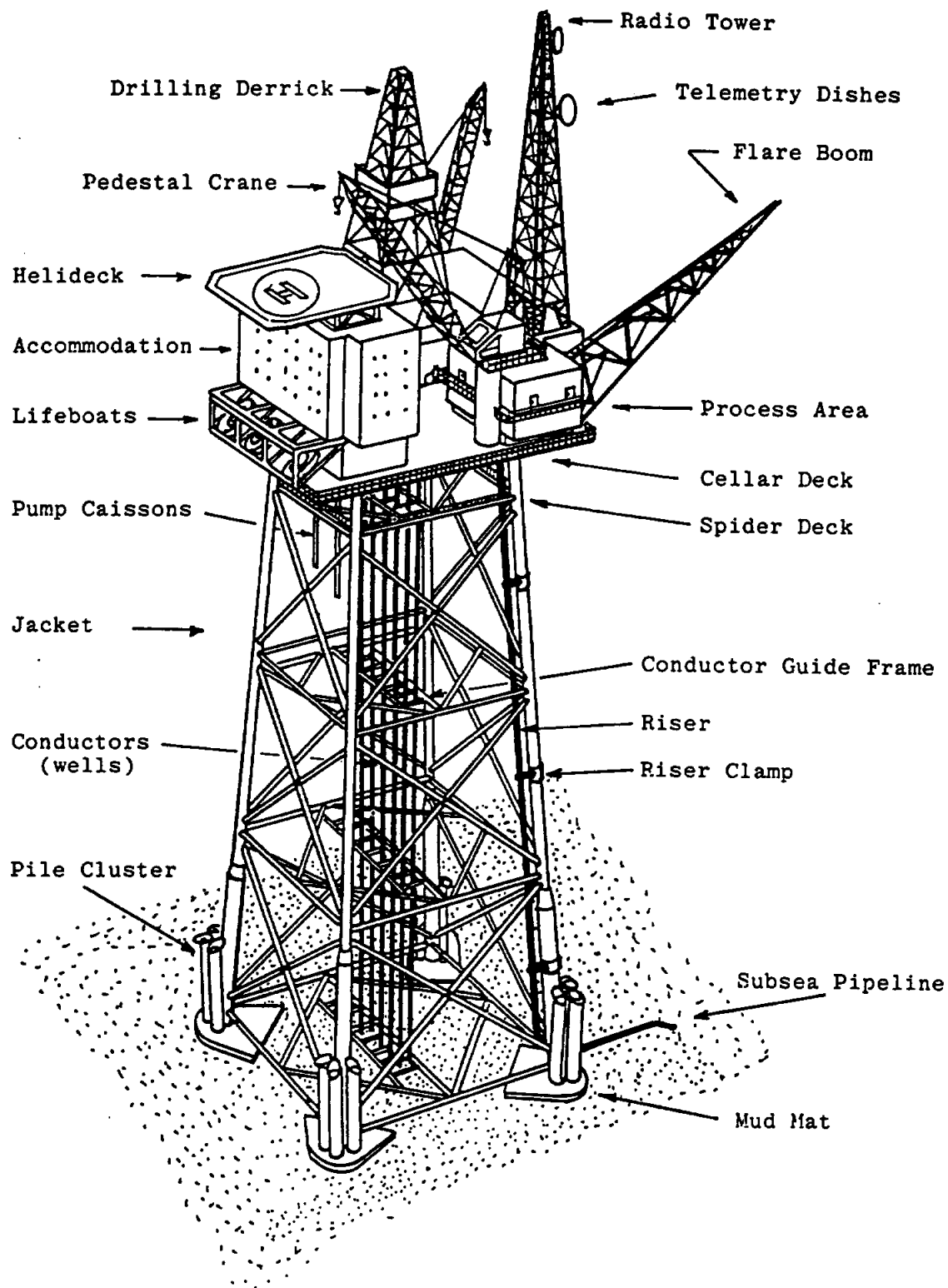
### **21 Pile Clusters**

Fitted on deep water jackets to house the foundation piles.

### **22 "J" Tubes**

Open ended "J" shaped pipe attached to the jacket structure and extending from cellar deck to sea bed. Provides protection for flexible flowlines and umbilicals emanating from subsea wells.

## OFFSHORE STRUCTURES AND SUPPORT VESSELS



**FIXED STEEL STRUCTURE**

## **Part 4. FIXED STEEL STRUCTURES-INSTALLATION.**

### **INTRODUCTION**

The North Sea represents one of the most hostile marine environments in the world and a considerable amount of specialised technology has been developed over the years to cope with the tantrums of Mother Nature. The bulk of the offshore engineering prior to 1965 was carried out in the relatively calm waters of the Gulf of Mexico and it was Gulf technology which was used to construct the early North Sea installations. In fact some of the first process modules were actually built in the U.S.A. and shipped over to the U.K. Since those early days the technology developed to cope with the North Sea's extremes of weather has elevated British offshore engineering into position as a world leader.

For the purpose of this chapter we are dealing with fixed steel structures which represent the vast majority of offshore installations. They vary considerably in size and on the UKCS (UK Continental Shelf) there is a very definite North/South divide created by the tremendous differences in water depths, weather conditions, and platform complexity. The southern sector installations stand in relatively shallow water depths of 12 to 40 metres (40 to 135 feet) and the basic nature of the gas processing equipment permits the construction of small, lightweight structures. The support structures or jackets weigh in the region of 250-1,500 tonnes and the topsides or superstructures from 1,500-10,000 tonnes.

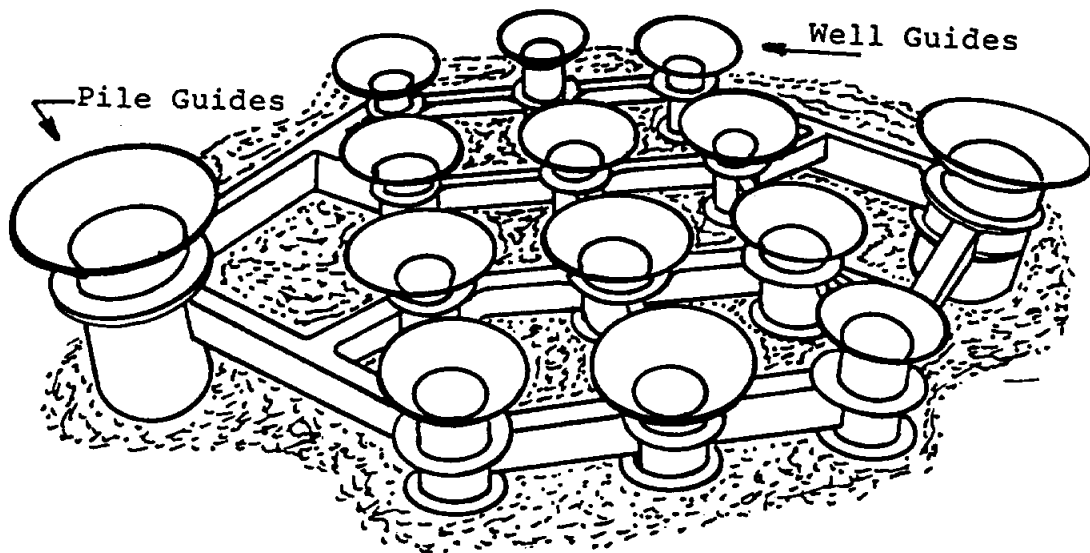
In the northern sector jacket weights tend to be in the region of 5,000-20,000 tonnes although the giant rigs installed in the boom years are much bigger. The heaviest jacket belongs to the B.P. Magnus installation which weighs 35,000 tonnes. These colossal structures are required to support topside weights of up to 40,000 tonnes in water depths of 100 to 160 metres (325 to 550 feet) and reflect the considerable quantity of process and drilling equipment required to produce and process oil.

Offshore structures are constructed on the mainland and their design must reflect how they will be installed offshore. They are assembled in building brick fashion as can be seen from the sketches.

### **1. SUB SEA TEMPLATE**

The first installation operation involves the siting of the sub sea template on the sea bed. The template is piled into the sea bed in a location considered to be the most favourable for reaching the hydrocarbon deposits. The main objective of the template is to provide a guide frame through which wells can be drilled prior to the arrival of the jacket. Drilling wells takes a considerable amount of time and it is advantageous to enlist the services of a drilling vessel to pre-drill some, or all of the wells, whilst the jacket is under construction on the mainland.

In addition to well guides, guides are provided in the template to assist in the accurate positioning of the jacket over the template. Sub sea templates are unlikely to be deemed necessary on small installations situated in shallow waters.



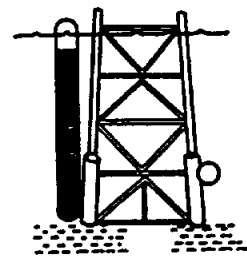
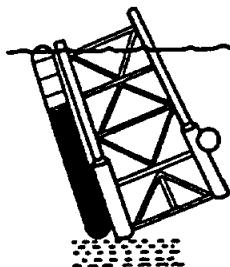
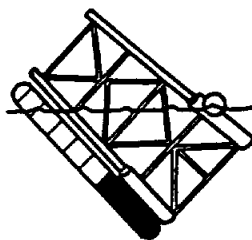
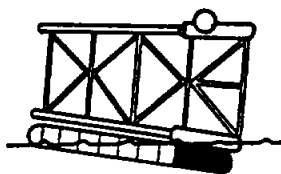
SUBSEA TEMPLATE

## 2. JACKET

Tubular steel jackets are completely fabricated onshore prior to transportation to site by raft type dumb barge. The smaller jackets may be lifted in place by a floating crane whilst the largest jackets employ flotation devices to assist in their installation. The flotation devices are sequentially flooded to enable the jacket to sink slowly into its final resting place. Once located on the sea bed the jackets are secured by foundation piles.

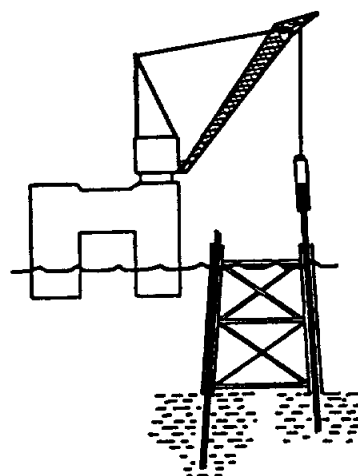
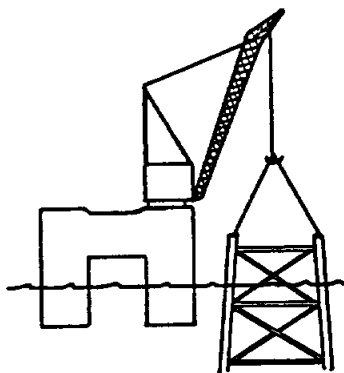
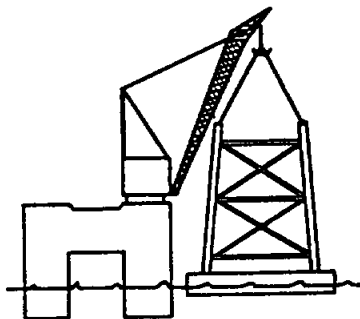
Jacket size dictates the method of pile installation as can be seen from the sketches. On the smaller jackets tubular piles are driven through the legs to a pre-determined depth of 30-50 metres (100 to 165 feet), or inserted into pre-drilled holes when the formation resists conventional piling techniques. The piles are located centrally within the leg by means of spacers attached to the piles. On completion of piling the pile is cut level with the jacket and it may be cemented in place (grouted), swaged or welded. This arrangement has been used to secure jackets in water depths of up to 100 metres (335 feet).

The immense size of the deep water jackets makes piling through the legs impractical so a pile cluster is fitted to the base of each leg. The piles can then be driven through the cluster guides to the required depth of 60-90 metres (200 to 300 feet) before being grouted into position. Over 6,000 tonnes of piles were used to secure the BP Magnus jacket.

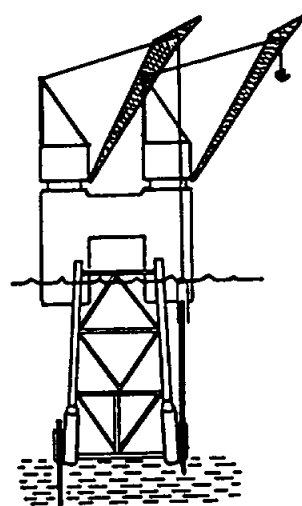
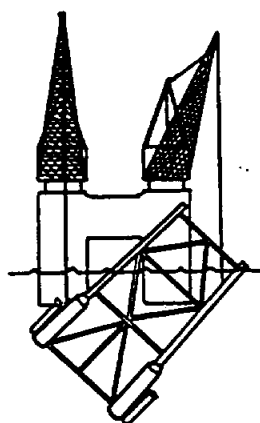
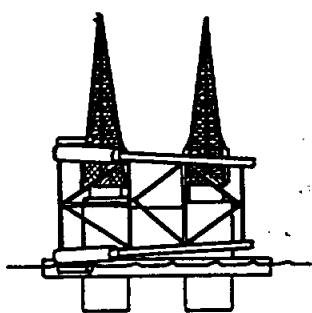


Deep water launch

Shallow water lift



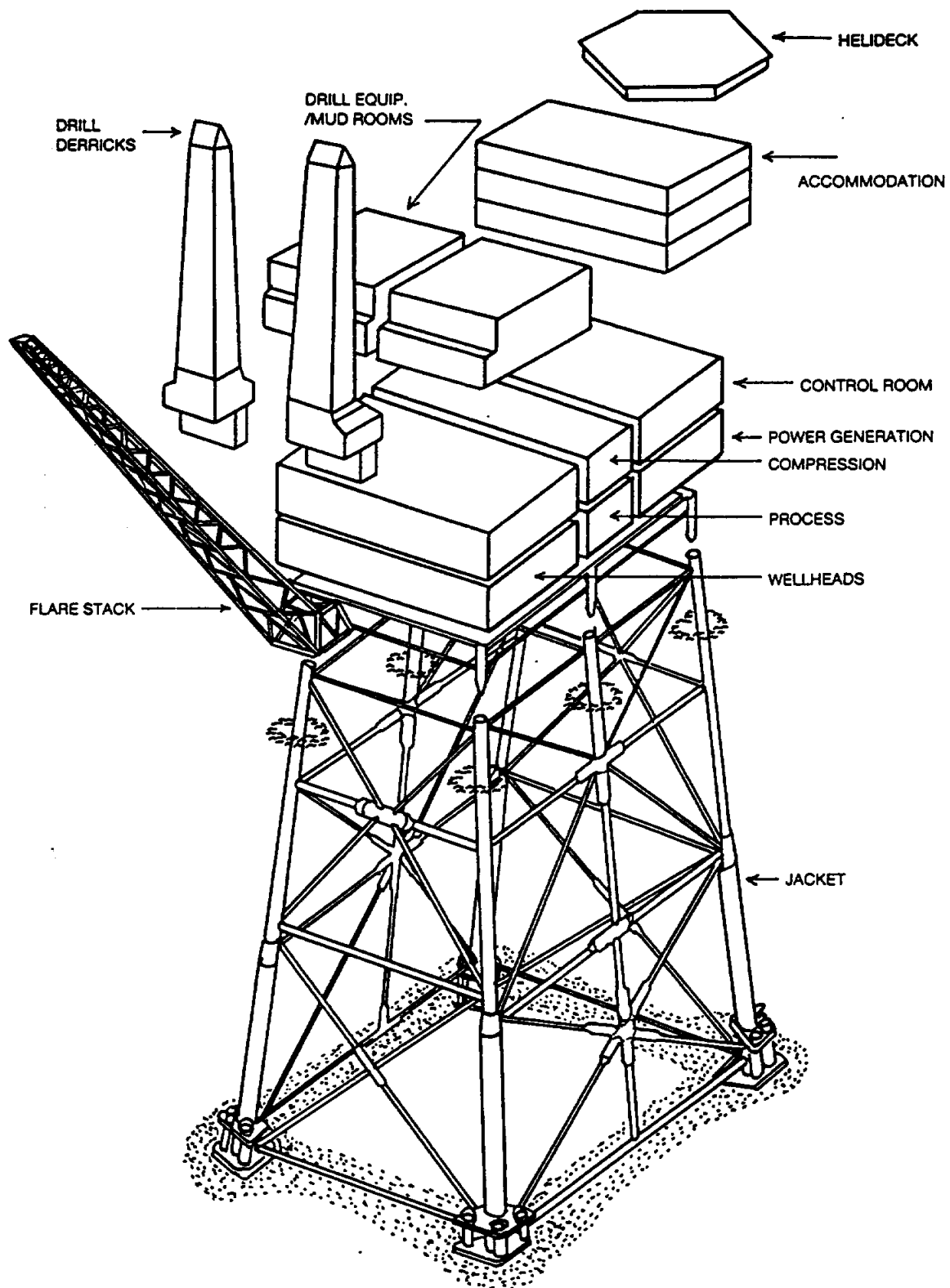
Moderate water lift



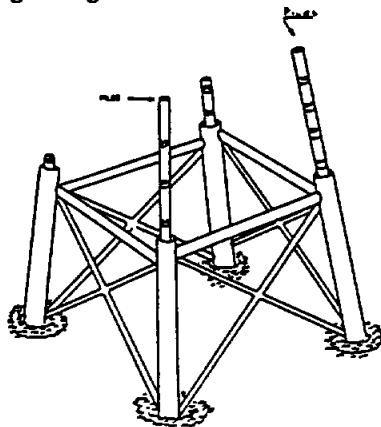
## JACKET INSTALLATION



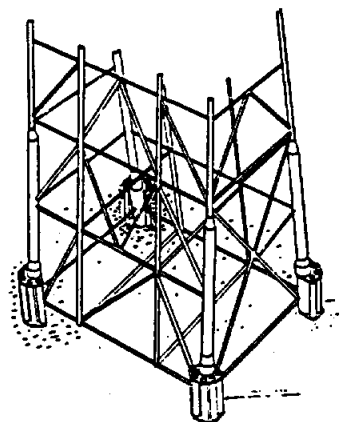
## OFFSHORE STRUCTURES AND SUPPORT VESSELS



LIFTING PLAN



**PILING - THROUGH JACKET**



**PILE CLUSTERS - DEEP WATER**

An alternative to piling has recently been developed by Statoil and used to secure the Europipe riser jacket. The jacket legs sit within skirted mud mats, essentially large inverted buckets, 12 metres (40 feet) in diameter and 6 metres (20 feet) deep which penetrate the sea bed under the weight of the jacket, the jacket legs being filled with water ballast during installation to assist the penetration process. Suction provides further penetration prior to the addition of 2,200 tonnes of permanent grout ballast which was poured into the top of the buckets. This novel concept offers considerable savings on installation time and costs and is sure to be more widely used in the future.

### 3. TOPSIDE INSTALLATION

The topside weight of an installation may be as low as 1,500 tonnes for an unmanned installation in the southern North Sea or it may be as high as 35,000 tonnes for one of the northern sector monsters. Whilst a floating crane can lift 1,500 tonnes onto a jacket, it is obviously impossible to lift 35,000 tonnes in a single lift. Consequently, the larger platforms must be constructed within the constraints of the lifting facilities available, which to date is approximately 14,000 tonnes. This entails constructing the topsides in liftable packages which can be installed and secured one at a time, the world record lift being the Piper Bravo at 10,750 tonnes.

The heavy lift cranes used for installing rigs are mounted on semi-submersible barges which have been purpose built for offshore work. These enormous catamaran type vessels with deck capacities of upto 11,500 tonnes often accommodate the smaller topside modules as deck cargo for transportation to the site. Where this is not practical the modules are loaded onto flat top barges and towed to their destination.

To assist installation the modules and jackets are fitted with male and female type location devices referred to as stab ins or bucket guides, examples of which can be seen in the installation photographs.

Assembly of an offshore installation in this manner creates tremendous competition within the module fabrication industry. Until recently a module destined for service in the UK sector of the North Sea would have been constructed almost entirely in the UK. However, the advent of the common market has seen the emergence of the "Euro rig", which can contain a collection of modules fabricated in the UK, Spain, France, Italy and Portugal. British industry must ensure that this trade is not one-way!

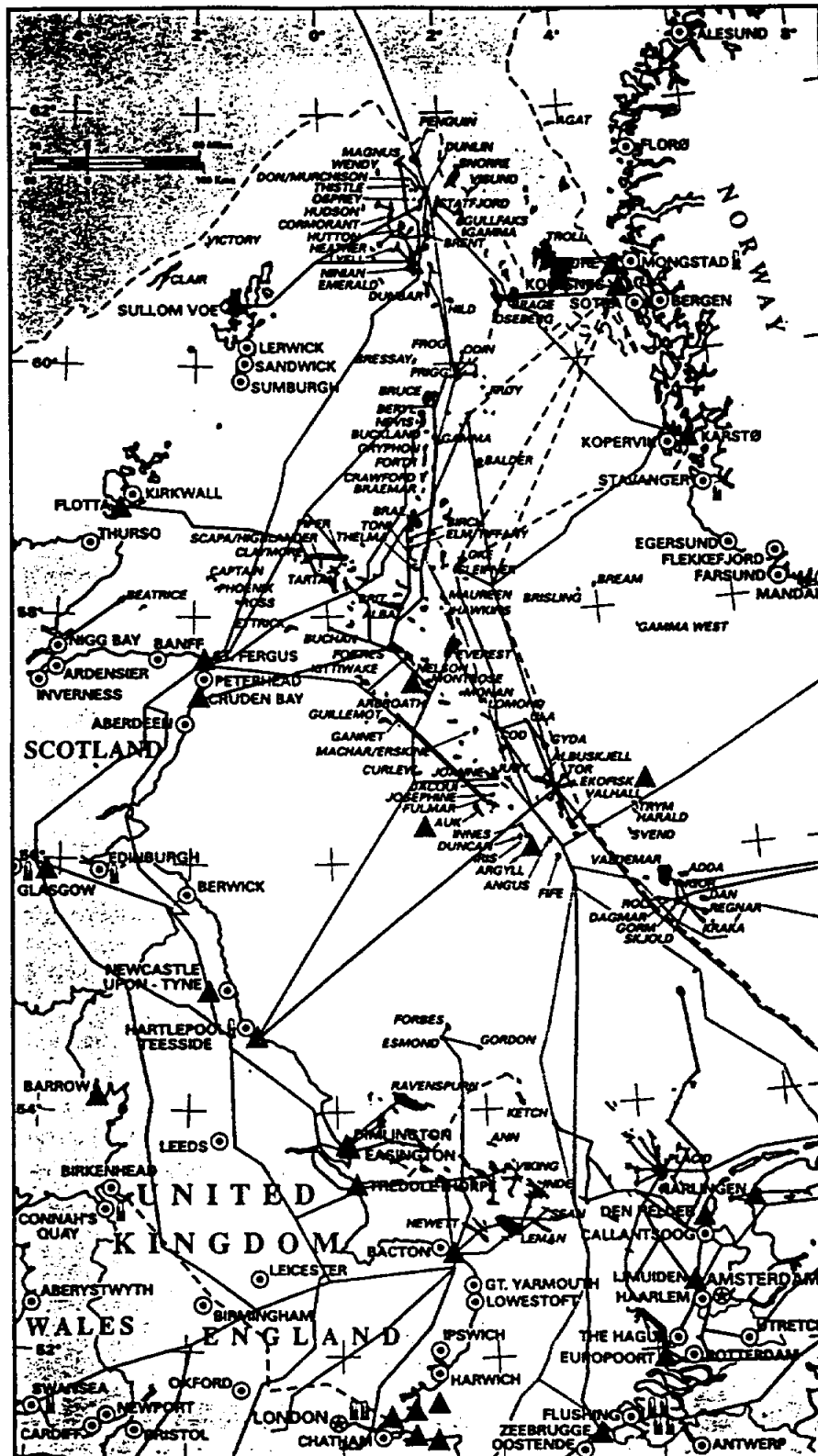
## **Chapter Two**

### **THE NORTH SEA**

**PART 1. HISTORY**

**PART 2. LEGISLATION**

# North Sea



## NORTH SEA U.K. OIL & GAS FIELDS

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## **Part 1 THE NORTH SEA THE STORY SO FAR**

The object of this chapter is to provide the reader with a brief history of the North Sea oil and gas industry and to place the UK's involvement in European and world wide hydrocarbon production into perspective.

The UK Offshore gas industry dates back to 1963 when exploration of the southern North Sea commenced following the discovery of a large onshore gas field at Groningen in Holland. The first offshore gas field, the West Sole situated off the Humber Estuary, was discovered in 1965 and this was quickly followed by the Leman gas field approximately 50 miles off the coast of East Anglia. For many years the Leman field was the largest offshore gas field in the world and it is still one of the largest producers of gas for the UK, supporting 33 installations.

Today there are over 50 gas producing fields located in the southern North Sea supporting nearly 100 fixed installations which produce 150 million cubic metres of gas a day, making the U.K. by far the largest producer of offshore gas in Europe. However, as recently as 1990 the industry was regarded as being in decline with production figures predicted to be halved by the year 2000. There has since been a dramatic about turn initiated largely by the privatisation of British Gas which has seen a return to record levels of output.

The offshore oil industry appears to portray a similar picture of boom and bust. It was not until 1969 that the colossal Ekofisk oil field was discovered in the Norwegian sector of the North Sea and it was a further two years before it went into production. The Argyll field heralded the start of oil production from the U.K. sector and the subsequent development of over 85 oil and condensate fields elevated Britain into the position of leading European oil producer. Today, Britain shares this position with Norway, both countries producing in the region of 2 million barrels of oil a day. However, like the gas, oil production was in decline having peaked in 1985 but the resurgence in field development activities has once again seen production running at record levels.

The mini boom currently being experienced by the offshore industry is supported by the figures for proven reserves which show that only one third of the UK's reserves of 31 billion barrels of oil and 3.6 trillion cubic metres of gas have been produced to date. Expenditure in the North Sea is predicted to equal the cost of constructing a Channel tunnel every year until the turn of the century. Potential exists for the development of a further 150 oilfields and 30 gas fields which will require up to 55 fixed platforms, 30 floating production systems and 60 subsea installations in addition to the 450 fixed structures already operating in north European waters. This will ensure the survival of the offshore industry for at least another 35 years.

Oil field size is defined in terms of millions of barrels (mn bbls) of recoverable oil. The daily production figures are quoted in thousands of barrels a day (bbls/d) and give an indication as to the size of the platform required to exploit a particular reservoir.

Gas field reserves are defined in billions of cubic metres (bcm) with daily output figures measured in millions of cubic metres a day (mcm /d).

The oil and gas fields currently under development tend to be much smaller than those that represent the golden years of the offshore industry. The Norwegian Troll field may appear to contradict

this statement as it is nearly four times the size of the original Leman Field. However, the field was actually discovered in 1974 but development was delayed due to the difficulty in tapping the gas bearing formations. Advances in drilling technology have since permitted full exploitation of the fields reserves.

A more realistic picture of current development trends within the UK sector may be obtained by considering the reserves contained within Amerada Hess's Scott field and British Petroleum's Bruce field. The Scott is destined to be the largest oil field developed in the 1990's accounting for nearly 10% of the UK's output. It contains estimated oil reserves of 450 mn bbls which will provide a daily production output of 180,000 bbls. The field also contains significant quantities of gas and LNG (liquified natural gas). The Bruce is the largest gas field under development with estimated reserves of 74 bcm of gas and significant quantities of oil.

The Bruce and Scott fields are slightly unusual in that they contain large quantities of both oil and gas. Previously, most of the gas fields have been located in the southern sector of the North Sea with all the oil in the north. It should be noted that the oil and gas exist in separate wells in the Bruce and Scott fields and should not be confused with the associated gas released during the oil production process.

It is worth noting at this point that whilst the Bruce field is operated by B.P. there are numerous other oil companies listed as licensees or joint owners. The other licensees are Elf (31.5%), Hamilton Brothers (16%), Total (11%), Ultramar (3.75%) and Renown Petroleum (0.75%). This form of sharing the development and operational costs, and subsequent profits is referred to as partnering and is used extensively all over the world on virtually every development.

The fields currently under development in the UK may appear to be small change when compared to the Leman and Forties fields that heralded the birth of the oil and gas industries but they compare favourably with field sizes elsewhere in the world. For instance, the Mars field is the largest find in the Gulf of Mexico for 20 years and at 500 million barrels is comparable with the previously mentioned Scott field. They represent the bread and butter side of the offshore industry and are far more numerous than the monster discoveries that represent the icing on the cake.

Both Britain and Norway rely heavily on the oil and gas industries to maintain acceptable balance of trade figures. However, to put the industry into perspective we must appreciate that the North Sea contains less than 5% of proven world hydrocarbon reserves. Saudi Arabia, Iran, Iraq and Kuwait own over 50% of existing reserves and the Commonwealth of Independent States (the CIS, formerly USSR) also possessing huge reserves of oil and gas. The Schtockmanskoye field has estimated reserves of 2,400 billion cubic metres and the Rusanovskaya field may contain as much as 8,000 billion cubic metres of gas.

Whilst the UK does not possess reserves which enable it to compete with the CIS and the OPEC nations, what it can provide is the technology and expertise developed from 25 years experience in the North Sea. Technology and expertise that is set to be further extended as the offshore engineers pick up the gauntlet and accept the challenges of the Atlantic Ocean frontier provinces, West of Shetland.

## THE NORTH SEA

The following tables have been prepared as a form of ready reckoner so that future developments within the oil and gas industry can be compared with the established milestones of the preceding 25 years.

### NORTH SEA GAS FIELDS

Field/Operator	YEAR	RESERVES x bcm		PRODUCTION x mcm/day	
		Original	Present	Peak	Current
A. MAJOR FIELDS					
i. UK					
LEMAN Amoco/Shell	1969	330	85	55	13
MORECAMBE BAY British Gas	1985	140	120	33	24
INDEFATIGABLE Amoco/Shell	1971	134	32	20	8
HEWETT Phillips	1969	115	20	23	6
BRUCE British Petroleum	1993	74	74	15	15
ii. NORWAY					
EKOFISK Phillips	1971	285	148	46	29
FRIGG Elf	1977	176	6	77	18
B. SECONDARY FIELDS (average size)					
i. UK					
2 in number	*	85	*	*	4
6 in number	*	30	*	*	3
10 in number	*	10	*	*	4
ii. NORWAY					
7 in number	*	46	*	*	8
5 in number	*	16	*	*	2
3 in number	*	3	*	*	0.5
C. FIELDS UNDER DEVELOPMENT (UK) (average size)					
2 in number	*	42	*	Expected Production 10	*
5 in number	*	13	*	4.5	*

## NORTH SEA OIL FIELDS

Field/Operator	YEAR	RESERVES x mnbbbls Original	Present	PRODUCTION x bbls/day Peak	Current
A. MAJOR FIELDS					
i. UK					
FORTIES British Petroleum	1975	2,470	450	525,000	120,000
BRENT Shell	1976	1,800	600	410,000	224,000
NINIAN Chevron	1978	1,100	300	315,000	115,000
BERYL Mobil	1976	835	440	115,000	95,000
MAGNUS British Petroleum	1983	665	365	163,000	138,000
SCOTT	1994	450	450	180,000	180,000
ii. NORWAY					
STATJFORD Statoil	1979	3,240	1,500	710,000	700,000
EKOFISK Phillips	1971	1,700	1,095	300,000	149,000
OSEBERG Norsk-Hydro	1988	1,460	1,300	400,000	310,000
GULFAKS Statoil	1986	1,321	1,200	490,000	264,000
B. SECONDARY FIELDS (average size)					
i. UK					
6 in number	*	413	*	*	60,000
10 in number	*	165	*	*	45,000
15 in number	*	70	*	*	15,000
3 in number	*	12	*	*	4,000
ii. NORWAY					
4 in number	*	370	*	*	52,000
2 in number	*	180	*	*	22,000
5 in number	*	37	*	*	5,000
C. FIELDS UNDER DEVELOPMENT (UK) (average size)				Expected Production	
3 in number	*	300	*	100,000	*
5 in number	*	140	*	60,000	*
5 in number	*	40	*	20,000	*



## PETROLEUM STATISTICS

### WORLD PROVEN CRUDE OIL AND GAS RESERVES BY GEOGRAPHIC LOCATION:

	OIL		GAS	
	(thousand tonnes)		(trillion cubic metres)	
WORLD TOTAL	137,474,595	100.00%	138.9	100.00%
of which:				
Middle East	90,721,337	65.99%	43.1	31.00%
Latin America	16,960,366	12.34%	7.3	5.20%
Africa	8,475,181	6.16%	9.7	7.00%
Eastern Europe	8,108,614	5.90%	56.6	41.00%
Far East & Australasia	6,105,798	4.44%	9.5	6.70%
North America	5,000,000	3.64%	7.4	5.30%
Western Europe	2,103,298	1.53%	5.3	3.80%

Total world oil demand 9.2 million tonnes a day (3,366 million tonnes a year).

Life expectancy of existing oil reserves approximately 40 years.

Note: 1 billion = one thousand million ( $10^9$ )

1 trillion = one thousand billion ( $10^{12}$ )

### WORLD'S TOP TEN

#### OIL RESERVES (1,000 tonnes)

Total World	137,474,595	100.0%
1. Saudia Arabia	35,320,822	25.7%
2. Iraq	13,698,630	10.0%
3. Kuwait	12,876,712	9.4%
4. Iran	12,720,547	9.3%
5. Abu Dhabi	12,630,136	9.2%
6. Venezuela	8,582,192	6.2%
7. CIS	7,808,219	5.7%
8. Mexico	7,027,123	5.1%
9. USA	4,100,000	3.0%
10. China	3,287,671	2.4%
Others	19,422,543	14.1%
(UK	2,075,000	1.5%)

#### OIL PRODUCTION (1,000 tonnes)

Total World	3,167,952	100.0%
1. CIS	450,241	14.2%
2. Saudia Arabia	427,900	13.5%
3. USA	416,000	13.2%
4. Iran	172,000	5.4%
5. Mexico	154,900	4.9%
6. China	142,000	4.5%
7. Venezuela	129,000	4.1%
8. Norway	106,600	3.1%
9. Canada	98,200	3.1%
10. UK	94,200	3.0%
Others	976,111	30.8%

### GAS RESERVES (billion cu.mtr)

Total World	138,278	100.0%
1.CIS	54,975	39.8%
2.Iran	19,790	14.3%
3.Qatar	6,425	4.6%
4.Abu Dhabi	5,332	3.9%
5.Saudi Arabia	5,168	3.7%
6.USA	4,728	3.4%
7.Algeria	3,623	2.6%
8.Venezuela	3,580	2.6%
9.Nigeria	3,396	2.5%
10.Iraq	3,099	2.2%
Others	28,157	20.4%
(UK)	1,915	1.4%

### GAS PRODUCTION (billion cu.mtr)

Total World	2,157.0	100.0%
1.CIS	787.6	36.5%
2.USA	526.9	24.2%
3.Canada	143.0	6.6%
4.Netherlands	82.3	3.8%
5.UK	53.5	2.5%
6.Algeria	52.0	2.4%
7.Saudia Arabia	48.3	2.2%
8.Indonesia	37.1	1.7%
9.Mexico	32.8	1.5%
10.Iran	26.6	1.2%
Others	367.2	17.0%

Note: The figures quoted above are for the year ending 1993. Whilst the figures will vary from year to year it is unlikely that table positions will change significantly and they will thus provide a clear indication of the general order of the main contenders.

### FACTS AND FIGURES PERTAINING TO THE UK OIL AND GAS INDUSTRY.

1 Tonne = 7.5 barrels (crude oil).

1 cubic metre = 35.31 cubic feet.

Current world oil demand 66.4 million barrels a day.

Average UK oil production 2.3 million barrels a day.

Total UK oil production 94,200,000 tonnes a year.

Total UK oil exports 54,388,000 tonnes a year.

Total UK oil imports 47,144,000 tonnes a year.

UK gas production 152 million cubic metres a day.

Annual UK oil and gas revenue £12.3 billion pounds (based on £82 tonne).

Oil production costs from North Sea fields \$4 to \$6 barrel.

### NORTH SEA CRUDE OIL PRICES

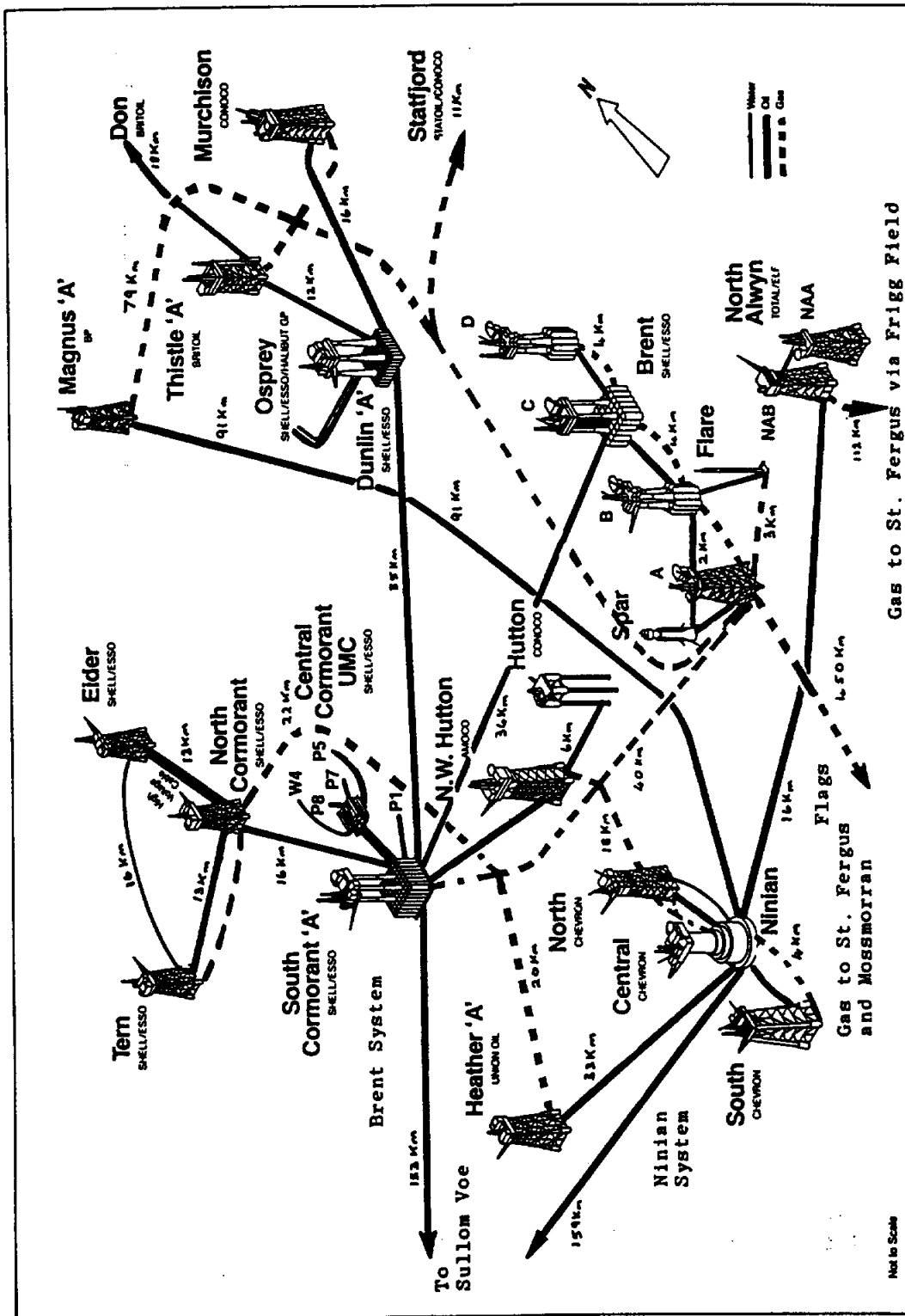
(average per year in \$US per barrel)

1979	18.0	1984	28.6	1989	18.6
1980	34.0	1985	27.5	1990	23.7
1981	35.8	1986	14.2	1991	19.6
1982	32.8	1987	18.5	1992	19.4
1983	29.5	1988	15.2	1993	16.9

### NORTH SEA GAS PRICES

Traditionally, North Sea gas prices have not fluctuated as dramatically as oil prices because of the long term contracts signed between the Operators and British Gas. Over the last few years the Operators have received approximately 20 pence per Therm for the gas, a figure which equates to £70,000 per million cubic metres, or £2,000 per million cubic feet of gas. The full effects of the denationalization of the industry have yet to be felt.

Whilst every effort has been taken to ensure the accuracy of the figures reproduced in this chapter and indeed the book as a whole it should be noted that figures quoted by the oil and gas industries are notoriously inconsistent and vary by as much as 200%. As an example, in spite of the sophisticated measuring equipment available the UK proven oil reserves are ambiguously quoted as being somewhere between 610 and 2075 million tonnes. Gas reserves are similarly ambiguously quoted as being somewhere between 630 and 1915 billion cubic metres. However, these results will provide a basis for general comparisons.



**NORTHERN NORTH SEA PIPELINE SYSTEMS**  
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## **OIL AND GAS DISTRIBUTION**

If the map for onshore and offshore oil and gas distribution is studied, a complex picture involving several thousand kilometres of pipeline emerges. It is estimated that the U.K.'s onshore gas distribution network contains over 5,000 km (3,125 miles) of main trunk line, whilst the combined oil and gas subsea pipeline systems in the North Sea amount to over 8,000 km (5,000 miles) with almost 1,000 km (625 miles) of new pipeline being added each year.

In the UK the entire onshore gas distribution system is owned and operated by British Gas but the situation prevailing with offshore oil and gas pipelines is far more complex. The colossal cost of installing a subsea pipeline has created a situation whereby companies lease space from one another, or share the construction costs. This approach minimizes capital investment and ensures that the pipeline operates at maximum capacity and hence profitability. These arrangements are particularly beneficial to the northern sector installations which frequently require two subsea pipelines, one for the transportation of oil and one for gas.

### **i) OIL DISTRIBUTION**

The U.K. is currently the tenth largest producer of oil in the world and it is all produced from the northern sector of the North Sea, an area also responsible for supplying 15% of the U.K.'s gas. The gas is produced as a bi-product of oil production and whilst it is a valuable commodity its existence considerably complicates the oil distribution process as can be seen from the map of the Northern North Sea pipeline development.

The production of oil does not suffer from the same extremes of seasonal demand that affects the gas industry and because the production of associated gas is tied to the production of oil, the quantities of gas produced during the summer months frequently exceed demand. Traditionally the excess gas was simply burnt off at the flare stack but Government legislation has since deemed this practice as being environmentally unacceptable. The problem was eventually solved by the conversion of part of the ageing British Gas Rough field into a storage facility. During the summer months the excess gas is pumped into the reservoir for recovery at a later date.

An examination of the main distribution map will show that the majority of offshore pipe lines terminate at St.Fergus in Scotland, Flotta in the Orkneys and Sullom Voe in the Shetlands with Teeside receiving oil and condensate direct from the Norwegian Ekofisk development. Whilst the U.K. is self sufficient in oil in terms of quantity a thriving import/export industry exists in order to obtain the different grades of crude required for blending purposes. Sullom Voe and Flotta operate as major refining and redistribution centres, the deep waters surrounding the Islands providing natural berths for the supertankers used to transport oil to world wide destinations.

### **ii) GAS DISTRIBUTION**

Whilst the U.K. is self sufficient in gas and likely to remain so until at least the year 2000, it imports approximately 15% of the gas consumed each year from Norway. One can only assume that there are sound commercial reasons for this trade in gas particularly since British Gas have recently signed a contract to export gas to Holland.

Gas consumption in the U.K. is split fairly evenly between domestic and industrial usage and the demand from summer to winter varies tremendously. To accommodate large fluctuations in demand British Gas use underground reservoirs located onshore in North Humberside and offshore in the Rough field near Easington. Gas is pumped underground during the summer months and recovered during periods of peak consumption in the winter.

## THE NORTH SEA

Nearly 85% of the gas produced in the U.K. originates from the southern sector of the North Sea and the production and distribution processes could not be more straightforward, particularly when compared with the complexity of the oil distribution network. The smaller offshore installations supply gas to infield terminal platforms or gathering stations which compress the gas for onward transmission to onshore reception facilities at Bacton in Norfolk, Theddlethorpe in Lincolnshire and Easington in Humberside. The compression platforms ensure that the gas is delivered to British Gas at a pressure in excess of 1125 psig (72 bar), the operating pressure of the national grid.

Prior to sale the gas requires very little in the way of preparation. The calorific value is checked and the characteristic "gas" smell is added to the naturally occurring odourless gas to assist the public in the detection of leaks.

Looking further afield, the European gas industry is experiencing a period of growth unseen since the early days of exploration. Norway is in the enviable position of owning some of the largest oil and gas fields in the North Sea and looks set to become the major European producer of both products by the year 2000. Prior to the discovery of oil and gas Norway was self sufficient in hydro-electric power and with a population of only 4 million people there exists an unrivalled opportunity for exporting energy.

Until recently the European Community (EC) restricted both the carriage of gas from one country to another, and its use for the generation of electricity. The relaxation of these restrictions has led to a tremendous growth in the construction of gas fired powered stations and permitted Norway to export to countries as far apart as Spain and Italy making gas a truly cosmopolitan commodity.

## **Part 2. LEGISLATION AND CERTIFICATION**

### **INTRODUCTION**

The offshore industry in the UK is a relative newcomer to the industrial scene especially when compared with the likes of the steel, mining and shipbuilding industries which date back to the days of the industrial revolution and beyond. For all that, the large sums of money invested and the potentially huge returns have ensured that the offshore industry has maintained a high public profile, particularly when so many traditional sources of engineering are in decline.

In terms of legislation, the offshore industry started with a clean sheet and a golden opportunity to develop regulations specific to the requirements of what is a very specialised industry. In practice the industry has suffered at the hands of more than one master and produced disjointed, conflicting regulations mainly in response to disasters involving considerable loss of life, such as the destruction of the Piper Alpha installation in 1988.

To fully understand the structure of offshore legislation we must consider the current situation, and the events of the previous 25 years. The chapter has been sub-divided into 3 sections in an attempt to clarify the situation.

### **1 LEGISLATION**

- 1.1 Mineral Workings Act (MWA) 1971.
- 1.2 Health and Safety at Work Act (HSWA) 1974.
- 1.3 Cullen Inquiry.
- 1.4 Division of Legislative Responsibility.
- 1.5 Safety Care Regulations.

### **2 CERTIFICATION**

- 2.1 SI 289 - Construction and Survey Regulations.
- 2.2 Certifying Authorities.
- 2.3 Certificate of Fitness (C of F).
- 2.4 Annual/Major Surveys.

### **3 ASSOCIATED INFORMATION**

- 3.1 Correspondence - H.S.E.
- 3.2 Statutory Instruments.
- 3.3 UKOOA.

## 1. LEGISLATION

The first significant offshore industry legislation came as a result of the 1958 Geneva Convention on the Continental Shelf which recognised the right of countries to exploit the natural resources within their coastal waters. The territorial boundaries agreed for the purposes of exploration can be seen on the field development map.

The UK Government ratified the 1958 Convention agreements and incorporated them in domestic law by passing the Continental Shelf Act (CSA) of 1964.

The Geneva Convention and CSA may be regarded as legislation pertaining to property. Legislation pertaining to the safety of offshore installations and their personnel followed in 1971 with the introduction of the Mineral Workings (Offshore Installations) Act.

### 1.1 MINERAL WORKINGS (OFFSHORE INSTALLATIONS) ACT 1971 (MWA)

The MWA was enacted as a consequence of the loss of the Sea Gem drilling jackup in 1965 and marked the start of certification regulations for offshore structures.

The MWA empowered the Secretary of State for Energy to ensure that offshore installations were certified by such persons and in such a manner that they would comply with, and remain fit for their intended purpose.

To comply with the certification requirements of the MWA, the Secretary of State for Energy passed the Offshore Installations (Construction and Survey) Regulations of 1974, known as Statutory Instrument No. 289. The Secretary of State discharged his responsibilities for the enforcement of SI 289 through the Petroleum Engineering Division (PED), a newly formed department within the Department of Energy.

At that time the PED operated a Safety Directorate consisting of six departments or branches which dealt with every conceivable aspect of the offshore industry. It was the duty of one such branch to monitor the performance of the independent Certifying Authorities who had been delegated the responsibility of applying and enforcing the regulations relating to SI 289.

The Mineral Workings Act provided ample scope for the development of legislation which reflected the specialist needs of the offshore industry. The Construction and Survey Regulations of 1974 were followed by the Offshore Installations (Operational Safety Health and Welfare) Regulations 1976, Statutory Instrument No. 1019. However, these Regulations appeared to conflict with the Health and Safety at Work Act (HSWA) introduced in 1974 and created an air of confusion that would persist for nearly 15 years.

### 1.2 HEALTH AND SAFETY AT WORK ACT (HSWA) 1974

The HSWA of 1974 marked a transformation in the approach to safety at work inasmuch as it made the individual more responsible for his or her safety and the safety of their working environment. It attempted to remove the considerable burden created by excessive and ineffective legislation.

The HSWA empowered the Secretary of State for Employment to provide for the occupational health, safety and welfare of individuals at their place of work. The Secretary of State created the Health and Safety Committee (HSC) whose function was to formulate policies and regulations pertaining to the HSWA. Policing of the regulations would be carried out by inspectors of the newly formed Health and Safety Executive (HSE), a body responsible to the HSC.

Initially the HSWA was not applicable to offshore workers. However, in 1977 the Prime Minister dictated that the Act would be extended to include territorial waters, and thus offshore installations. The Secretary of State for Energy would be made responsible for offshore safety. This responsibility would be discharged through the Petroleum Engineering Division (PED) Safety Directorate.

The system would operate as follows:-

1. The PED Safety Directorate would monitor the compliance of offshore installations with the requirements of the HSWA. The PED would themselves be responsible to the HSC.
2. Prior to the introduction of new regulations made under the MWA, the Secretary of State for Energy must consult the HSC.
3. Prior to the introduction of regulations made under the HSWA, the HSC must consult the PED to establish their suitability for offshore application.

This division of responsibility led to what many people believed was a dilution of the HSWA and that it created a conflict of interests within the Department of Energy. It was felt that the responsibility for occupational health, safety and welfare in any industry should not be held by the Department with policy making responsibility for that industry.

The situation was brought to a conclusion following the public inquiry into the Piper Alpha disaster of 1988.

### **1.3 CULLEN INQUIRY**

The explosion and resulting fires which engulfed the Piper Alpha installation on the 6 July 1988 claimed the lives of 167 offshore workers and led to the biggest shake up of the offshore safety regime for 20 years. The subsequent public inquiry chaired by the Hon. Lord Cullen proposed far reaching changes to the regulatory regime, and a comprehensive review of existing legislation with a view to its progressive replacement with a modernised and rationalised structure of Regulations.

As a result of the Inquiry the Offshore Safety Division (OSD) was created in 1990 as a department within the Health and Safety Executive (HSE). By the Spring of 1991, all duties pertaining to the occupational health, safety and welfare of offshore installations were transferred from the Petroleum Engineering Division (PED) of the Department of Energy, to the Offshore Safety Division of the Health and Safety Executive. The following year the first of the legislative reforms took place with the introduction of the Safety Case Regulations.

The reorganised PED and the new OSD would now fulfil the following functions.



## 1.4 DIVISION OF LEGISLATIVE RESPONSIBILITY - 1991

### i) HEALTH AND SAFETY EXECUTIVE, OFFSHORE SAFETY DIVISION (OSD).

The function of the various departments are in the main self explanatory and fall under the overall control of the Chief Executive.

#### OSD 1 POLICY AND LEGISLATION

- OSD 1A Safety Case liaison with Certifying Authorities
- OSD 1B General Policy, Workforce Involvement
- OSD 1C Management/Administration and Regulations
- OSD 1D Strategy, Policy Management, PFEER Regulations and Extractive Industry Directives
- OSD 1E Construction Regulations, Certification Review, and Extractive Industry Directives

#### OSD 2 RESOURCES AND SYSTEMS

- OSD 2A Information Systems and Staff Development
- OSD 2B Recruitment of Personnel and Administration
- OSD 2C Planning and Finance

#### OB OPERATIONS

- OB 1 Aberdeen/London – Inspections, Investigations, Safety Cases, Expert Teams, NRT's.
- OB 2 Aberdeen – Inspections, Investigations, Safety Cases, Expert Teams, NRT's.
- OB 3 Deputy Director – Inspections, Investigations, Safety Cases, Expert Teams, NRT's and Branch Planning.
- OB 4 Southern Operations – Inspections, Investigations, Safety Cases, Expert Teams, NRT's, Diving, pipelines and occupational health.

#### TU TECHNOLOGY

- TU 1 Structural Integrity, Naval Architecture
- TU 2 Topsides Facilities and Pipelines
- TU 3 Process Integrity and Analyses Unit
- TU 4 Hazard Analysis and Mitigation
- TU 5 Technical Strategy and Resource Management

### ii) PETROLEUM ENGINEERING DIVISION (PED)

The overall role of the PED is to ensure that exploration and development of the petroleum resources of the UK Continental Shelf (UKCS) achieve the maximum economic recovery of hydrocarbons.

- Branch 1. Exploration. Selection and issue of licensing blocks and the monitoring of all aspects of exploration.
- Branch 2. Development. Technical development of oil and gas fields and the monitoring of production figures and hydrocarbon reserves.
- Branch 3. Projects. Monitoring of development projects and provision of technical advice.

## **1.5 OFFSHORE INSTALLATIONS (SAFETY CASE) REGULATIONS 1992 (SI 1992/2885)**

The central recommendation of Lord Cullen's report on the Piper Alpha disaster was that every operator or owner of an offshore installation should prepare a safety case for each and every installation, both fixed and mobile, old and new. This decision was influenced by the Health and Safety Commission's (HSC) experience of regulating major hazards onshore under the Control of Industrial Major Accident Hazards Regulations 1984 (CIMAHS) (SI 1984/1902).

The new regulations cited as the Offshore Installations (Safety Case) Regulations are applicable to all new installations from the 30th November 1993 with older installations having until the 30th November 1995 to comply.

The new regulations are accompanied by a set of guidance notes to assist in the interpretation of the requirements and the preparation of the safety case, which is by its very nature a very involved and complex task. Safety cases are to be submitted to the HSE at the design stage, 6 months prior to admitting hydrocarbons onto the installation, and before the installation is eventually abandoned.

The primary aim of the safety case regulations is to reduce risks to the health and safety of the workforce employed on offshore installations.

Presented as a self contained document the safety case shares many similarities with the existing operations manual. Both are essentially designed to provide factual information such as the geographic, meteorological and oceanographic conditions which affect the installation, and include information and drawings showing the design and layout of the structure and plant. However, in addition to providing factual information the principal aims of the safety case are to ensure that:

- a) There is a safety management system (SMS) capable of ensuring compliance with statutory health and safety requirements.
- b) All hazards with the potential to cause major accidents have been identified, evaluated and measures taken to reduce risks to as low a level as is reasonably practicable.

The HSE place considerable emphasis on the importance of employing sound management practices to minimise the risks to personnel from working activities and the working environment. Consequently, a large part of the guidance notes are dedicated to an explanation of the extremely onerous requirements of this aspect of the regulations. The safety management system covers such topics as the requirement to provide written procedures for the systematic examination and operation of the installation and plant, and include details of the permit to work system. The safety management systems are to be monitored and audited on a regular basis to ensure their continued effectiveness.

The other departure from established offshore practices is the introduction of a requirement in the safety case to carry out a quantitative risk assessment (QRA) of the installation and its equipment. Where a QRA is not carried out the operator must offer an acceptable alternative form of engineering assessment.

Essentially quantitative risk assessment affords a means of identifying on paper in a systematic and thorough fashion, and in advance of plant start up, potential hazards to the installation, plant, process and personnel. It involves going through an installation drawing by drawing, system by system, and operation by operation. Often referred to as a hazop (hazard operational study), the analyses is designed to identify hazards which have the potential to cause a major accident. Examples of events classed as major accidents are the escape of hydrocarbons, impact with an aircraft or ship, structural failure and fire.

Having determined what the potential hazards are a hazan (hazard analysis) is carried out to assess the likelihood of their occurrence and the subsequent consequences. The results are compared with established standards and criteria and must show that the measures taken to prevent such occurrences are adequate.

The safety case is considered to be an essential ingredient to the safe operation of the installation and as such should be reviewed and updated at regular intervals to incorporate any changes which may have taken place in working practices, advances in technology, or modifications to the installation.

## **2. CERTIFICATION**

Basically Certification involves ensuring that all offshore installations located in UK territorial waters comply with the requirements of the Mineral Workings Act of 1971. They must possess a valid Certificate of Fitness in accordance with the requirements of Statutory Instrument No. 289.

### **2.1 THE OFFSHORE INSTALLATIONS (CONSTRUCTION AND SURVEY) REGULATIONS 1974, STATUTORY INSTRUMENT NO. 289**

To comply with the requirements of the Mineral Workings Act (MWA) the Secretary of State for Energy passed SI 289.

The SI 289 is a brief document which requires all offshore installations to have in effect a current Certificate of Fitness (C of F). Each and every item of equipment on the installation must comply with a recognised standard or specification, that is to be "fit for its intended purpose". The SI 289 is the single most important document relating to offshore installations and the expressions Certificate of Fitness and "fit for purpose" will be encountered repeatedly.

The Department of Energy publish guidance notes to assist in the interpretation of SI 289. The weighty volume is considered to be the offshore bible and is entitled Offshore Installations: Guidance on Design, Construction and Certification and is available from Her Majesty's Stationery Offices.

### **2.2 CERTIFYING AUTHORITIES**

This would be an opportune moment to introduce and explain the function of the certifying authorities (C/A).

The Mineral Workings Act, 1971 empowered the Secretary of State to ensure that offshore installations were certified and remained fit for purpose in compliance with the Regulations. The Secretary of State decreed that certifying authorities would be established who would fulfil the requirements of certification and issue the necessary Certificates of Fitness to offshore installations.

Whilst a Government department could carry out the functions required of a C/A, the Secretary of State decided to utilise existing ship classification societies to act on their behalf. The classification societies operate a similar certification scheme within the shipping industry and it was felt that the offshore industry would benefit from their established organisational framework and experienced personnel.

From 1974 to 1991 the Petroleum Engineering Division (PED) of the Department of Energy were responsible for monitoring the operational effectiveness of the Certifying Authorities. In 1991 these monitoring duties were transferred to the newly formed Offshore Safety Division (OSD) of the Health and Safety Executive (HSE).

The six classification societies approved to operate as certifying authorities and issue Certificates of Fitness on behalf of the Secretary of State for Energy, are:-

1. Lloyd's Register of Shipping - LRS
2. Bureau Veritas - BV
3. Det Norske Veritas - DNV
4. Offshore Certification Bureau - OCB
5. American Bureau of Shipping - ABS
6. Germanischer Lloyd - GL

### **2.3 CERTIFICATE OF FITNESS (C OF F)**

The point at which a C of F is required is oil/gas related and is issued at commencement of drilling. This normally coincides with the location of the drilling template or the jacket.

In order to issue a C of F the certifying authority must be in receipt of sufficient information to assess the design and construction methods of the proposed installation in order to confirm compliance with the requirements of SI 289.

Throughout the construction, installation and commissioning of the installation the C/A will carry out a monitoring function to ensure that the final product complies with the approved designs and current legislation. The cost of the C/A's involvement will be met by the owner of the installation.

The Certificate of Fitness remains valid for a period of five years subject to annual inspections being carried out by the certifying authority. At the end of the five years the C/A will carry out a major survey of the installation prior to renewal of the Certificate of Fitness.

### **LETTERS OF LIMITATION/QUALIFICATION**

Each Certificate of Fitness is accompanied by a Letter of Limitation and a Letter of Qualification. These letters enable the certifying authority to highlight deficiencies in operating procedures or equipment.

A limitation amounts to a restriction on the use of a particular item of equipment or operating procedure, e.g.:-

1. Pedestal crane not to be used until repairs have been carried out to the satisfaction of the certifying authority.
2. Cabin accommodation is to be restricted to two men per room.

A qualification tends to relate to items of a less critical nature than those dealt with by limitations and includes a date by which they must be dealt with, e.g.:-

1. Statutory Operations Manual to be updated within three months.
2. Planned maintenance records to be presented for examination within one month.

## **2.4 ANNUAL SURVEY**

To ensure that an installation is being maintained in accordance with the requirements of SI 289 the certifying authority must carry out annual mechanical, structural and electrical inspections.

The inspections will include a visual inspection of the installation and review of equipment certification and maintenance records. The attending surveyor will carry out whatever tests he considers necessary to ensure the installation and its equipment has been maintained correctly and may request the assistance of specialist inspectors to assess any areas of particular concern.

Should an operator require to modify or change any item of equipment on the installation during the course of the annual survey period, the approval of the certifying authority must first be obtained.

## **MAJOR SURVEY**

Prior to the issue of a new Certificate of Fitness, the certifying authority must carry out a major survey.

In addition to items examined during the annual survey, a major survey must include a more detailed investigation to ensure that no significant changes to approved designs have been made.

The major survey will include an underwater inspection of the structure of the installation. This is normally spread over the five year period as part of a planned maintenance programme carried out by a specialist diving contractor. This subject has been dealt with in a separate chapter.

The full scope of items which require examination by the certifying authority must be agreed with the owner of the installation at the beginning of each five year period.

## **3. ASSOCIATED INFORMATION**

### **3.1 HEALTH AND SAFETY EXECUTIVE (HSE) CORRESPONDENCE**

Official correspondence emanating from the Offshore Safety Division (OSD) of the Health and Safety Executive (HSE) may appear in any one of four guises, depending on the nature and urgency of the subject matter.

Distribution will be dependant on the content of the correspondence but will normally include the operators of offshore installations and the Certifying Authorities. Each item of correspondence is uniquely numbered and retains the format originally introduced by the Department of Energy.

The four levels of communication are:-

1. Continental Shelf Operations Notice. A CSON provides notification of a change to existing legislation, frequently an addition to, or modification of a Statutory Instrument. Adherence with the provisions of the notice are mandatory.

2. **Safety Alert.** A Safety Alert is normally issued in response to equipment failure the consequence of which could prove injurious to personnel. It is transmitted on an urgent basis, normally by fax or telex, to provide immediate notification of a potentially serious situation.
3. **Safety Notice (replaces Safety Letter).** The Safety Notice takes the form of a letter designed to highlight a potentially dangerous situation and recommends preventative action. The Notice should be retained on file by the installation and adopted as a guidance note.
4. **Diving Safety Memorandum (DSM).** A DSM represents the equivalent of a Safety Notice for the attention of personnel involved in diving operations.

### 3.2 STATUTORY INSTRUMENTS

Statutory Instruments are regulations passed by Parliament under the Mineral Workings Act of 1971 and apply to all fixed and mobile offshore installations maintained for the underwater exploitation of mineral resources in waters to which the 1971 Act applies.

The Statutory Instruments relating to offshore installations are:-

1. **Construction and Survey Regulations - Offshore Installations (Construction and Survey) Regulations 1974 (SI 1974 No. 289).**
2. **Operational Safety, Health and Welfare Regulations - Offshore Installations (Operational Safety, Health and Welfare) Regulations 1976 (SI 1976 No. 1019).**
3. **Emergency Procedures Regulations - Offshore Installations (Emergency Procedures) Regulations 1976 (SI 1976 No. 1542).**  
(to be withdrawn end of 1995)
4. **Life-saving Appliances Regulations - Offshore Installations (Life-Saving Appliances) Regulations 1977 (SI 1977 No. 486).**  
(to be withdrawn end of 1995)
5. **Fire-fighting Equipment Regulations - Offshore Installations (Fire-fighting Equipment) Regulations 1978 (SI 1978 No. 611).**  
(to be withdrawn end of 1995)
6. **Emergency Pipe-line Valve Regulations - Offshore Installations (Emergency Pipe-line Valve) Regulations 1989 (SI 1989 No. 1029).**
7. **Included Apparatus or Works Order - Offshore Installations (Included Apparatus or Works) Order 1989 (SI 1989 No. 978).**
8. **Inspectors and Casualties Regulations - Offshore Installations (Inspectors and Casualties) Regulations 1973 (SI 1973 No. 1842).**
9. **Public Inquiries Regulations - Offshore Installations (Public Inquiries) Regulations 1974 (SI 1974 No. 338).**

10. Well Control Regulations - Offshore Installations (Well Control) Regulations 1980 (SI 1980 No. 1759).
11. Safety Case Regulations - Offshore Installations (Safety Case) Regulations 1992 (SI 1992 No. 2885).

Statutory Instruments numbered 1 to 6 are discussed in detail elsewhere in the book. Those numbered 7 to 10 are brief in content and relate to legal requirements which would be of interest only to personnel at senior supervisory level. Number 11 marks the start of the more significant post Piper Alpha legislation and further reforms to existing statutory instruments will follow in due course, commencing with:

Prevention of Fire and Explosion, and Emergency Response - Offshore; Installations Regulations (date and number to be allocated when Regulations become law).

### 3.3 UK OFFSHORE OPERATORS ASSOCIATION (UKOOA)

UKOOA was officially established in 1973, having previously existed (from 1964) as an informal organisation. Every oil company engaged in exploration or production on the UK Continental Shelf (UKCS) is a member of UKOOA and it provides a forum for discussion on matters relating to technology, the environment and safety.

The Association operates purely in an advisory capacity and works closely with the Government to ensure that legislation obtains the desired results and reflects the requirements of the industry.

## **Chapter Three**

### **STATUTORY EQUIPMENT**

- PART 1. STATUTORY OPERATIONS MANUAL
- PART 2. FIRE FIGHTING EQUIPMENT
- PART 3. LIFE SAVING APPLIANCES  
AND EMERGENCY PROCEDURES
- PART 4. NAVIGATIONAL AIDS
- PART 5. MAINTENANCE AND REPAIR
- PART 6. HAZARDOUS AREAS





Offshore installations located within the territorial waters of the UK must comply with a number of Government laws which are presented in the form of Statutory Instruments (SI). They are based on principles of "good engineering practice" and on the SOLAS (Safety of Life at Sea) Convention, an agreement and publication formulated by IMO (International Maritime Organization).

The subjects covered in this chapter relate primarily to the requirements of the more significant Statutory Instruments and are only applicable to installations registered in the UK. However, some form of statutory regulations apply to virtually all offshore installations regardless of their nationality and geographic location and in most instances the arrangements found will be similar to those about to be discussed.

It should be noted that the regulations concerning fire fighting equipment, life saving appliances and emergency procedures are currently under review following the recommendations of Lord Cullen who chaired the public inquiry into the Piper Alpha disaster. To-date the Health and Safety Executive (HSE) have circulated a draft set of regulations within the industry with a request for general comments on the proposals. Sited as the Offshore Installations (prevention of fire and explosion, and emergency response) Regulations, they are due to become law in 1995, at which time a statute number will be allocated.

The proposed regulations are in the form of a single document which will eventually supersede the following Statutory Instruments;

- i. S.I. 1978/611 Fire-Fighting Equipment Regulations.
- ii. S.I. 1976/1542 Emergency Procedures Regulations.
- iii. S.I. 1977/486 Life Saving Appliance Regulations.

The new regulations impose a general duty on the operator (the duty holder) to make suitable and efficient arrangements for the purpose of:

- a) Protecting persons on the installation from fire and explosion; and
- b) Securing effective emergency response.

The regulations are accompanied by an Approved Code of Practice (ACoP) designed to clarify the intentions of the regulations and provide practical guidance on how safety goals may be achieved. The provisions of the ACoP are non-mandatory and as such provide an ideal means of incorporating future changes in working practices and technology without the need to resort to further legislation.

All new legislation will be retrospectively applied to existing installations "as far as is reasonably practicable".

## **Part 1 STATUTORY OPERATIONS MANUAL**

### **INTRODUCTION**

The regulations require that every offshore installation be provided with a Statutory Operations Manual. This is the rather grand name given to the book which contains a brief account of all the information necessary to enable the Offshore Installation Manager (OIM) to operate and maintain the installation in a safe condition.

The manual must be concise but it need not go into unnecessary detail provided that it directs the reader to more specific supporting documents. As an example, the Operations Manual must include a brief account of the operation and testing requirements of the emergency shutdown system (ESD) whilst a more detailed account of the system may be contained in the Emergency Procedures Manual.

A list of items that should be covered by the Statutory Operations Manual can be found in the Department of Energy Guidance Notes on the Design, Construction and Certification of Offshore Installations. The Certifying Authority must approve the contents of the manual prior to it being issued for use offshore and no subsequent modifications should be made to the manual without first obtaining their approval.

The Statutory Operations Manual should contain chapters which cover the following topics:-

#### **1. GENERAL INFORMATION**

Owners name, address and the geographic location of the installation.  
Date of installation of jacket and topsides.

#### **2. EXHIBITED DOCUMENTS**

Formal certification certificates such as:

- i) Certificate of Registration.
- ii) Certificate of Fitness (with associated Letters of Qualification and Limitations).
- iii) Emergency Procedure Notice (Station Bill).
- iv) Life Saving Appliance Plan.
- v) Fire Fighting Appliance Plan.
- vi) List of Operational Staff and their Duties.

#### **3. ENVIRONMENTAL CRITERIA**

Details of sea bed, foundations and piling.  
Maximum permissible loads for snow, ice and marine growth.  
Air gap measurement.  
Scour limitations.  
Differential settlement limits.

#### **4. CONSTRUCTION AND MATERIALS**

This section should include details of how corrosion and deterioration of the topside structures will be controlled. Information relating to the cathodic protection system and the protective paint coatings should be included.

## STATION BILL

COMOILCO 54/23 J

### GENERAL ALARM

THE SOUNDING OF A CONTINUOUS ALARM, ACCOMPANIED IN AREAS OF HIGH PLANT NOISE BY FLASHING LIGHTS, INDICATES AN EMERGENCY.

### DO NOT PANIC

- \* ALL PERSONNEL WILL PROCEED TO THE NEAREST MUSTER POINT AND DON A LIFE JACKET.
- \* A HEAD COUNT WILL BE TAKEN.
- \* FURTHER INSTRUCTIONS WILL BE GIVEN BY THE OIM, OR A PERSON NOMINATED BY THE OIM.

### MUSTER POINTS

ACCOMMODATION PLATFORM (JA) - CHANGING ROOMS  
PRODUCTION PLATFORM (JP) - CONTROL ROOM

### LIFEBOATS

LOCATION - JA PLATFORM - WEST SIDE  
- JP PLATFORM - EAST SIDE

DO NOT ENTER LIFEBOATS UNTIL INSTRUCTED TO DO SO.

### SURVIVAL EQUIPMENT

LIFE JACKETS, IMMERSION SUITS AND SMOKE HOODS ARE LOCATED:

- IN CABINS
- AT MUSTER POINTS
- IN BOXES AS SHOWN ON LSA PLAN

### FIRE

RAISE ALARM BY:

- AND
- (i) ACTIVATING BREAK GLASS UNIT
  - (ii) ANNOUNCING "FIRE" REPEATEDLY OVER THE PUBLIC ADDRESS SYSTEM

TRY TO EXTINGUISH A SMALL FIRE IMMEDIATELY AFTER RAISING THE ALARM.

### MAN OVERBOARD

- 1 THROW NEAREST LIFE RING TO MAN
- 2 KEEP MAN IN SIGHT AT ALL TIMES
- 3 RAISE ALARM USING PUBLIC ADDRESS SYSTEM
- 4 CONFIRM STAND-BY BOAT ALERTED

### EMERGENCY SERVICES HELP

BACTON CONTROL: TELEPHONE 4777 or 4999 or V.H.F. CHANNEL 1  
COMOILCO BASE: TELEPHONE 4545 or V.H.F. CHANNEL 1  
STANDBY-BOAT: V.H.F. CHANNEL 8

STATION BILL

**5. STRUCTURE - LAYOUT AND NOTATION**

General arrangement drawing of the deck structure showing details of the accommodation, helideck and topside facilities. General arrangement of the jacket showing piling details and the location of risers conductors and caissons.

**6. EQUIPMENT - LAYOUT AND NOTATION**

General arrangement drawing showing details of the process facilities and the main items of plant and machinery.

**7. HAZARDOUS AREAS**

Hazardous area and dangerous substance drawings. Philosophy and specifications used to formulate the drawings.

**8. PROCESS SYSTEMS**

Line diagrams showing the basic layout of the hydrocarbon processing equipment, e.g., oil, gas, condensate, drain and vent systems.

**9. UTILITY SYSTEMS**

Line diagrams showing the basic operation of the utility systems, e.g., compressed air, potable water, service water, etc.

**10. PRESSURE VESSELS, TANKS AND RELIEF VALVES**

List of vessels specifying unique numbers, serial numbers, design conditions, safe working pressures and inspection requirements.

**11. PIPING**

Design specifications.  
Colour code system.

**12. CRANES AND LIFTING EQUIPMENT**

Summary of equipment specifications which should include the safe working load radius charts for pedestal cranes.

**13. MAINTENANCE**

Reference standards covering the planned maintenance of all items of electrical and mechanical equipment and associated protection devices.

**14. UNDERWATER STRUCTURE**

Detailed drawings of the jackets and description of the underwater planned maintenance programme.

**15. HELICOPTER/VESSEL OPERATIONS**

Standard procedures for communication with helicopters and supply/standby boats.

**16. COMMUNICATIONS**

Detail of methods of communication from rig to supply boats and to the beach, e.g. VHF, microwave.

**17. EMERGENCY SHUTDOWN SYSTEM (ESD)**

Line diagram identifying the main components of the ESD system and their operational status.  
ESD logic matrix.  
Design philosophy on which the ESD system operates.

**18. WELL CONTROL EQUIPMENT**

Details of mudline safety valves, christmas tree, fire loop and wellhead control panel.

**19. ESCAPE ROUTES AND LIFE SAVING APPLIANCES**

Plan of the installation showing the location of all items of life saving equipment in accordance with the requirement of SI 1977/486.  
Details of the public address system, general alarm and muster/evacuation procedures.

**20. FIRE AND GAS DETECTION**

Account of the philosophy on which the fire and gas system operates.  
Cause and effect chart showing the various stages of activation and the levels of response obtained.

**21. FIRE PROTECTION**

Extent of the passive fire protection measures.  
Plan of the firefighting equipment in compliance with the requirements of SI 1977/611.

**CONCLUSION**

The information provided in the Statutory Operations Manual should enable a visitor to the installation to quickly familiarise himself with the installation layout and design conditions.

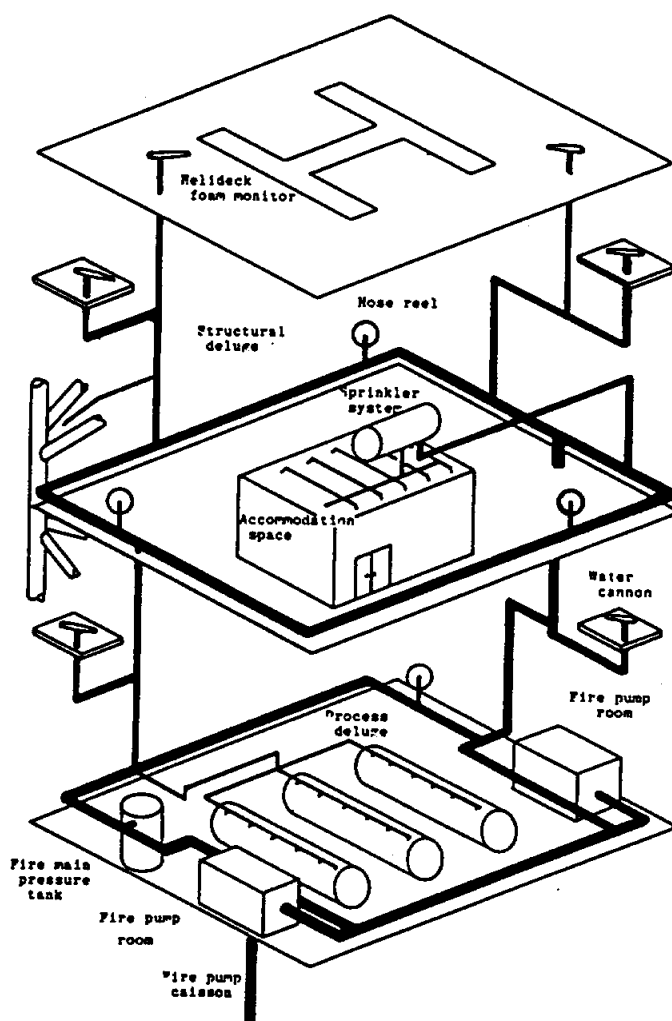
## Part 2 FIRE FIGHTING EQUIPMENT

### INTRODUCTION

Offshore Installations must provide protection against the hazards of fire and the release of gas by employing a combination of active and passive fire fighting/protection measures.

Statutory Instrument No. 1978/611 Offshore Installations (Fire Fighting Equipment) specifies the requirements for active fire fighting equipment and the Department of Energy publish Guidance Notes to assist in the interpretation of the regulations. The requirements for passive fire protection measures can be found in the Department of Energy: Offshore Installations, Guidance Notes on the Design, Construction and Certification.

It should be noted that SI 611 is currently under review and due to be replaced in 1995 with the Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations. The intention of the new Regulations is to provide a less prescriptive form of legislation which will encourage a more integrated approach to the hazards associated with fires and explosions.



FIRE MAIN

It is unlikely that the new regulations will require any significant changes to the type of equipment installed under SI 611. However, rather than dictating exactly what equipment must be provided and what precautions must be taken, as is the case with existing regulations, the proposed regulations require that a fire and explosion analysis (FEA) be carried out. The object of the fire and explosion analysis is to identify events which could give rise to a major incident resulting in a fire or explosion and evaluate the likelihood and consequences of such an incident occurring. It is the results of the analysis which will ultimately dictate what precautions should be taken to prevent such an occurrence arising and should one occur, recommend steps which will detect, control and mitigate the effects.

A summary of the main features of the fire and explosion analysis is to be included in the Safety Case and it should be updated at regular intervals to incorporate changes which may have taken place in working practises, advances in technology, or modifications to the installation.

## **1. ACTIVE FIRE PROTECTION**

The regulations require the provision of fire and gas detection systems, remote control safety devices, fire extinguishers and fireman's equipment on all installations (manned or un-manned) and fire alarms, fire mains, hydrants and hoses, water deluge systems or monitors, and automatic sprinkler systems on all installations that are normally manned.

Each and every piece of fire fighting equipment must be of a type approved by the Department of Transport (DOT), Marine Division, or an equivalent national standards organisation and must be located in accordance with an approved fire fighting equipment plan. This plan must be clearly displayed in the main accommodation and at an appropriate working space such as the main control room.

Every two years offshore installations are subjected to an examination of the fire fighting equipment to establish continued compliance with the regulations. On satisfactory completion of the survey a Record of Survey form is issued which should be displayed onboard the installation. Up until 1992 these inspections were carried out by the Department of Transport's marine surveyors, a duty since transferred to the Certifying Authorities under the auspices of the Health and Safety Executive (HSE). The survey may be combined with the biannual examination of life saving appliances.

The SI 611 lays down the minimum requirements for fire fighting equipment but considerable scope exists as to the type of equipment which may be installed and the philosophy under which it operates. The arrangements provided by one oil company may differ considerably from those of another whilst still complying with the Regulations. The fire and gas philosophy must ultimately be approved by the Certifying Authority.

All the major items of fire fighting equipment must be manufactured, installed and tested under the supervision of a Certifying Authority.

A brief description of the various component parts of an active fire protection system as applicable to a normally manned offshore installation will now be given.

### **1.1 FIRE DETECTION**

Automatic fire detection systems must be fitted throughout the installation and the equipment used must be of a self monitoring design so that if a fault develops a warning alarm will be activated.



## STATUTORY EQUIPMENT

Manually activated alarm points must be provided at strategic positions in the accommodation and in working areas.

Detectors sensitive to smoke, heat, ultraviolet light and gas may be used individually or in combination depending on the hazard most likely to occur in any particular location.

The main control room is usually dedicated for use as the fire control station because the operation of production equipment and communications can most easily be co-ordinated at that point. The main control room is also normally manned 24 hours per day, at least on the larger installations (where the control room is not normally manned a repeater alarm must sound in a manned location or cabin).

It is a requirement that should a detector sense a hazard or a manual alarm point be activated, then an audible and visual alarm will be initiated at the hazard and in the main control room. There is no requirement for the alarm to sound throughout the installation or for the automatic operation of the fire fighting equipment. The location of the hazard must be identified in the main control station and the operations staff can then decide what action is to be taken.

### 1.2 FIRE FIGHTING EQUIPMENT

The active fire fighting system centres around a ring main and two fire pumps as shown in the sketch. The system is normally maintained at a constant pressure of approximately 10 bars (150 psig) by a sea water service pump and pressure tank. Operation of an item of fire fighting equipment will cause a significant drop in ring main pressure that will activate a fire pump. Alternatively a fire pump can be manually started from strategic locations such as the main control room, helideck and process areas.

The fire pumps consist of a centrifugal deepwell pump that is normally powered by a self contained diesel engine although electric drives are occasionally used.

The more formal regulations which apply to fixed fire fighting systems may be summarised as follows:-

#### i) FIRE PUMPS

Normally, at least two independently powered fire pumps are required on each offshore installation. They must be located remotely from each other in areas of minimal risk and be capable of operating for a 12 hour period unattended. Each pump should be capable of supplying adequate water to operate the largest section of deluge equipment and still maintain an adequate fire main pressure.

#### ii) FIRE MAINS

The fire main should be constructed of corrosion resistant materials and protected against freezing. Suitable isolation valves should be installed so that a damaged section of fire main will not adversely affect the operation of the remaining system.

#### iii) HOSE REELS

A number of hose reel stations must be provided so that water can be brought to bear on a fire from at least two directions using no more than two sections of hose joined together.

**iv) DELUGE**

The deluge system is required to protect any equipment used to process hydrocarbons. It covers the wellheads and gas process plant in its entirety and it may be manual or automatic in operation.

The deluge system is similar in design to a sprinkler system with the exception that frangible bulbs are not fitted, the pipework remaining 'dry' until the deluge valves are opened. The water supply is intended to cool the plant and reduce the escalation of a fire. The deluge system is frequently extended to cover the main structural steelwork to prevent it from weakening if exposed to fire.

**v) WATER MONITORS**

A monitor may be described as a permanently fixed device for directing water or foam in jet or spray form onto a fire, in effect a water cannon.

In theory it is acceptable to use water monitors in place of a deluge system to protect process areas but in practice the monitors are normally fitted in addition to the deluge systems.

Water monitors are also used to protect the helideck on normally manned installations. They must be capable of discharging a sufficient quantity of dense fire fighting foam to completely cover the helideck, even in adverse weather conditions. A tool kit containing equipment to assist in releasing the occupants from helicopter wreckage will also be found in the immediate vicinity of the water monitors.

**vi) SPRINKLER SYSTEM**

Every accommodation space must be protected by an automatic sprinkler system. It must be supplied with a water source remote from the accommodation which is capable of operating for a period of at least 4 hours.

Operation of the sprinkler system must activate an audible and visual alarm and indicate the location of the hazard at the main control station.

The sprinkler frangible bulbs will operate at approximately 70 deg. C (158 deg. F) in most accommodation spaces with the exception of the galley where higher settings may be used.

**1.3 FIXED FIRE FIGHTING SYSTEMS**

It is a requirement that certain locations such as control rooms and machinery spaces are protected by fixed fire extinguishing systems.

The favoured medium for the extinguishant is halon although carbon dioxide and dry powder systems are also used. Initiation of the fixed fire fighting equipment may be automatic but manual operation is often preferred for normally manned locations.

The various mediums may briefly be described as follows:

**i) HALON**

This is a lighter than air gas which relies on a chemical reaction to break the combustion chain and extinguish the fire. It is virtually instantaneous in operation, leaves no mess and is easily dispersed once the area has been made safe.

## STATUTORY EQUIPMENT

Air to be supplied from a safe area.  
Gas detection is desirable but not mandatory  
(gas not expected in a safe area).

### DOORS

Zone 1 to/from a safe area - Air lock  
to be fitted with gas tight doors.  
Zone 1 to/from a Zone 2 - Single  
gas tight door satisfactory.  
Zone 2 to/from a safe area - Single  
gas tight door satisfactory.

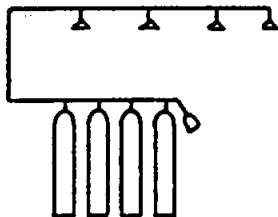
Pressurization: Required in all cases (5 mm water).  
Action on loss of pressurisation:-

- i. Uncertified electrical equipment  
Zone 2, Initiate LOP alarm  
Zone 1, Initiate LOP alarm  
and isolate all electrical equipment  
not rated for Zone 1 service.
- ii. Certified electrical equipment  
Zone 2, No alarm or isolation  
of electrical equipment required.  
Zone 1, Initiate LOP alarm and take immediate  
action to restore integrity of system.

The Loss of Pressurisation alarm must be  
audible locally and when the compartment is  
not normally manned the alarm should  
have a repeat facility at a normally manned  
location.

**FIRE DETECTION** - Every accommodation space to be protected with an  
automatic sprinkler system.

Every working space not protected by a sprinkler system shall have an  
automatic fire detection system.



**FIXED FIRE FIGHTING SYSTEMS** - All machinery spaces  
and control rooms to be fitted with a fixed fire  
fighting system which may be activated automatically  
or manually.

Activation of an automatic fire extinguishing system  
must activate an alarm locally and at the main  
control station.



Where a fuel supply is contained with a machinery  
space a remote fuel isolation valve must be fitted.

**VENTILATION** - Air to be expelled to a safe area.  
However, air can be expelled to a Zone 1 or  
Zone 2 area if automatic gas tight closing  
devices are fitted, and a spark arrestor where  
a compartment contains equipment that could  
generate sparks. All ventilators must be capable  
of operation locally and remotely.

## FIRE AND GAS PROTECTION REQUIREMENTS

Halon is normally used to protect control rooms, plant rooms, battery enclosures and any locations housing delicate equipment. It is also favoured for the protection of machinery spaces such as turbine enclosures and engine rooms where its operation is invariably automatic. Halon status lights must be fitted outside the protected space to indicate whether the system is in the auto, manual or discharged condition. Before the halon is released the ventilation systems must be shut down and visual and audible alarms activated in the affected area.

**ii) CARBON DIOXIDE (CO<sub>2</sub>)**

Carbon Dioxide was used almost universally prior to the introduction of halon. It is still used in locations where its heavier than air smothering effect is considered to be most suitable, such as in vent stack fires.

**iii) DRY POWDER**

Like halon, dry powder relies on a chemical reaction to break the combustion chain and whilst it is very effective it leaves a tremendous mess. Again it may be used to fight vent stack fires.

**1.4 PORTABLE FIRE FIGHTING EQUIPMENT**

A considerable number of portable fire fighting extinguishers are located throughout offshore installations. Extinguishers using water, foam, dry powder and CO<sub>2</sub> will be installed at vantage points as specified on the installation fire fighting plan.

Whilst the preceding text reflects current offshore practice, there are moves afoot to ban halon because of its damaging effect on the ozone layer and countries party to the Montreal Protocol have agreed that halon should be phased out by the year 2000. From July 1992 the use of halons on new installations has been restricted to those locations designated as "essential", i.e. normally manned spaces such as main control rooms.

Chemical manufactures have produced alternatives to halon but they are not at present commercially available and this has prompted a return to carbon dioxide as the primary extinguishant for fixed fire fighting systems. Whilst carbon dioxide is termed a green house gas it is produced as a bi-product of chemical manufacturing processes and would normally be vented into the atmosphere anyway.

**1.5 REMOTE STOPS AND CLOSING DEVICES**

In order to minimise the spread of fire and maximise the efficiency of the fixed fire fighting mediums the following mandatory requirements apply.

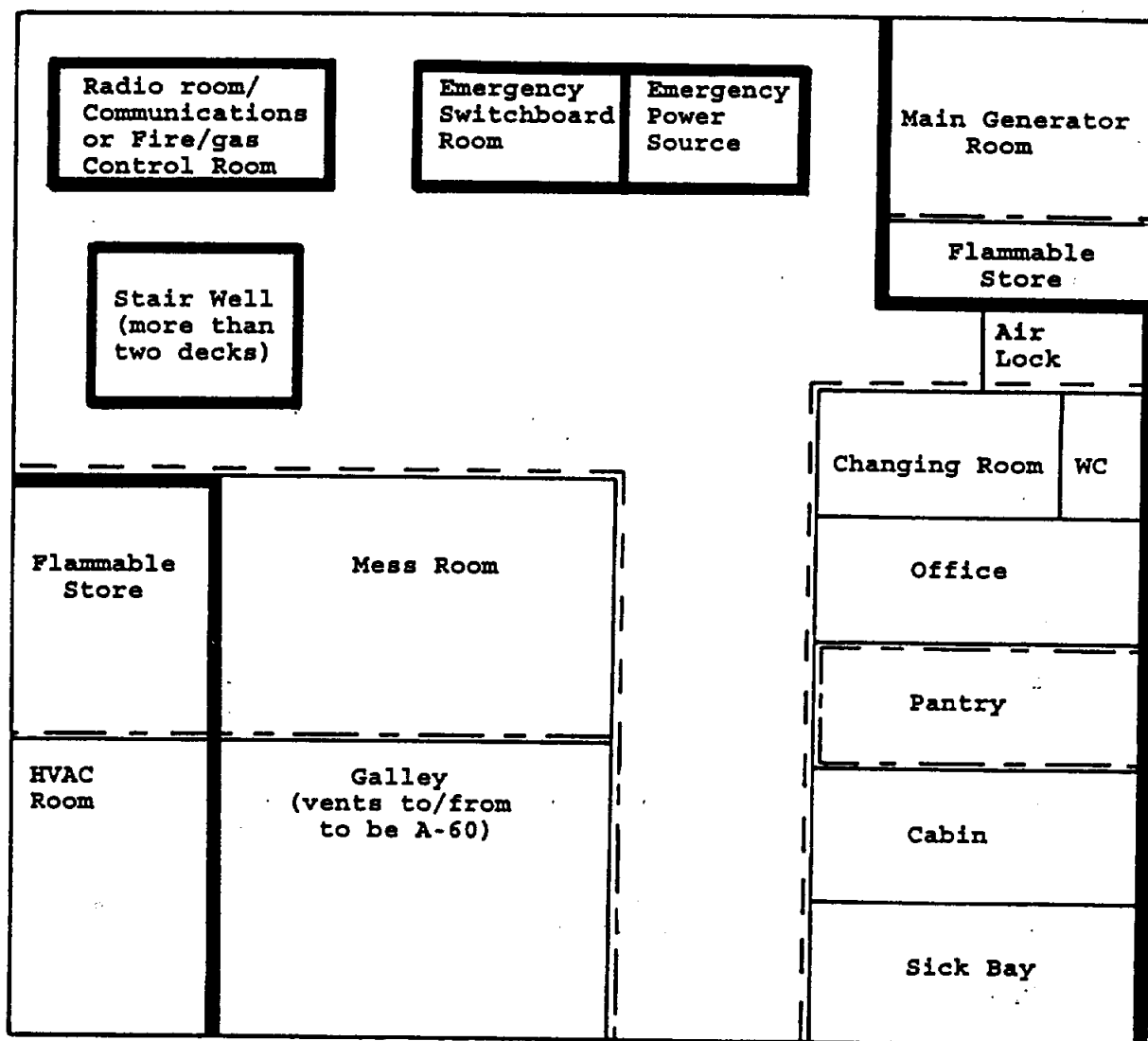
**i) VENTILATION SYSTEMS**

Remote stops for ventilation fans and remote closing devices for ventilator flaps are to be provided. Modern installations may employ a centralised ventilation control system which can be operated from the main control room. This facilitates the isolation of specific areas which can be returned to service as and when required to assist in the dispersion of smoke.

**ii) FUEL SYSTEMS**

Compartments containing gas or diesel powered machinery must be provided with fuel isolation valves located externally to the machinery space.

# STATUTORY EQUIPMENT



A - 60 Facing Process  
(H - 120 proposed)

- A-60
- - - -** B-15
- =====** Non combustible (60 mins.)

## PASSIVE FIRE PROTECTION

## **2. PASSIVE FIRE PROTECTION**

The requirements for passive fire protection are outlined in the Department of Energy Guidance Notes on the Design, Construction and Certification of Offshore Installations.

Passive fire protection involves the use of non-combustible heat resisting materials to insulate strategic locations against the effects of fire and smoke. The materials used are generally mineral wools, fibre partitioning boards and cementitious coatings and all must be certified as having had their effectiveness proved by type testing within a controlled furnace atmosphere. The manufacturers of these materials provide literature to show how their products must be installed to achieve the desired protection.

Various designations are used to specify the structural fire protection requirements and A, B and H class divisions will be terms frequently encountered. A time interval is normally included within the fire rating so that if for example an A-60 barrier is specified then this will maintain the integrity required of an A class division for a period of 60 minutes.

The most commonly used divisions may be briefly described as follows:

### **i) A CLASS DIVISIONS**

These must be capable of withstanding a standard fire test and preventing the passage of smoke and flame for the specified period.

The standard fire test involves heating one side of the insulating material and its support structure to a furnace temperature which will exceed 925°C.

As previously stated, an A-60 barrier must remain intact for a period of 60 minutes and this most arduous of specifications must be used to protect the main control room, emergency sources of power and communications, and all accommodation boundaries that face a hazardous area on offshore installations.

Typical A-60 arrangements are shown in the sketches, a steel bulkhead providing structural integrity whilst a dense mineral wool provides the thermal insulation.

### **ii) B CLASS DIVISIONS**

These are exposed to a standard fire test in a similar manner to 'A' class divisions. They must be capable of preventing the passage of flame (but not smoke) to completion of the fire test but the duration is typically only 15 minutes.

The B-15 fire rated fibre board partitioning panels are used extensively in the construction of bulkheads, ceilings and corridors in the vicinity of non-critical areas such as accommodation rooms located in safe areas.

### **iii) H CLASS DIVISIONS**

These are constructed in a similar manner to A class divisions but additional or improved ceramic fibre based insulations must be applied to withstand the more rigorous demands of a hydrocarbon fire test. The final furnace temperature is at least 1100°C and the tests are frequently carried out for 120 minutes to give an H-120 rated division.

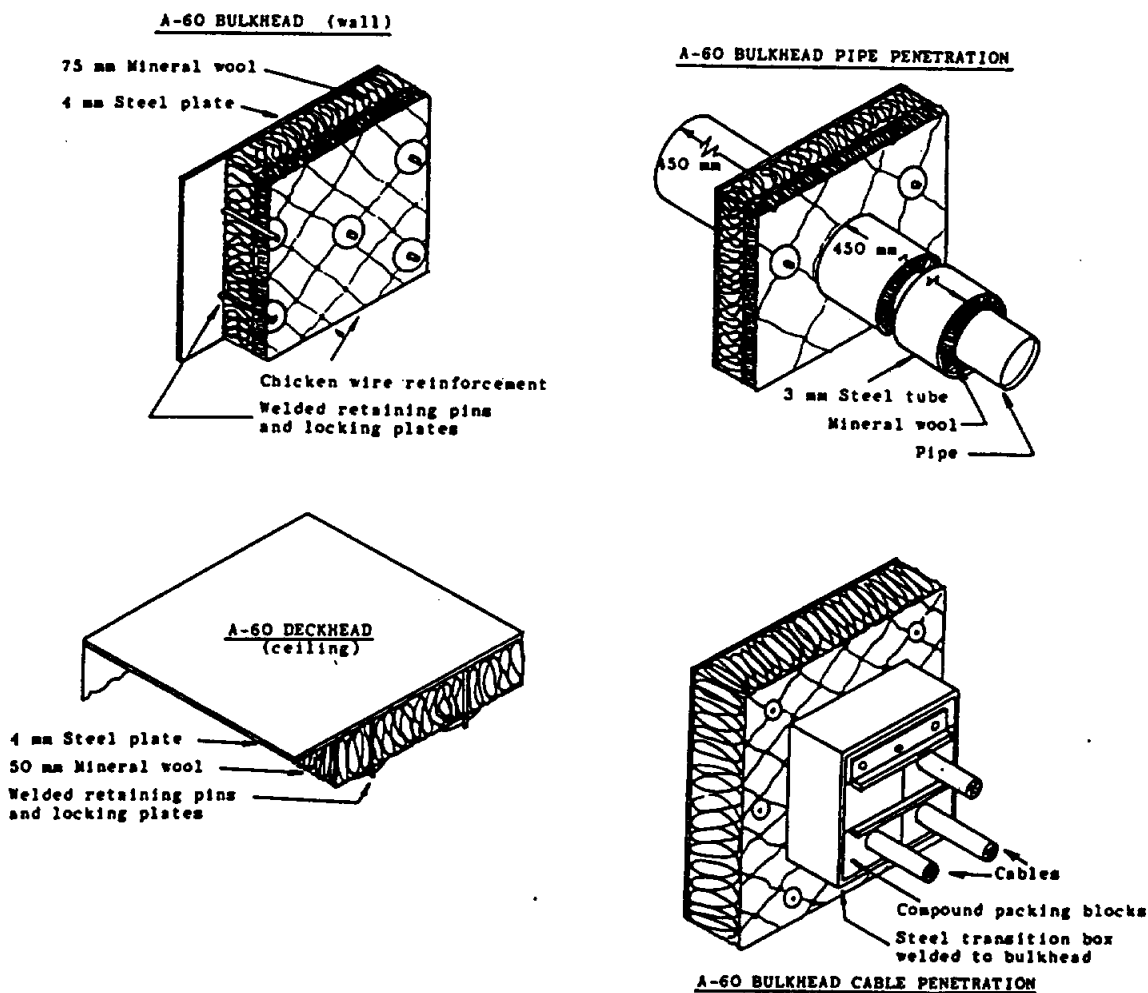
## STATUTORY EQUIPMENT

The H-120 specification is a relatively new requirement and is recommended for use on accommodation boundaries that face locations where a hydrocarbon fire could occur such as wellheads and process areas. It is also specified for the protection of subsea riser pipes in the vicinity of the emergency shutdown valve (ESDV).

On completion of a fire test, be it for an A, B or H rated division the surface remote from the fire should not register an increase in average temperature of more than 139°C.

All items which penetrate fire rated divisions are to be certified to the same standards as the division itself. That is to say all doors, windows, ventilation ducts, pipe and cable transits must be approved as H-120, A-60 or B-15 or to whatever fire rating the design drawings specify.

In addition to structural fire protection requirements it is recommended that all furnishings and internal decor be constructed to comply with the requirements of the various parts of BS 476 which defines standards for the resistance, incombustibility and non-inflammability of building materials and structures.



## TYPICAL PASSIVE FIRE PROTECTION ARRANGEMENTS

## **Part 3. LIFE SAVING APPLIANCES**

**INTRODUCTION** - All offshore installations must comply with the regulations specified in Statutory Instrument No. 486 - Life Saving Appliances. The Department of Energy publish Guidance Notes on Life Saving Appliances to assist in the interpretation of the regulations.

It should be noted that SI 486, and SI 1542 (Emergency Procedures) are currently under review and due to be replaced in 1995 with the Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations. The intention of the new regulations is to provide a less prescriptive form of legislation which will encourage a more integrated approach to the selection of life saving appliances and the formulation of emergency procedures.

With the exception of additional items of personal survival equipment, the new Regulations are unlikely to require any significant changes to the type of equipment installed and measures taken under the existing Statutory Instruments. However, rather than dictating exactly what equipment must be made available and what precautions should be taken, as is the case with existing regulations, the proposed regulations require that an evacuation, escape and rescue analysis (EERA) be carried out.

The object of the analysis is to identify hazardous events which could result in a major accident occurring, evaluate the likelihood and consequences of such an event occurring, and recommend suitable arrangements for the evacuation, escape and rescue of personnel. All types of emergency are to be taken into consideration ranging from major incidents involving fire and explosion to persons overboard.

A summary of the main features of the EERA is to be included in the Safety Case and it must be updated at regular intervals in order to incorporate changes which may take place in working practices, advances in technology, or modifications to the installation.

The following text gives a brief account of the main items of life saving appliances required to comply with SI 486, and the forthcoming regulations.

Each and every piece of life saving apparatus must be of a type approved by the Department of Transport (DoT), Marine Division, or an equivalent national standards organisation and must be located in accordance with an approved life saving appliance plan. This plan must be clearly displayed in the main accommodation and at an appropriate working space such as the main control room.

Every two years offshore installations are subjected to an examination of the life saving appliances to establish continued compliance with the regulations. On satisfactory completion of the survey a Record of Survey form is issued which should be displayed on board the installation. Up until 1992 these inspections were carried out by the Department of Transport's marine surveyors, a duty since transferred to the Certifying Authorities under the auspices of the Health and Safety Executive (HSE). The survey may be combined with the biannual examination of firefighting equipment.

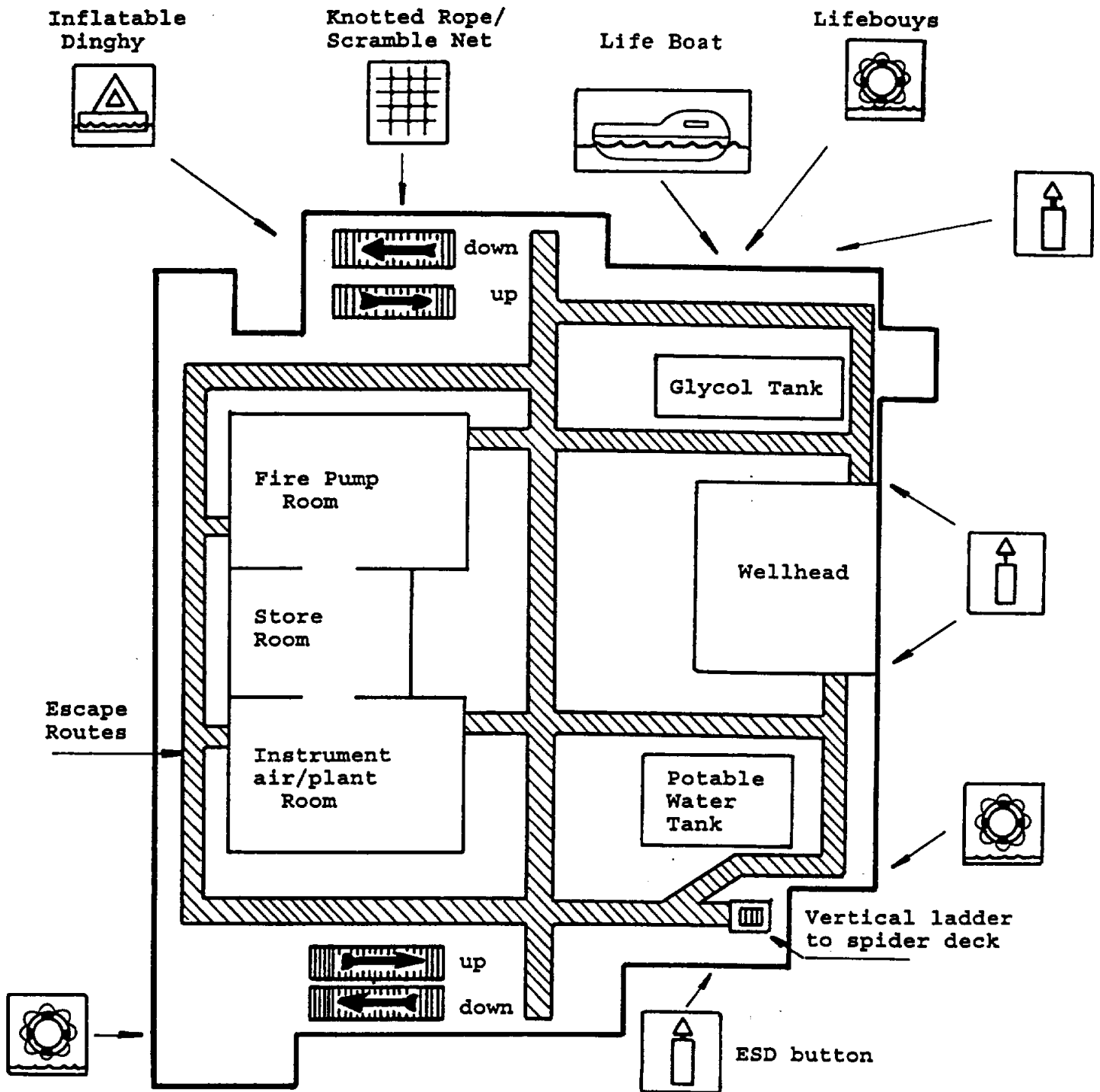
### **1. ALARM AND PUBLIC ADDRESS SYSTEM**

- i) A general alarm must be provided which is clearly audible at all locations on the installation.
- ii) A public address system which permits aural communication (a talk back facility) must be provided at all parts of the installation.



# STATUTORY EQUIPMENT

## PLAN ON CELLAR DECK



LIFE SAVING APPLIANCE (LSA) PLAN

Where the alarm and public address systems are located in noisy surroundings a visual form of indication is to be provided. Both systems must be supplied with two separate sources of electrical power, one of which is designed to function in an emergency situation.

## **2. TEMPORARY REFUGE AND MEANS OF ESCAPE**

A temporary refuge or safe haven is to be provided where personnel can congregate should an emergency situation develop involving fire and explosion, or a release of gas. Clear lines of access should be provided for personnel entering the refuge and for egress to the evacuation stations. Life support systems are to be provided which will protect the occupants for a period of time determined from the results of the fire and explosion (FEA) and evacuation, escape and rescue (EERA) analyses. The temporary refuge must provide means to monitor the emergency situation and facilities for communication with the emergency services.

There must be suitable means provided for personnel to reach the helideck and the sea by at least two routes. Escape to the sea may be effected using fixed ladders, knotted ropes or scramble nets.

All escape routes are to be clearly signposted, kept clear of obstructions and provided with adequate emergency lighting arrangements.

## **3. SURVIVAL CRAFT**

### **i) LIFE BOATS**

Every normally manned installation must be provided with a totally enclosed motor propelled survival craft (TEMPSC) capable of containing all persons on board (POB).

Clear instructions are to be provided which will enable one person to launch and operate the life boat.

The life boat must be self righting, constructed of fire retardant materials and protected against heat by an external sprinkler system. There must be sufficient fuel on board to propel the boat for 12 hours and a compressed air supply which will enable the occupants to breath, and the engine to run for at least ten minutes. A radio which can transmit distress signals must also be included in the survival equipment.

### **ii) LIFE RAFTS**

The requirements for life raft depend on the capacity of the life boats. If one life boat can accommodate the entire POB then additional capacity equal to the POB must be provided by life rafts. That is to say the combined capacity of life boats and life rafts equals 2 x POB.

The alternative is to provide two life boats whose combined capacity equals 1.5 x POB in which case no life rafts need be fitted. In practice inflatable life rafts are positioned at strategic locations regardless of life boat capacity. These inflatable life rafts should be serviced annually.

All survival craft must contain a first aid kit, an adequate supply of drinking water and a waterproof electric hand lamp suitable for signalling purposes.

#### 4. LIFE JACKETS

The HSE have advised that forthcoming legislation will include a requirement that each individual should be provided with an immersion suit, a smoke hood, torch and fireproof gloves in addition to a lifejacket.

There must be located on each installation a quantity of life jackets equal to 1.5 x the POB. One must be stored by each bed with the remainder being located at embarkation or muster points. Donning instructions must be provided wherever the jackets are stored. Each jacket should be capable of keeping a person afloat for a period of 24 hours and be fitted with a whistle and preferably a light.

#### 5. LIFE BUOYS

The number of life buoys required will depend on the number of POBs but at least eight must be sited at locations readily available to assist a person who has fallen into the sea. The life buoy must be fitted with a light which will operate for at least 45 minutes.

Life boats and life buoys must all bear the name of the installation.

### EMERGENCY PROCEDURES SI NO. 1542

In addition to complying with the requirements of SI 486, offshore installations must comply with SI 1542, Offshore Installations (Emergency Procedures) Regulations 1976, which require the provision of an emergency procedures manual.

As previously stated, SI 1542 is currently under review and will eventually be withdrawn. The proposed new regulations cover similar ground to the existing SI's but are less prescriptive in nature. Future emergency procedures will be based on recommendations highlighted in the evacuation, escape and rescue analysis (EERA).

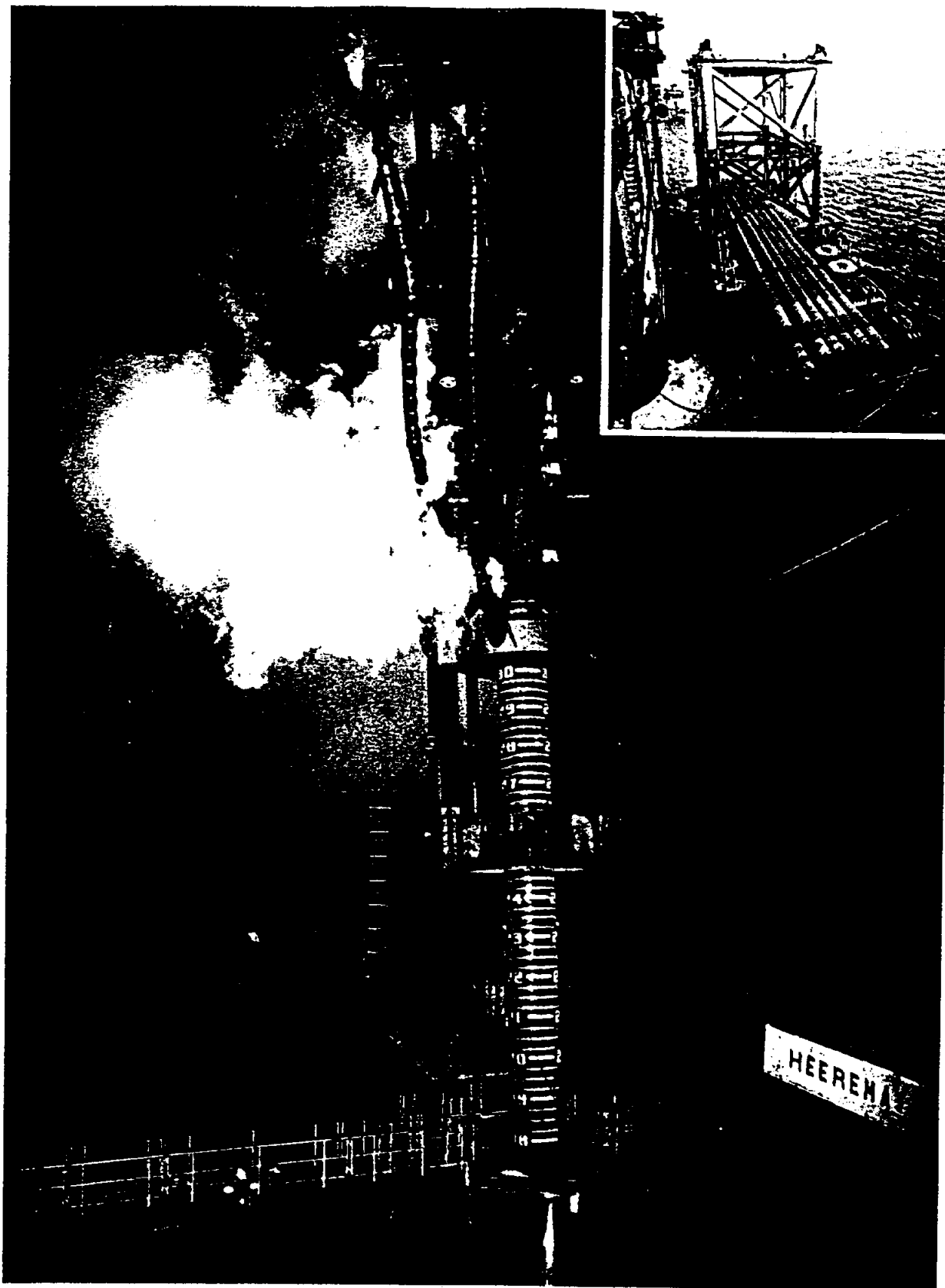
The SI 1542 clearly specifies the items which should be covered by the emergency procedures manual but the main requirement is that written procedures be provided which deal specifically with the action to be taken should the following emergencies occur:-

1. Fire or explosion.
2. Well blow-out.
3. Leakage of oil or gas.
4. Helicopter accident.
5. Man overboard.
6. Death, serious injury or illness.

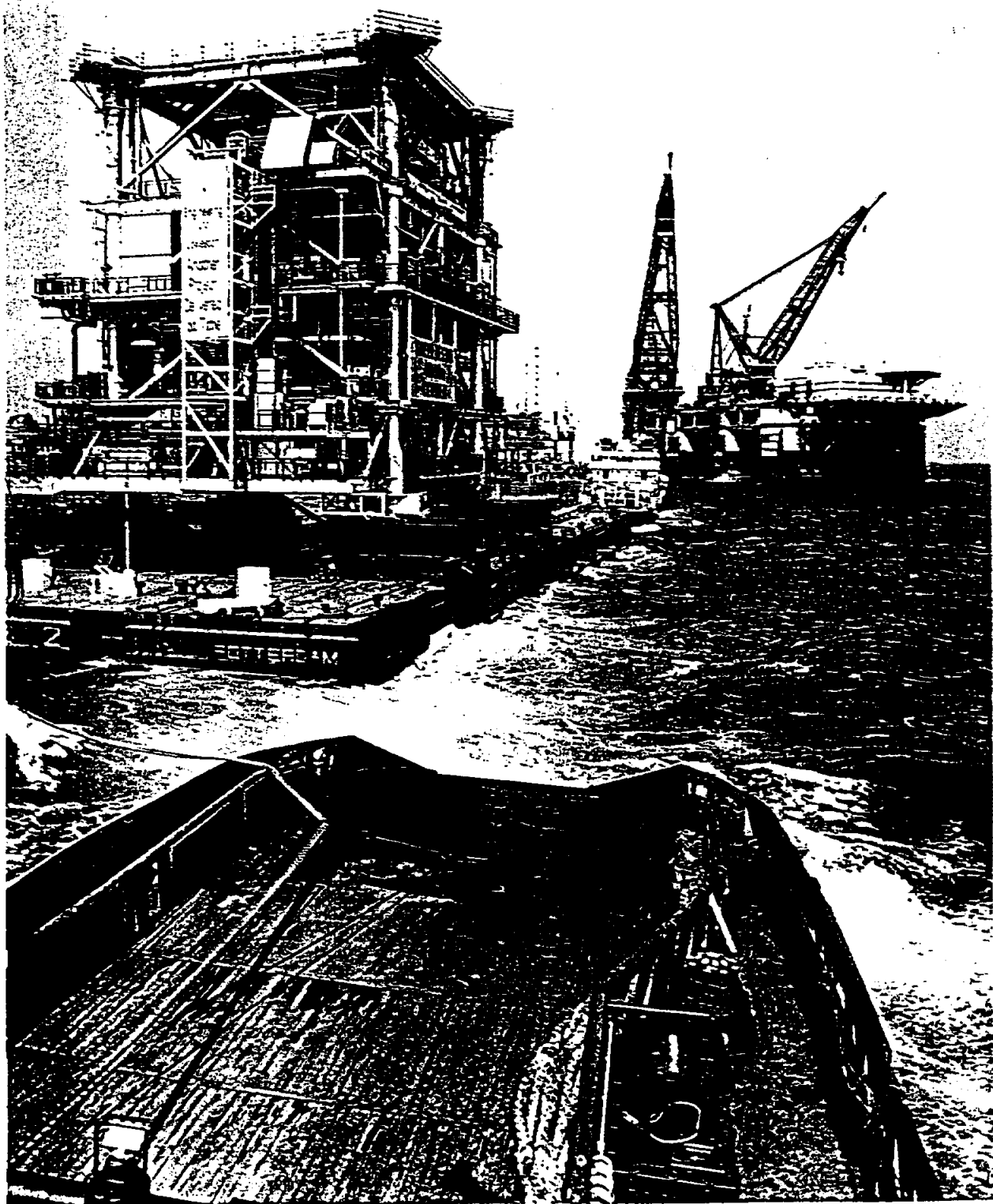
### *Offshore Engineering*

SI 1542 further requires that regular musters and safety drills be carried out and that these be recorded in the official logbook. A list of names of the individuals nominated to carry out emergency duties such as the organisation of firefighting teams and the making safe of wells must be displayed at muster points.

One further point worth mentioning is that SI 1542 requires the permanent attendance of a standby vessel (within 5 nautical miles) which can accommodate the entire complement of the installation and provide first aid should the rig need to be abandoned.



9 - The offshore industry works around the clock, 365 days a year. This night time shot shows the steam hammer of the Heerema Balder in action driving the foundation piles through the legs of the Shell/Esso 49/26 Foxtrot jacket. Inset - one of the Shell/Esso 48/19a Clipper jackets and foundation piles during transportation. Note the comparative size of the men on the barge, the unpainted lower steel structure and the depth graduations on the piles.



10 - The transportation to site of the Shell/Esso 49/19a Clipper topside structure.  
The Heeremac DB 102 can be seen waiting in the background.

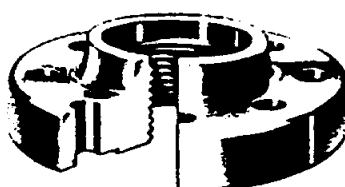


# STAINLESS STEEL FORGED FLANGES

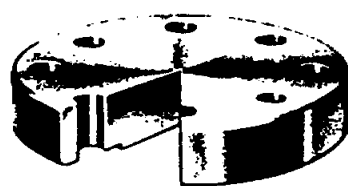
Size Range 1/2" to 48" NPS



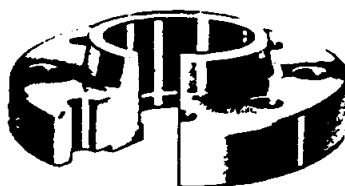
Slip-On  
200



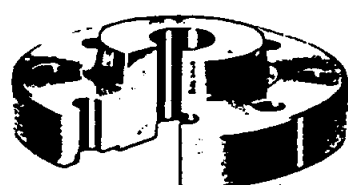
Screwed  
201



Blind  
202



Socket Weld  
203



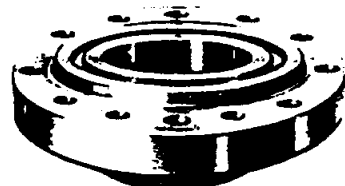
Reducing  
205



Weld Neck  
206



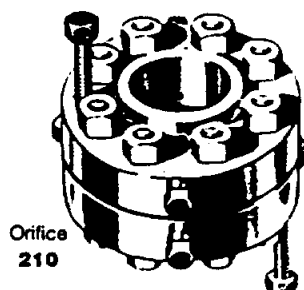
Lap Joint  
209



Ring Type Joint  
207



Spectacle  
208



Orifice  
210



Long Weld Neck  
204

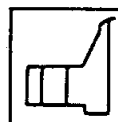
## FLANGE FACING:



CLASS 150  
& 300 RF



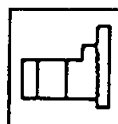
CLASS 400 &  
UPWARD RF



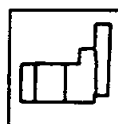
MALE



FEMALE



THREADED  
MALE



THREADED  
FEMALE



TONGUE



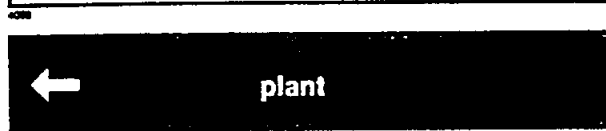
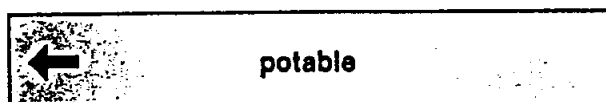
GROOVE



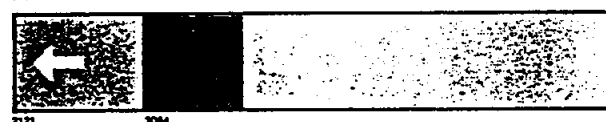
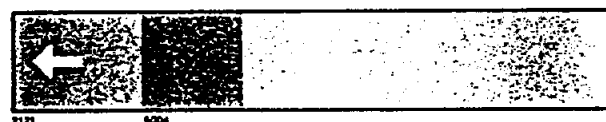
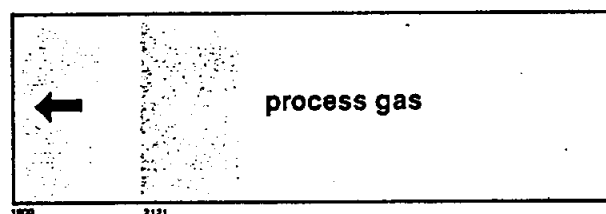
RING JOINT

## COLOUR CODING FOR PIPEWORK

### WATER



### GAS



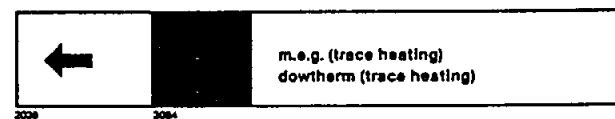
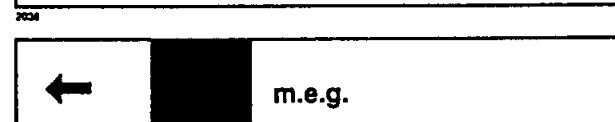
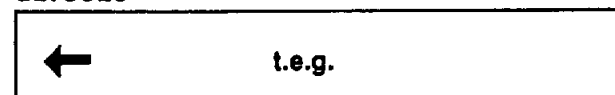
### DRAINS & VENTS



### OILS



### GLYCOLS

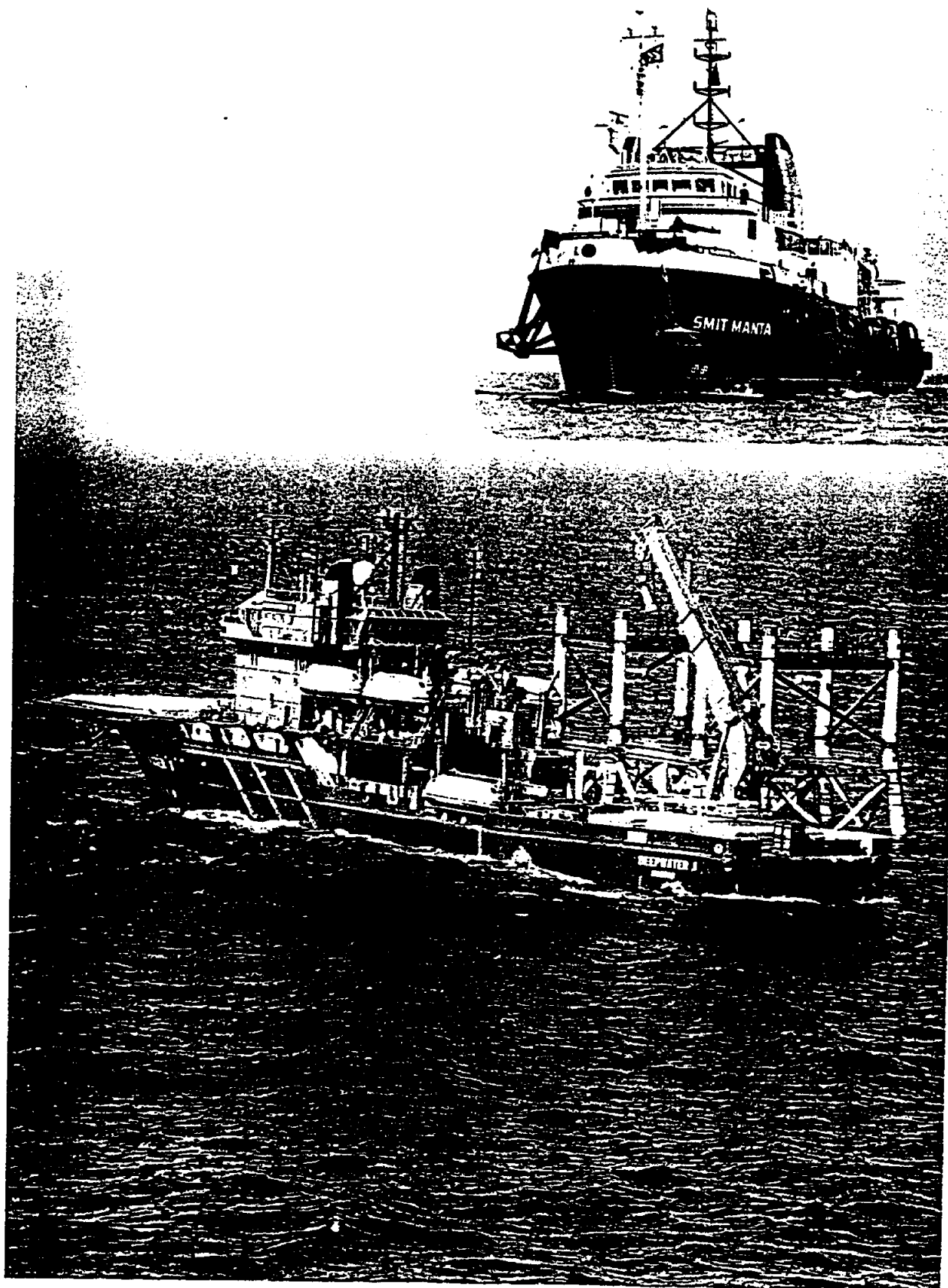


### AIR



NUMBERS REFER TO HEMPELS COLOUR CODE





13 - The equipment .....

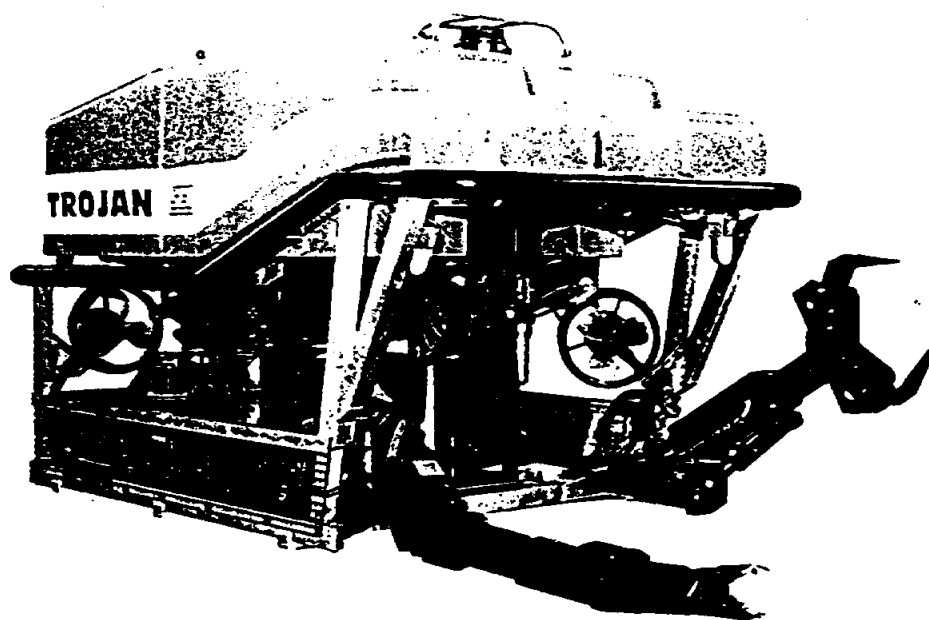
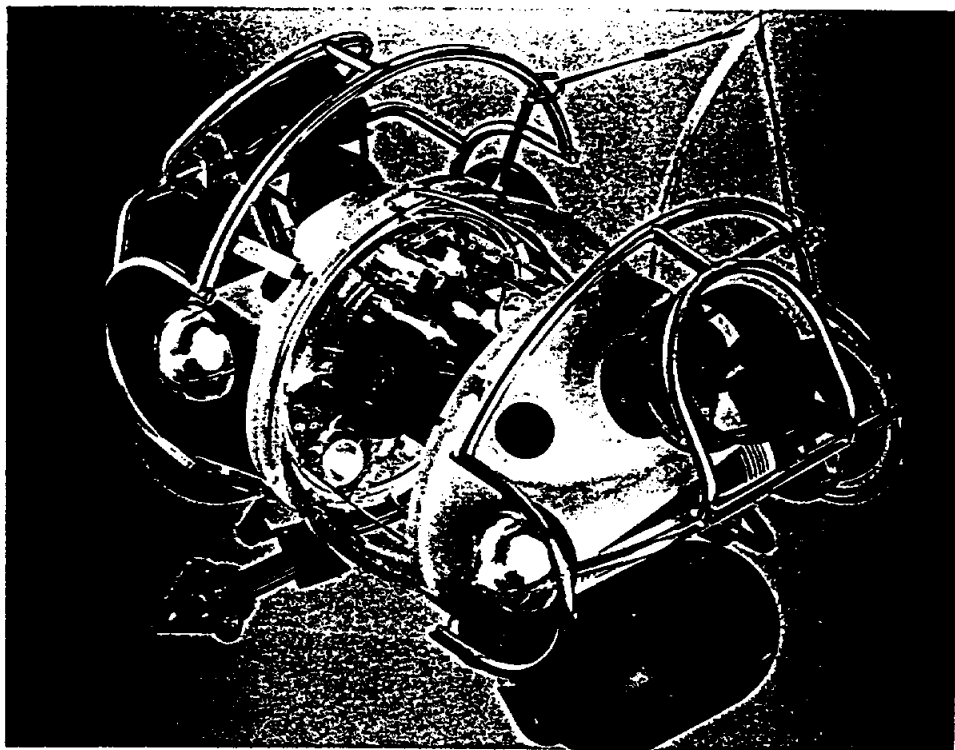
State of the art diving support vessel the Deepwater 1 involved in survey work during the installation of a jacket.  
Inset - the rugged splendour of an offshore supply boat equipped for diving support duties, the Smit Manta.



14 - The men .....

*Typical North Sea air diving dry suit and associated attire.*

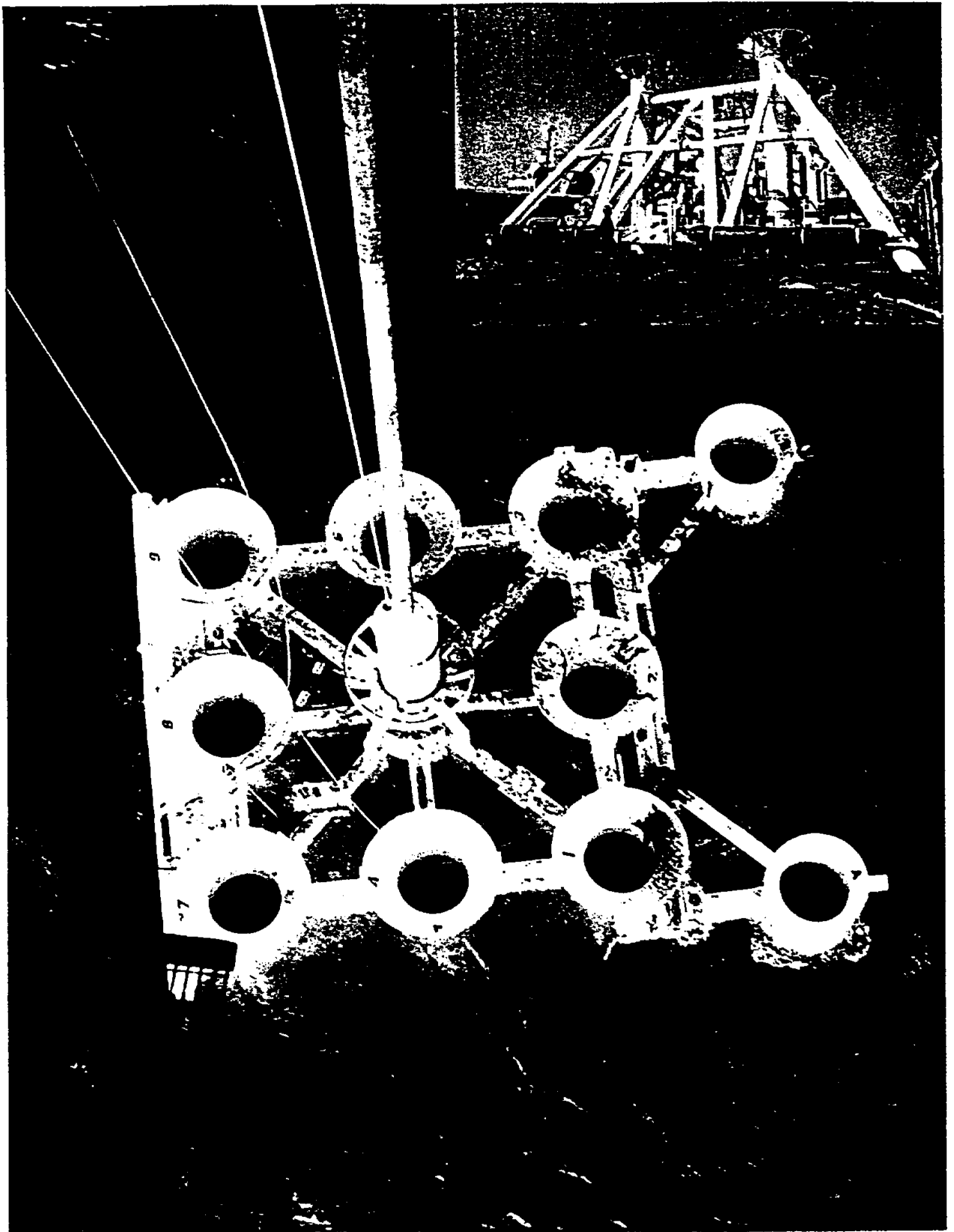
*Inset - the spartan interior of an air diving deck decompression chamber.  
The diver can be seen inhaling oxygen to accelerate the decompression process.*



*15 - The competition .....*

*The Offshore Hyball, a lightweight Remotely Operated Vehicle (ROV) equipped with video monitoring inspection equipment.  
Courtesy of Hydrovision Limited.*

*The Trojan Remotely Operated Vehicle (ROV).  
The propeller thruster units and articulated manipulators are clearly visible.  
Courtesy of Slingsby Engineering Limited.*



16 - The task .....

The installation of a drilling template. The template is being installed on the end of a drill string from a jack-up.

The template has slots for 9 wells and there are two pile guides.

Inset - subsea wellhead protection frame loaded on to the deck of an offshore supply boat for transportation to its final resting place.

## **Part 4. NAVIGATIONAL AIDS** **(fixed offshore installations)**

As a means towards providing protection against shipping, every offshore installation must be fitted with visual and audible navigational aids in accordance with the requirements of a schedule provided by the Department of Transport under the Coast Protection Act 1949.

### **1. VISUAL NAVIGATION AIDS**

#### **WHITE LIGHTS**

It is a requirement that a flashing white light can be seen from whichever direction an installation is approached.

A light intensity of 12,000 Candela is specified which will give a range of approximately 15 miles (24 Km.). Should the bulb filament fail then a secondary bulb should illuminate automatically and activate an alarm.

The lights which are normally mains powered are to be provided with an independent secondary source of power (normally batteries) capable of ensuring uninterrupted operation for a period of 4 days (96 hours). In the event of a mains power failure the change over to the secondary power supply should take place automatically and initiate an alarm at the main control station.

#### **RED LIGHTS**

It is a requirement that the horizontal extremities of an installation be illuminated with flashing red subsidiary lights. A red light need not be fitted to an extremity where a white light already exists.

A light intensity of 1,200 Candela is required which will give a range of approximately 3 miles (4.8 Km.).

#### **LIGHTING - GENERAL**

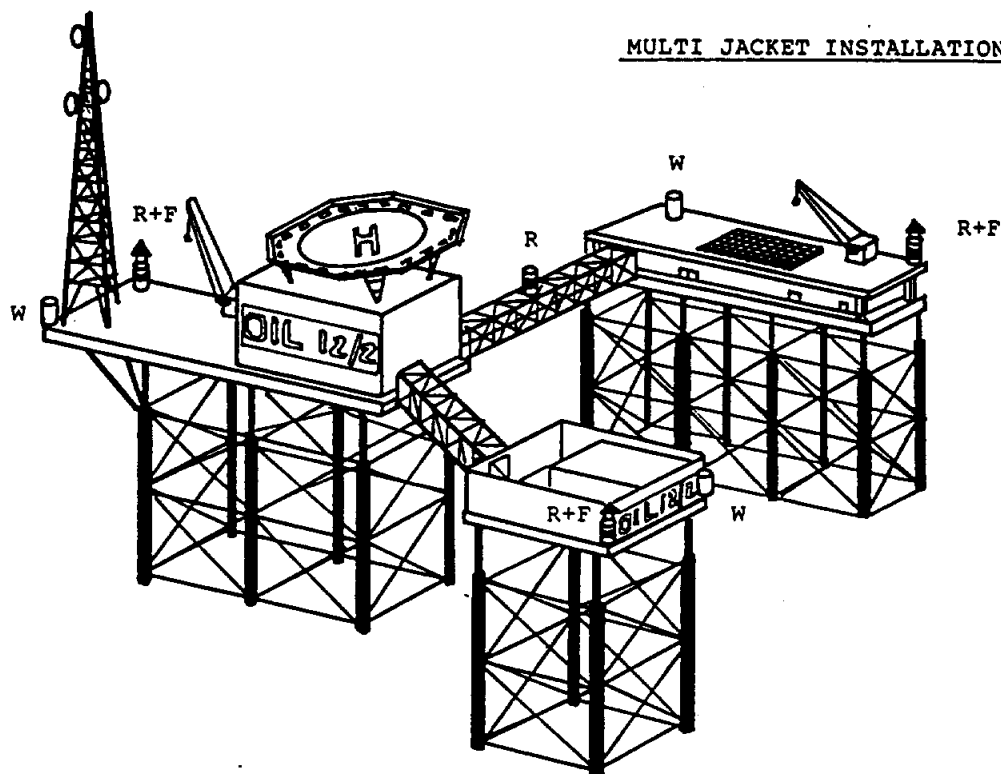
The sketches show typical arrangements. Two white and two red lights will normally suffice per installation (not per jacket).

The white lights must flash in unison. The red lights must also flash in unison but they need not flash in unison with the white lights.




The lights shall spell the letter 'U' in morse code every 15 seconds. They should be mounted at a position between 12 and 30 metres (40 and 100 feet) above sea level in order that maximum visibility is obtained.

The lights shall be exhibited from 15 minutes before sunset until sunrise and at all times when meteorological visibility is less than 2 miles (3.2 Km.).

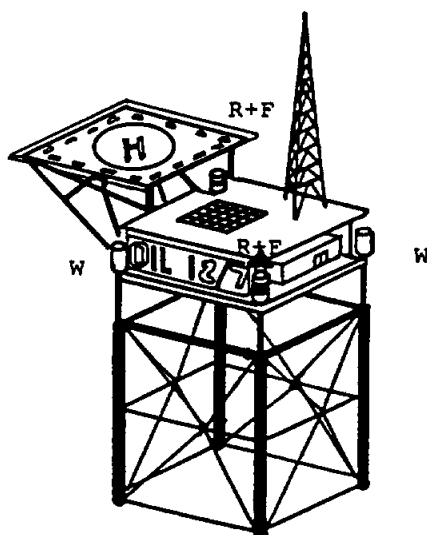
MULTI JACKET INSTALLATION



KEY

-  Red light
-  White light
-  Fog horn

SINGLE INSTALLATION



NAVIGATIONAL AIDS

## 2. AUDIBLE NAVIGATIONAL AIDS

Fog signals shall be sounded whenever meteorological visibility falls below 2 miles (3.2 Km.).

The fog signal shall spell the letter 'U' in morse code over a period of 30 seconds and have a range of at least 2 miles.

The primary fog signal which may be mains powered is to be provided with a secondary fog signal which will commence operation automatically on failure of the primary system and initiate an alarm at the main control station. The secondary system must have a range of at least half a mile (800 metres).

The main and secondary fog signals shall each be capable of operating continuously at full power for at least four days (96 hours) from a power source independent of the mains supply (normally batteries).

The secondary power supplies for navigation aids are to be located within compartments structurally protected against fire to A-60 requirements.

## 3. NAVIGATION AID FAILURE

If a total failure of the navigational aids occurs the installation must be temporarily marked by one of two methods:

- i. A temporary battery powered system of lights and fog signals must be installed which meets the requirements for light and fog secondary systems.
- ii. Two cardinal buoys are to be located on either side of the installation at one cables length from the rig.

The buoys must be fitted with a light with an intensity of not less than 70 Candela and a fog horn consisting of a wave activated whistle or bell.

## 4. IDENTIFICATION PANELS

Identification panels are to be fitted which display a registered name or unique number by which the installation is registered. Figures should be 1 metre (40 inches) high on a yellow background and be so arranged that one panel is visible from any direction.

The panels are to be illuminated or constructed from retro-reflective materials.

The helideck must also be clearly identified with the installation name and number.

## **Part 5. MAINTENANCE AND REPAIR**

**INTRODUCTION** - As one might imagine, the problems associated with operating an offshore installation in one of the harshest environments in the world are considerable.

The planned maintenance, modification and repairs required to keep an installation at peak operating performance for a period of approximately 25 years present a logistical nightmare for those involved with the planning of such operations. There is an abundance of mechanical, electrical and instrumentation equipment which requires continual attention from numerous specialised trades. Even tasks such as painting the structure require considerable planning and additional precautions when compared with similar projects carried out onshore.

Some of the requirements the offshore operators must comply with whilst carrying out these projects are specified in Statutory Instrument No. 1019 - Offshore Installations (Operational Safety, Health and Welfare) Regulations 1976, and Statutory Instrument No 2885 - Offshore Installations (Safety Case) Regulations 1992.

### **1. MAINTENANCE**

The regulations require that a planned maintenance system be in operation that will cover each and every part of an offshore installation and its equipment. Written records of the examinations carried out are to be maintained for a period of at least two years.

The SI 1019 treats lifting appliances as a separate category of equipment and requires each and every item to be examined and certified by an independent competent body at 6 monthly intervals.

### **2. SAFETY OF EQUIPMENT**

SI 1019 requires that potentially dangerous parts of machinery and apparatus are to be effectively guarded against injury to personnel. Written instructions are to be provided in respect of the safe operation of the installation and the use of equipment thereon. Requirements are also specified for the handling of dangerous substances which are radioactive, corrosive, toxic or explosive.

### **3. PERMIT TO WORK (PTW)**

One of the most important sections of SI 1019 (and SI 2885) relates to the operation of a permit to work system.

Due to the continual presence of hydrocarbon products it is vitally important that caution is exercised when undertaking work that could create a source of ignition.

The PTW system must be rigidly enforced, particularly during major modification or repair programmes. These projects often involve large numbers of contract tradesmen who may be unfamiliar with the hazards involved with working offshore.



## STATUTORY EQUIPMENT

The permit to work system involves the use of written permits to ensure that potentially dangerous jobs are carried out safely. The permits must be issued by a competent person who is fully conversant with the task in hand and the precautions required. The permit must state the extent of the work, any isolation necessary and any additional safety precautions that must be complied with. The work space should be examined before work commences and re-examined by a competent person when the work is considered to be complete and the equipment reinstated.

The PTW system frequently utilises different colour permits depending on the nature of the work. Hot work may be written on a pink form, cold work on a blue and electrical on a green.

Hot work may be further categorised into tasks which involve a positive source of ignition, and tasks which have the potential to create a source of ignition. Category 1 tasks include flame cutting, grinding and welding, and typical Category 2 tasks are shot blasting, chipping and caulking. The majority of routine maintenance and repair duties will be covered by cold work permits.

Further guidance on the subject of permit to work permits can be found in the following publications;

- i) Guidance on Permit to Work Systems in the Petroleum Industry (Health and Safety Commission/Oil Industry Advisory Committee, 1991).
- ii) Isolation of Process Plant - Planning, Execution and Recording, HSE/OSD Safety Notice 8/91.

## Part 6. HAZARDOUS AREAS

An offshore installation is divided into regions or zones depending on the likelihood of an explosive gas/air mixture developing. These zones may be either hazardous or non-hazardous and their location will be clearly marked on a general arrangement drawing of the installation which can be found in the Statutory Operations Manual.

Hazardous area classification was originally developed to provide guidelines for the selection of electrical equipment within onshore oil refineries. It has since been adapted to fulfil a similar role on offshore installations for electrical and mechanical equipment.

### 1. NON-HAZARDOUS AREAS

Non-hazardous or safe areas are those locations where explosive hydrocarbon mixtures are not expected to occur in sufficient quantities to present a hazard.

It should be noted that it is a requirement for all accommodation spaces to be located in a safe area.

### 2. HAZARDOUS AREAS

Hazardous areas are sub-divided into 3 categories.

- i) Zone 0 - an area in which an explosive gas/air mixture is continuously present, or present for long periods.

It is unlikely that a Zone 0 area would be encountered offshore and should it exist then all electrical equipment should be excluded. Where this is impractical, intrinsically safe components may be used.

- ii) Zone 1 - an area where an explosive gas/air mixture is likely to occur during normal operating conditions.

Such regions occur around flare booms and vent stacks. If a circle is drawn with its centre at the gas source and with a radius of 15 metres (50 feet), then all regions within this circle will be classed as Zone 1. The zone will extend vertically upwards a distance of 3 metres (10 feet) and vertically downwards to the sea level for gases which are heavier than air such as methane, the primary constituent of natural gas.

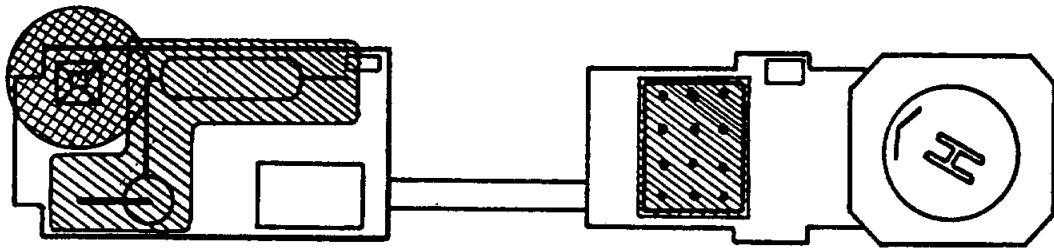
All electrical equipment within a Zone 1 area should be suitably certified (see reference chart). All electrical cables should be protected with a metallic sheath with the addition of a non-metallic impervious sheath.

It is permissible to use non-certified equipment in a Zone 1 area provided that the equipment is located within a positively pressurised (5 mm water gauge) compartment which is ventilated with air supplied from a safe area. An interlock must be fitted which will de-energise all uncertified electrical equipment and initiate an alarm in the main control room if a failure of the pressurisation occurs. Under these circumstances the compartment can be considered to be a safe area.

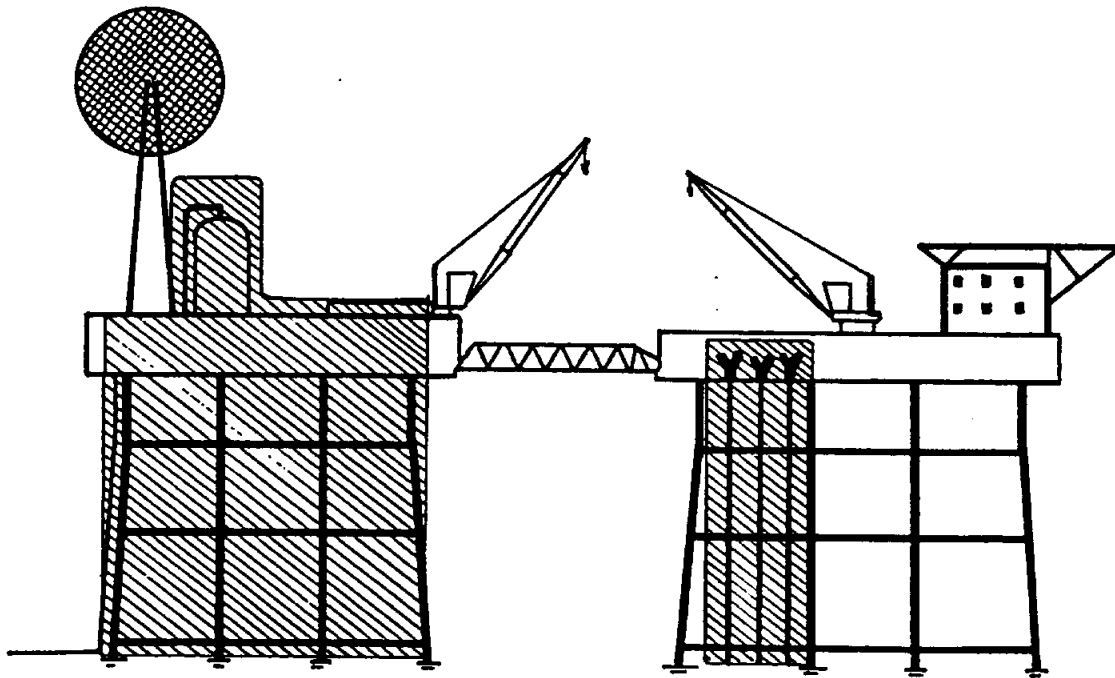
STATUTORY EQUIPMENT

Production Platform

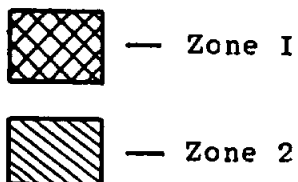
Wellhead/Accommodation  
Platform



PLAN



ELEVATION



HAZARDOUS AREAS

All doors leading from a Zone 1 area into a non-hazardous area should be fitted with an airlock. If this is not practical then the heating, ventilation and air-conditioning (HVAC) system should be fitted with a standby fan which will start automatically on loss of pressurisation.

- iii) Zone 2 - an area where an explosive gas/air mixture is not likely to occur, and if it does, will only exist for a short period of time.

Gas processing areas, wellheads and parts of the drill floor are all normally classed as Zone 2 areas and all electrical and mechanical equipment should be suitably certified.

The hazardous area is normally considered to extend a horizontal distance of 7.5 metres (25 feet) from gas handling equipment and vertically downwards to the sea level.

Some latitude exists as to the determination of hazardous area boundaries depending on which guidelines a company has based its philosophy. New installations should comply with BS 5345 Part 2 - Classification of Hazardous Areas. Older installations tended to use the Institute of Petroleum Model Code of Safe Practice, Part 1 1965.

Open deck areas of North Sea installations are well ventilated by prevailing winds and natural draughts which prevent the build up of large quantities of gas. All distances so far quoted for hazardous area boundaries are based on these open deck conditions. Enclosed areas must be considered separately because of the possibility of a build up of gas occurring.

### **3. ENCLOSED COMPARTMENTS - ZONE 2 AREAS**

- (a) An enclosed area in which it is possible for an explosive gas/air mixture to develop under abnormal conditions must be classed as Zone 1. In addition the surrounding areas for a distance of 7.5 metres (25 feet) will be considered to be a Zone 2 area.

The enclosed area may be considered a safe area if it is suitably ventilated and pressurised (5 mm water gauge).

- (b) An enclosed area which does not contain a source of hazard must be classed as a Zone 1 area unless suitable ventilation and pressurisation systems are fitted.

It is recommended that all access points which either:

- i. lead from a Zone 1 area into a Zone 2 area or,
- ii. lead from a Zone 2 area into a non-hazardous area,

should be constructed with a two door airlock. If this is impractical, gas tight self-closing doors must be fitted.

All doors leading from a safe area to a hazardous area should bear the legend HAZARDOUS AREA in letters approximately 50 mm (2 inch) in height.

#### 4. EQUIPMENT IDENTIFICATION

It is a requirement that all electrical equipment installed within hazardous areas should be certified as suitable for the location. This certification will be issued by BASEEFA (British Approval Service for Electrical Equipment in Flammable Atmospheres) as a result of type approval tests that they have carried out on each component. An identification plate attached to the component will provide information as to the suitability of the equipment for installation in a particular environment.

Equipment should be selected in accordance with the following reference guides.

##### i) LOCATION

###### a) Zone 0

Preferably no electrical equipment. If fitted it must be:

Intrinsically safe	Ex ia
Specially Certified for Zone 0	Ex s

###### b) Zone 1

All equipment suitable for Zone 0 areas, and:

Special apparatus	Ex s (specially certified)
Flameproof	Ex d
Intrinsically safe	Ex ib
Pressurised	Ex p
Increased safety	Ex e
Encapsulation	Ex m

###### c) Zone 2

All equipment suitable for Zone 0 and Zone 1, and:

Non-incendive	Ex N or n
Oil immersed	Ex O
Powder/Sand filled	Ex q

##### ii) TEMPERATURE RATING

Hazardous area equipment will also display identification as to its suitability for use at elevated temperatures (over 40 deg. C ambient) and with various gases.

###### Temperature Selection (Temperatures in °C)

T1 450	T4 135
T2 300	T5 100
T3 200	T6 85

###### Gas Types

Methane	1
Propane	11A
Ethylene	11B
Hydrogen	11C

An example, a piece of equipment marked as Ex d 11 B T5 would be suitable for use with flammable gases such as Ethylene, Propane and Methane provided that the ignition temperature of any gas to be used is not less than 100°C (T5).

### iii) INGRESS PROTECTION (IP)

The IP ratings system has been included in this chapter for general information only. It does not apply to hazardous area equipment because of the limited protection offered. It will, however, be frequently encountered offshore on items of equipment such as junction boxes.

Two numbers are used. The first number indicates protection against solid bodies, whilst the second number indicates protection against liquids, e.g. IP 54, protected against dust and splashed water.

0	No protection	0	No protection
1	Objects > 50 mm	1	Vertically dripping water
2	Objects > 12 mm	2	75-90° angled dripping water
3	Objects > 2.5 mm	3	Sprayed water
4	Objects > 1.0 mm	4	Splashed water
5	Dust-protected	5	Water jets
6	Dust-tight	6	Heavy seas
		7	Effect of immersion
		8	Indefinite immersion

### REFERENCE STANDARDS

1. Department of Energy Offshore Installations: Guidance on Design Construction and Certification.
2. BS 5345 Classification of Hazardous Areas and Selection of Equipment for use in Hazardous Areas.
3. Institute of Petroleum Code of Safe Practice Part 1, 1965.
4. BS 4683 Electrical Apparatus for Explosive Atmospheres.
5. BS 5501 Electrical Apparatus for Potentially Explosive Atmospheres.
6. BS 4137 Guide to Selection of Equipment for use in Division 2 Areas.
7. BS 5490 Specification for Degrees of Protection Provided by Enclosures.
8. API RP 500 Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs on Land and on Marine, Fixed and Mobile Platforms.

### ALTERNATIVE EQUIPMENT TESTING AUTHORITIES

France	CERCHAR, LCIE
Italy	CESI
Belgium	INIEX
Germany	PTB, BVS
Denmark	DEMKO
U.S.A.	Underwriters Laboratory (UL) Factory Mutual
Canada	CSA

## **Chapter Four**

### **PIPING SYSTEMS AND PROCESS PRESSURE VESSELS**

#### **PART 1. PIPING SYSTEMS**

1. Hydrocarbon Process
2. Utility

#### **PART 2. PROCESS PRESSURE VESSELS**

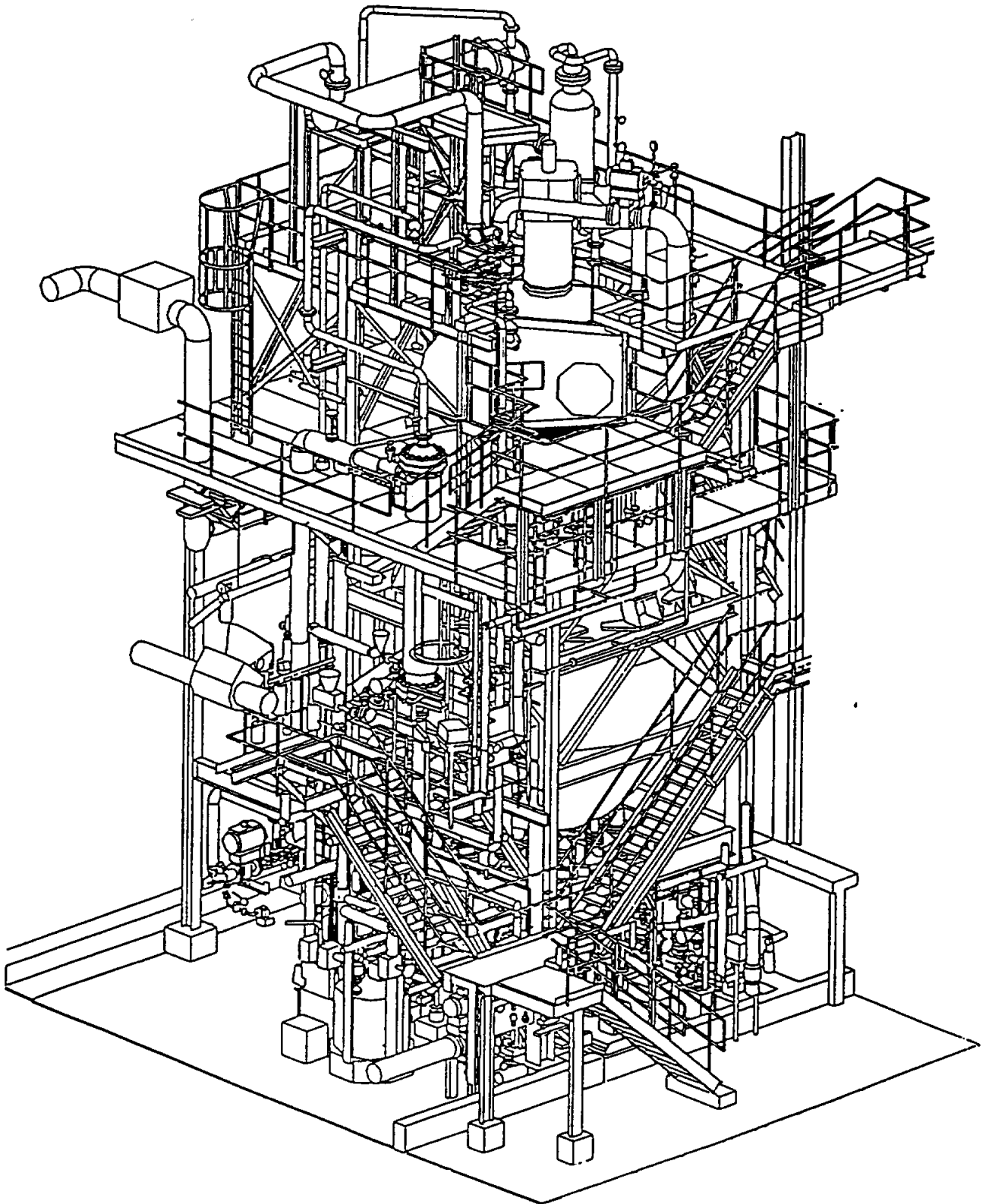
1. Gas/oil/water Separators
2. Gas/liquid Separators
3. Oil/water Separators
4. Holding Tanks

#### **PART 3. PIPING AND PRESSURE VESSEL DESIGN**

1. Piping Systems - Installation and Layout
2. Piping Systems - Design
3. Pressure Vessels - Design

#### **PART 4. PIPING SYSTEMS - CONSTRUCTION**

1. Pipe
2. Fittings
3. Valves



**COMPUTER GENERATED DRAWING OF PROCESS PRESSURE VESSEL  
AND PIPEWORK**  
(Kvaerner Cape Surveys)



## **Part 1 PIPING SYSTEMS**

The piping systems on an offshore installation may be divided into two basic categories.

1. Hydrocarbon process
2. Utility

All pipework should be colour coded to assist in system identification and the coding system particulars and P & ID'S ( piping and instrumentation diagrams) can be found in the Statutory Operations Manual.

### **1. HYDROCARBON PROCESS**

#### **i) GAS/OIL PROCESS**

The main objective of an offshore installation is to separate hydrocarbon products into liquid or gaseous forms and to remove any impurities that will inhibit transportation.

A more detailed account of the gas and oil production processes can be found in Chapter Five.

#### **ii) CONDENSATE**

Condensate is a clear highly volatile liquid produced as a bi-product of the gas production process. The condensate system is primarily concerned with the removal of water prior to the injection of the condensate into the gas subsea pipeline for transportation to the onshore reception facility.

#### **iii) FUEL GAS**

Electrical power on an offshore installation is generated by either gas turbine driven, or gas engine driven alternators. Both systems run on process gas as do the glycol reboilers. The fuel gas is taken either from the main outlet header, or produced as a bi-product of the various refinement processes and is subject to further separation, drying and filtration before entering the fuel gas main.

#### **iv) POWER GAS**

Older installations frequently utilise process gas to provide the motive power for the actuation of valves. New installations tend to favour hydraulics or compressed air systems which create fewer restrictions on hazardous area boundaries.

#### **v) VENT SYSTEM**

Vent systems are generally associated with gas production installations and both high (HP) and low (LP) systems are employed.

- a) The HP vent system is used primarily to depressure process pressure vessels during an emergency shutdown (ESD) situation, or to relieve excess vessel pressure via pressure safety valves (PSV).

The system consists of a large diameter main, a knock out (KO) drum or separator vessel designed to remove entrained liquids, and a vertical pipe or vent stack that will release the gas to atmosphere at a safe location above the installation. The vent system is continuously purged with gas to ensure that a rich, and thus non-explosive atmosphere prevails, and it is protected against fire by a dry powder, carbon dioxide, or halon equipped fixed fire fighting system.

- b) The LP vent system is virtually a duplicate of the HP vent system designed to operate at lower pressures. The system provides a route for the release of gases from PSV's and atmospheric vents.

#### vi) FLARE SYSTEM

The flare system fulfils a similar function to the vent system, the obvious difference being that the gas is ignited as it leaves the end of the flare boom.

The flare system will only be encountered on oil production installations where the quantities of gas requiring disposal are often considerable and would constitute a hazard if simply released into the atmosphere through an open vent.

#### vii) CORROSION INHIBITOR

The use of a corrosion inhibitor provides some protection to the carbon steel pipework. The inhibitor, frequently Cronox 638S is mixed with methanol or MEG (20%/80%) and may be injected into wells, process plant and subsea pipelines.

#### viii) HYDRATE INHIBITOR

Both methanol and monoethylene glycol (MEG) are used extensively by the offshore industry to combat hydrate formation. They may be injected into the process plant on an occasional basis during periods of peak gas production, or continuously metered into the subsea pipeline, a practise frequently encountered on small satellite platforms devoid of water separation equipment. The inhibitors are eventually recovered from the "wet gas" at the onshore reception facility or at the mother platform.

When employed on an occasional basis stocks can be replenished by supply boat (bunkered) but the quantity consumed by continuous pipeline metering necessitates the installation of a small diameter (4 inch/100mm) subsea pipeline which is attached (pickaback or piggy-backed) to the main gas export line so that inhibitor can be supplied direct from the onshore reception facility or the mother platform.

Prior to use the inhibitors are stored in atmospheric tanks, the methanol tanks frequently employing a blanket of fuel gas to reduce the air space and thus the flammability.

- a) **Methanol.** Flash point 16°C/60°F. Methanol is without doubt the most effective of the hydrate inhibitors and it is the only inhibitor capable of melting a hydrate, should one occur. For this reason reserves of methanol may be encountered on installations which rely primarily on MEG for routine hydrate inhibition. Methanol's effectiveness as an inhibitor is due primarily to its willingness to vaporise, for to be effective an inhibitor must be delivered to the location where condensation is likely to occur. Unfortunately this characteristic hinders the separation of the methanol at the onshore reception facility and up to 50% of the methanol is unrecoverable. Heavy methanol consumption can prove both expensive and upsetting to subsequent items of process equipment.

- b) **Monoethylene glycol (MEG).** Flash point 116°C/240°F, boiling point 197°C/388°F, freezing point -13°C/9°F.

Monoethylene glycol is hygroscopic, that is to say it has a strong affinity for water. Up to 90% of the MEG injected into the gas stream can be recovered at the onshore reception facility and as such it makes an efficient and economic hydrate inhibitor.

- c) **Triethylene glycol (TEG).** Flash point 160°C/320°F, boiling point 288°C/550°F, freezing point -7°C/20°F.

Triethylene glycol is not generally employed as a hydrate inhibitor being more suited as a drying agent in a dehydration process where it is chosen in preference to other glycols because of its ability to withstand the elevated temperatures associated with the re-generation process.

## 2. UTILITY SYSTEMS

### i) FIREWATER

The firewater system can be extremely complex, particularly on large installations and the subject is discussed in greater detail elsewhere.

### ii) SEAWATER SERVICE

In its simplest form the seawater service system consists of a small diameter (4 inch/100mm) ring main which is maintained at a constant pressure by an electrically powered deepwell submergible pump. The water is used primarily for wash down purposes and for the flushing of domestic toilets but it also maintains the firewater ring main at a constant pressure of approximately 100 psig (7 bar) to ensure an instantaneous supply of water prior to the activation of a fire pump.

The general service seawater system associated with a large oil production installation is considerably more complex than that previously described. It is often the largest single piping system on the platform supplying water to the utility and production process coolers and also to the enhanced oil recovery plant.

### iii) SODIUM HYPOCHLORITE

Sodium hypochlorite solution is frequently injected into seawater pump suctions to combat the growth of marine organisms and algae that contribute towards the fouling of filters and pipelines.

The sodium hypochlorite is produced by the electrolysis of seawater within a hypochlorite generation cell, the seawater being forced to flow between two concentric titanium tubes which are connected to a d.c. (direct current) power supply. The resulting sodium hypochlorite solution is extremely corrosive and must be stored in stainless steel or GRP (glass reinforced plastic) tanks prior to use. The electrolysis of seawater also produces hydrogen gas but the quantities generated are insufficient to constitute a hazard provided that the storage tanks are located in a well ventilated open deck area.

iv) **POTABLE WATER**

Potable water for domestic consumption is stored in fresh water tanks and supplied to the accommodation via a pressurized surge vessel. Fresh water may be bunkered from supply boats, or produced from seawater by desalination, or reverse osmosis plants.

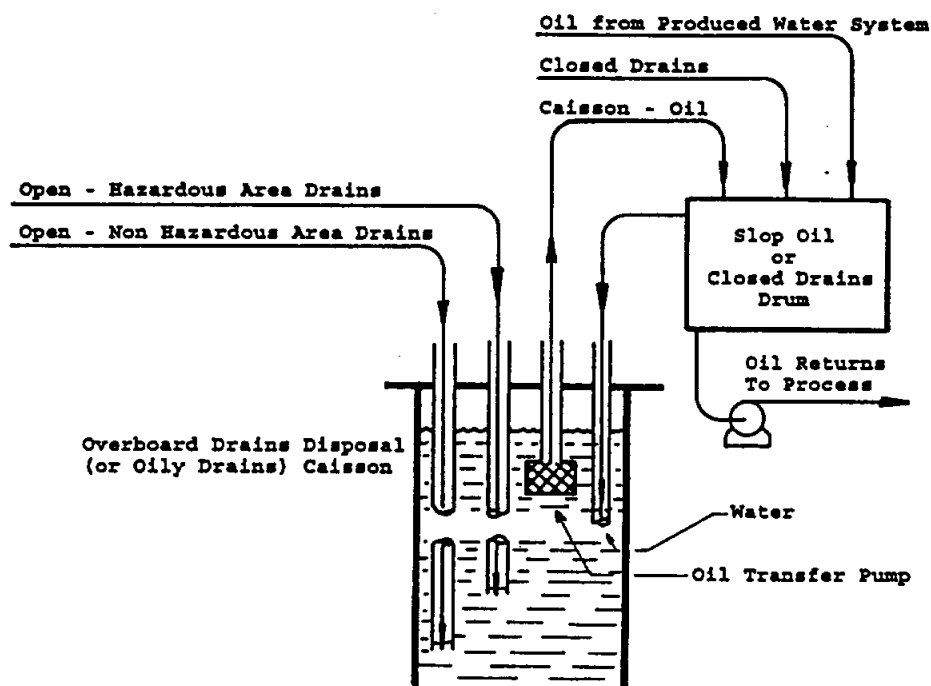
v) **COMPRESSED AIR**

The compressed air is normally supplied from large air receivers which are maintained at a constant pressure of approximately 100 psig (7 bar) by multi-stage reciprocating air compressors. The discharge manifold connecting the air receivers divides into two separate systems.

- a) **Instrument air.** It is most important that the vast array of delicate instruments employed on a modern installation are provided with a supply of clean, dry air if they are to function reliably. Consequently, air drawn from the main air receivers passes through an electrically heated desiccant drying medium and fine filtration package prior to entry into the instrument air main.
- b) **Utility air.** Utility air is provided for various operations such as the starting of diesel engines and pressurising of water distribution vessels. Hand tools, pumps and other items of portable equipment can be operated from hose stations located throughout the installations.

vi) **DIESEL FUEL**

Cranes, lifeboat, standby and emergency generators are all powered by diesel engines and diesel consumption can be quite considerable, particularly during process shut down periods when fuel gas is unavailable. The diesel oil is bunkered from supply boats and may be stored in purpose built tanks or in structural void spaces such as crane pedestals and jacket legs.



**DRAINS SYSTEMS - Older Installations**

### vii) HELIFUEL

A number of offshore installations provide helicopter refuelling facilities. The aviation spirit is delivered and stored in purpose built fuel tanks by supply vessels.

### viii) DRAINS

The design of a drainage system on an offshore installation is yet another area which reflects individual company philosophy and the lack of standardisation often leads to confusion. However, the basic function of the system is to ensure that pollutants are removed from waste waters prior to their discharge into the sea.

The drainage system may be divided into three categories:-  
open drains, closed drains and sewage disposal system.

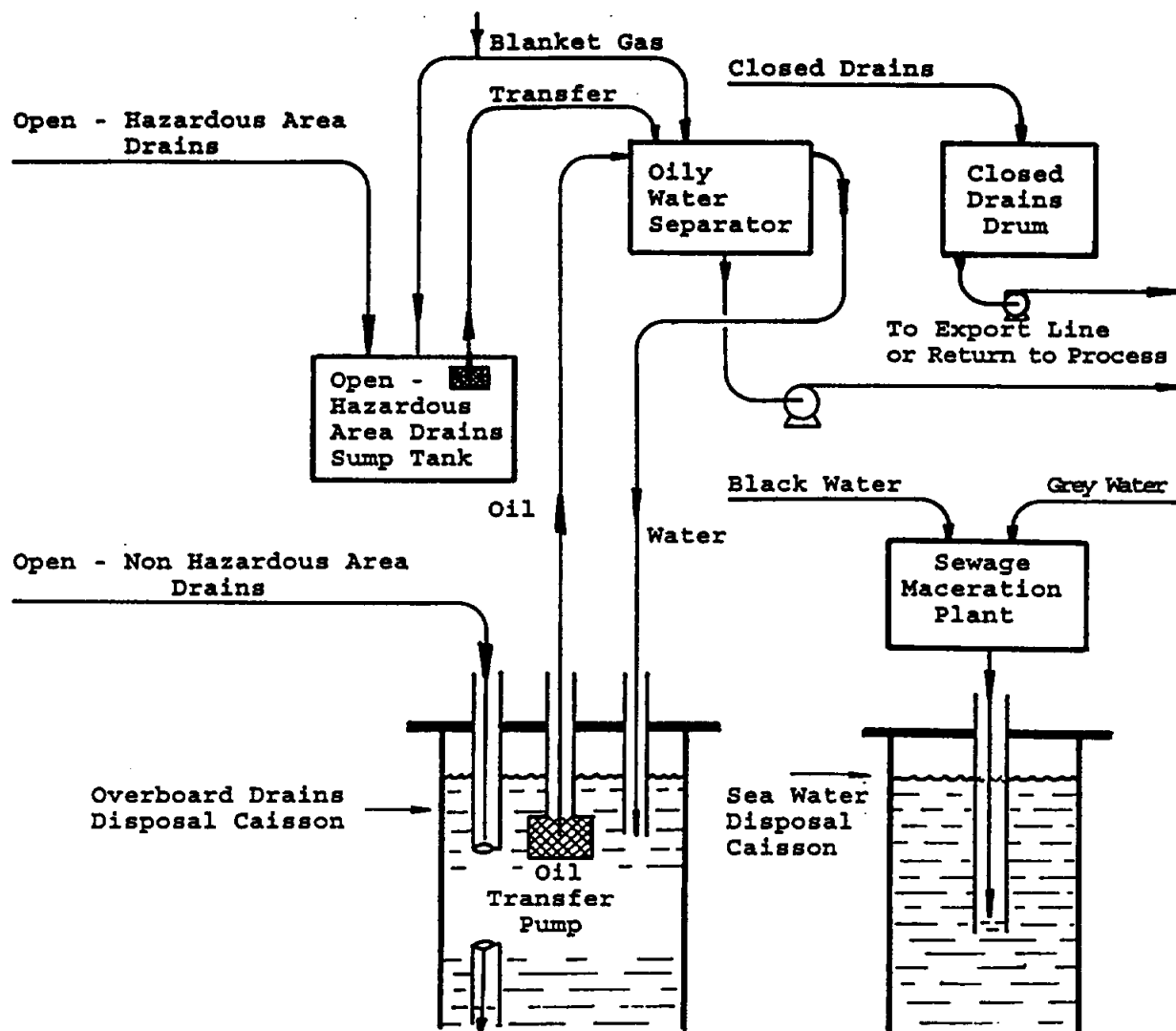
- a) **Open drains - Non-hazardous.** A less confusing title would be Safe Area Open Drains because the system simply provides for the removal of surface deck water from locations designated as safe areas. The waters are relatively free of contaminants and are piped directly into the overboard drains disposal caisson, a discharge pipe extending into the sea a distance of approximately 25 metres ( 90 feet ).

**Open drains - Hazardous.** In practice these drains rarely constitute a hazard but they are named as such because they originate from within locations designated as hazardous areas. They consist primarily of water wash, rain and deluge waters and may take one of two directions depending on the age of the installation.

Generally speaking, the hazardous area open drains on installations constructed prior to 1985 are discharged directly into the overboard drains disposal caisson alongside the non-hazardous open drains. In order to reduce the possibility of contaminating safe areas with potentially hazardous substances the hazardous area drains discharge pipe is terminated above the non-hazardous area drain discharge pipe, both being submerged in sea water. On newer installations the hazardous open deck drains are collected in a dedicated hazardous area open deck drains sump tank, thus entirely eliminating the possibility of contaminating safe and hazardous area drains. The hazardous area open drains sump tank acts purely as a holding vessel, the contents being transferred to the oily water separator (OWS) where the differences in the specific gravities of the oil and water are used to effect separation. The water gravitates into the open drains caisson whilst the oil is pumped into the gas export line or returned to the process plant.

The open drains disposal caisson provides a final opportunity for any remaining condensate/oil to separate from the water. The oil floats to the top of the caisson where it can be transferred into the slop oil tank or the oily water separator by a pump which operates automatically activated by an oil/water interface sensor. An oil content of less than 40 ppm is required before the water can be discharged into the sea.

- b) **Closed drains -** The closed drains system provides the means by which a process vessel may be manually emptied and should not be confused with the produced water system which provides for the automatic removal of liquids separated from the gas/oil production process. The vessel drains are used on an occasional basis whilst the produced water system is in constant use and may be used to dispose of quantities of water varying from several tons to several thousand tons a day.



### DRAINS SYSTEMS - Newer Installations

The closed drains system consists of a number of separate collection headers ( pipelines ) which are graded in accordance with the pressure ratings of the pressure vessels that they serve, the headers being protected against over pressure by restrictive orifice plates located in the vessel outlets. The headers terminate within the slop oil tank, or a dedicated closed drain drum, depending on the design of the system.

The slop oil tank featured on older installations frequently permits a degree of water/oil separation with the water gravitating to the overboard drain disposal caisson whilst oil products are disposed of in the same manner as the contents of the closed drains drum, that is pumped into the export line or back into the process system for re-circulation.

- c) **Sewage system** - The sewage system can be divided into Grey water which consists of drainage water from showers and sinks, and Black water or raw sewage. Both systems combine prior to their entry into the sewage maceration plant and subsequent discharge into the seawater disposal caisson.

## Part 2 PROCESS PRESSURE VESSELS

**INTRODUCTION** - The vast majority of process vessels employed on an offshore installation are remarkably simple in design and rely on very basic principles of fluid dynamics to effect the separation of oil (or condensate), gas, water and sand.

Generally speaking the vessels are common to both oil and gas production installations and with the exception of the specialist dehydration, NGL removal, stabilisation and sweetening system vessels, they fall into four main categories:-

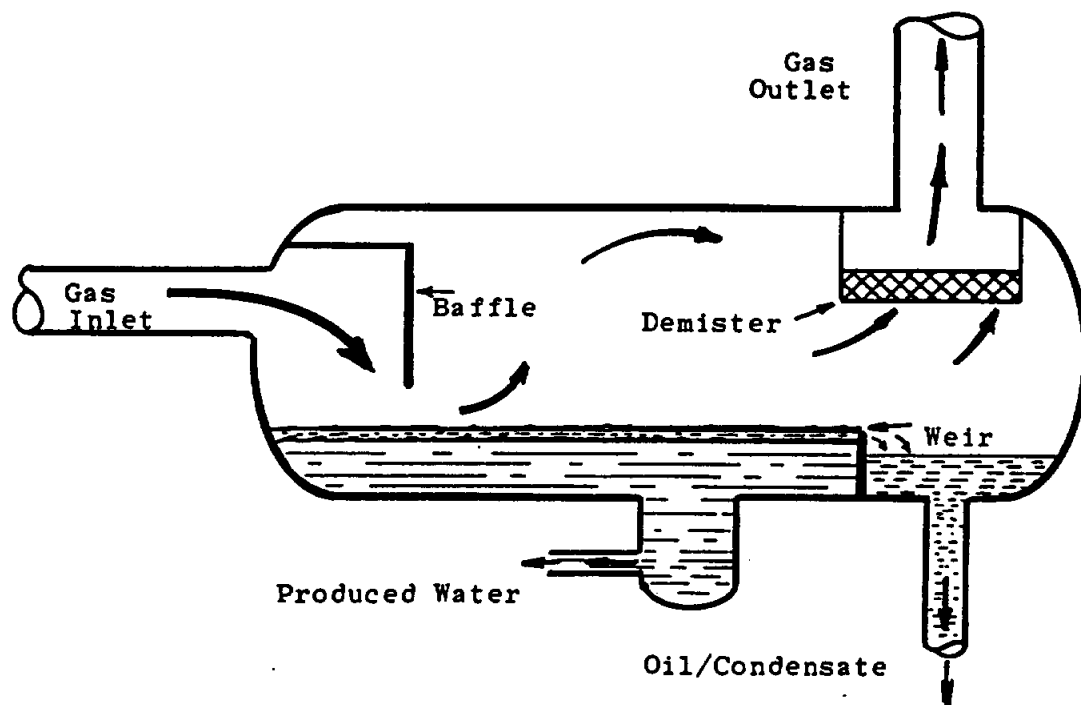
1. Gas/oil/water separators
  - i) Production separator
  - ii) Test separator
  - iii) Condensate separator
  - iv) Flash/degassing/vacuum separators
2. Gas/liquid separators
  - i) Slug catcher
  - ii) Scrubber/suction drum
  - iii) Knock out drum
  - iv) Suction boot
3. Oil/water separators
  - i) Oily water separator
  - ii) Flotation unit
  - iii) Skimmer
  - iv) Coalescer
4. Holding tanks.

### 1. GAS/WATER/OIL (CONDENSATE) SEPARATORS

The production separators lie at the very heart of the oil and gas production processes and are virtually identical to each other in design and to the other separators included in this category.

#### i) a. Production separator-gas process.

The production separator (gas) is primarily concerned with the removal of liquids (water and condensate) from the gas stream and their subsequent separation prior to discharge from the vessel. The process gas entering the separator is forced to undergo a sharp change in direction and the momentum possessed by the entrained liquids ensures that they are thrown out of the gas stream and into the base of the vessel. Given time, the separation of the two liquids will proceed naturally due to the variation in their specific gravities. The liquid levels are monitored by an oil/water interface sensor to ensure that the water is maintained at a level which permits the flotation of oil over a weir located in the end of the vessel.



## PRODUCTION SEPARATOR

### b. Production separator-oil process.

The production separator (oil) is primarily concerned with the separation of gas and water from the crude oil. As the crude oil enters the separator the reduction in pressure facilitates the release of dissolved gases which are removed from the top of the vessel for further processing. The separation of oil from water relies on the variation in specific gravities of the two liquids in a process identical to that employed by the gas process production separator.

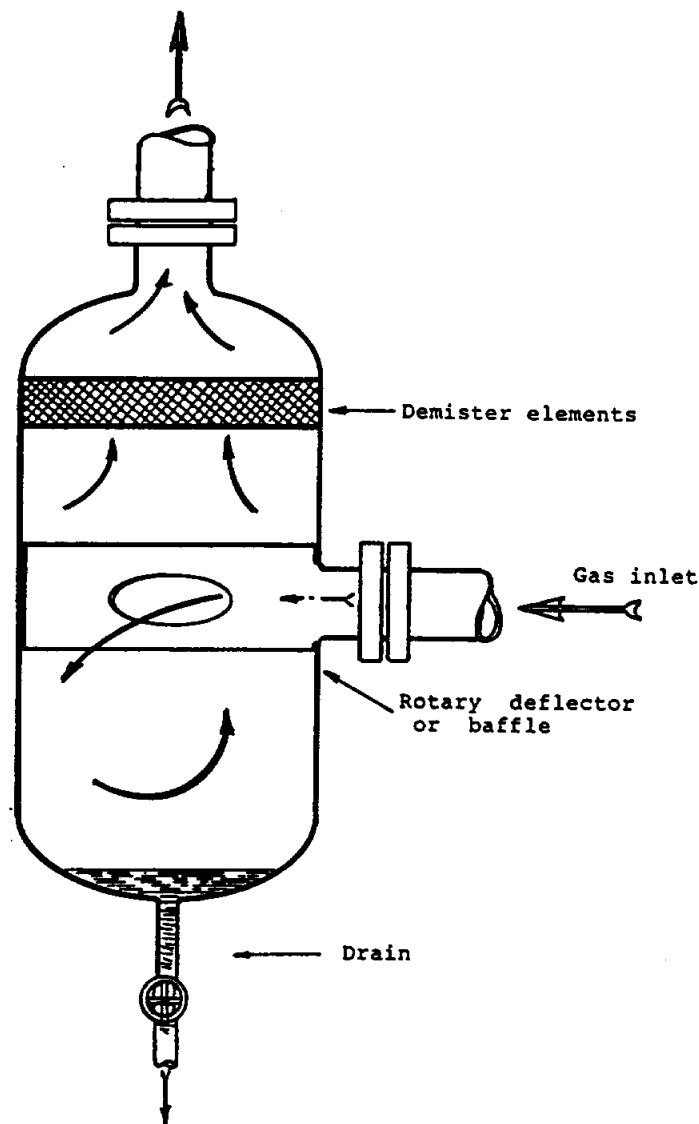
### ii) TEST SEPARATOR

The test separators are identical to the production separators in all but size being designed to process the contents of only one well at a time. A manifold arrangement provides the means by which each individual well can be routed into the separator whilst metering devices located in the vessel discharge nozzles permit the measurement of oil/condensate, gas and water. The results obtained provide an indication as to the performance of a particular well and to the condition of the reservoir.

### iii) CONDENSATE SEPARATOR

The condensate separator is identical in operation to the gas process production separator and facilitates the removal of natural gas liquids (NGL) from the process gas stream.





**GAS SCRUBBER OR SUCTION DRUM**

**iv) FLASH/DEGASSING/VACUUM SEPARATORS**

These vessels are all smaller versions of the oil process production separator which operate at, near or below atmospheric pressure..

**2. GAS/LIQUID SEPARATORS**

The vessels in this category are concerned primarily with the removal of liquids from a gas stream and employ a primitive baffle or diffuser to divert the gas and eject the heavy liquid phases. No attempt is made to separate the liquids thus removed, they are simply discharged into the produced water systems or routed for further processing.

i) **SLUG CATCHER**

The slug catcher will be found on the end of subsea pipelines and on gas production installations where the reservoir generates large quantities of water and/or sand. It prevents slugs ( surges ) of water or sand flooding the gas process plant and upsetting the more delicate items of equipment.

ii) **SCRUBBERS/SUCTION DRUMS**

Essentially identical to one another, the scrubber is located after a heat exchanger whilst a suction drum precedes a compressor. They are a more refined version of the slug catcher operating on identical principles but further employing demister pads (metal mesh screens) more suited to the removal of condensed liquid droplets rather than large liquid slugs.

iii) **KNOCK OUT DRUMS (OR POT)**

The K.O. drum is identical to the slug catcher but is employed at the end of vent headers (manifolds ) to remove hydrocarbon liquids that could otherwise damage the vent stack or constitute a hazard if released into the atmosphere.

iv) **SUCTION BOOT**

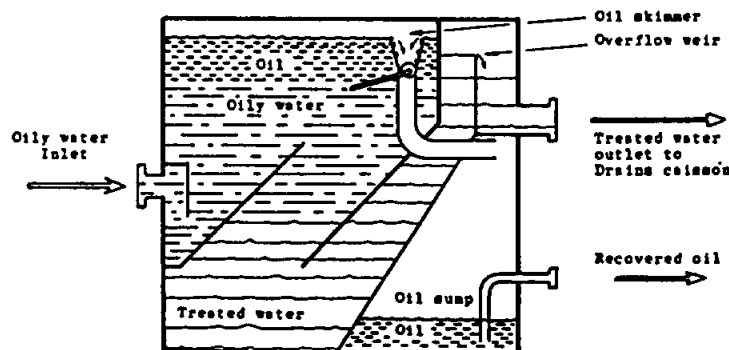
The suction boots are normally associated with gas compressor suction pipelines and can best be explained with the aid of the sketch shown above. The vertical suction pipe is extended below the horizontal section so that moisture deposited during the ascent of the gas into the compressor can be safely removed from the system.

### 3. OIL/WATER SEPARATORS

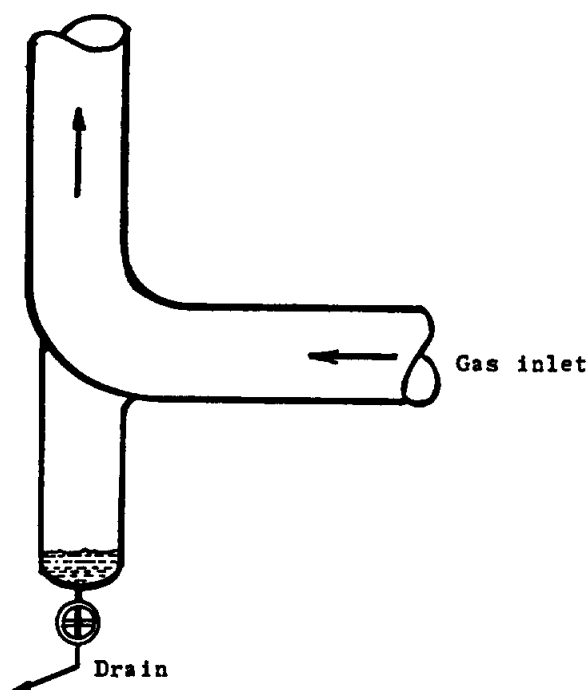
The vessels which fall into this category are used primarily for the separation of oil or condensate from water and with the exception of the coalescer, are associated with the produced water and drains systems. The vessels rely on the variation in the specific gravities of the two liquids to effect separation and again with the exception of the coalescer, they operate at atmospheric, or near atmospheric pressure.

i) **OILY WATER SEPARATOR (OWS)**

The sketch below is self explanatory, the various baffles channel the separated water to the outlet connection whilst oil is "skimmed" from the surface and drained into a holding tank.



**OILY WATER SEPARATOR (OWS)**



**SUCTION BOOT**

**ii) FLOTATION UNIT**

The operation of the flotation unit is basically identical to that of the OWS.

**iii) SKIMMER**

The flotation unit and skimmer are essentially variations on the same theme. Some skimmers employ a separation weir whilst others are devoid of all internal equipment and rely on a level switch and an oil/water interface meter to effect separation of the two liquids via the control of drainage valves.

**iv) COALESCER**

Condensate received by the coalescer should be relatively water free. The coalescer performs a final "polishing" operation on the condensate prior to its injection into the subsea pipeline. The vessel operates at process pressure and contains metal screens, corrugated steel rolls or anthracite which are all designed to increase the surface area of the vessel and encourage entrained moisture to "coalesce" and separate from the condensate.

## **4. HOLDING TANKS**

A number of holding tanks are incorporated in the design of the various piping systems and the bad oil, drains sump and drains drums are typical examples of the type. Generally speaking the tanks consist of atmospheric pressure vessels devoid of all internal equipment which are used as temporary storage for oil, water and condensate products prior to subsequent processing. The vessel contents are maintained between pre-determined limits by a transfer pump activated by a level sensing device.

### **Part 3. PIPING AND PRESSURE VESSEL DESIGN**

The roots of the modern oil industry lie in the USA where the birth of the mass produced automobile gave rise to a phenomenal demand for gasoline. The ensuing black gold rush necessitated the development of equipment and working practices that reflected the specific requirements of the oil and gas industry. It is therefore not surprising that the standards, codes and recommended working practices produced by the Americans have been adopted by, or used as the basis of new standards by all countries now involved in the oil and gas industry.

There are a number of national standards organisations (NSO) and institutions that have developed specifications and codes of practice relating to the design, construction, installation and testing of offshore pipeline systems and pressure vessels and these may be listed as:-

- |    |      |   |
|----|------|---|
| 1. | BS   | British Standards Institute                       |
| 2. | IP   | Institute of Petroleum (UK)                       |
| 3. | API  | American Petroleum Institute                      |
| 4. | AISI | American Iron and Steel Institute                 |
| 5. | ANSI | American National Standards Institute             |
| 6. | ASME | American Society of Mechanical Engineers          |
| 7. | NACE | National Association of Corrosion Engineers (USA) |
| 8. | ASTM | American Society for Testing and Materials        |
| 9. | MSS  | Manufacturers Standardization Society (USA)       |

Specifications may be loosely divided into three categories.

#### **1. PIPING SYSTEMS - INSTALLATION AND LAYOUTS**

The American Petroleum Institute (API) produce a number of "recommended practices" (RP), which provide guidance in the design and layout of offshore piping systems. They are informative, easy to read and are used as the basis for industry standards worldwide. The more frequently used RP's are:-

- i) **API RP 2G**, Recommended Practice for Production Facilities on Offshore Structures.  
(now discontinued)
- ii) **API RP 14E**, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems.
- iii) **API RP 1111**, Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines.
- iv) **API RP 14C**, Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms.

- v) **API RP 520**, Recommended Practice for the Design and Installation of Pressure Relieving Systems in Refineries - Parts I and II.
- vi) **API RP 521**, Guide for Pressure and Depressuring Systems.

## 2. PIPING SYSTEMS - DESIGN

Once again we find that American standards predominate, regardless of the geographic location of the rigs.

- i) **ANSI/ASME B31.3**. Chemical plant and petroleum refinery piping.
- ii) **NACE MR-01-75**. Sulphide stress cracking resistant material for oilfield equipment.
- iii) **BS 4515**. Welding of steel pipelines on land and offshore.  
**BS 8010**. Code of practise for pipelines.
- iv) **BS 3351** (withdrawn). Specification for piping systems for petroleum refineries and petrochemical plants.

It would be true to say that virtually all hydrocarbon process pipework is manufactured in accordance with the requirements of ANSI/ASME B31.3. Reference to BS 3351 may occur on some older installations but this standard has since been withdrawn.

When fabricating pipework for the conveyance of sour gas or oil then the requirements of the NACE MR-01-75 must be complied with in addition to ANSI/ASME B31.3. Sour products contain sulphur compounds, notably hydrogen sulphide ( $H_2S$ ) which is a highly toxic, corrosive gas with the odour of rotten eggs. The UK fields produce predominantly "sweet" gas but where hydrogen sulphide does occur, the requirements of NACE must be strictly adhered to, particularly in the selection of materials and in the approval of welding procedures.

Whilst it is permissible to use American Codes such as ANSI/ASME for process pipework on UK registered installations, the subsea pipelines come under the jurisdiction of the Pipeline Department of the Health and Safety Executive (HSE), and must be manufactured to the requirements specified in B.S.4515.

## 3. PRESSURE VESSELS - DESIGN

Today, almost all new vessels destined for use on UK registered installations are manufactured in accordance with the requirements specified in BS 5500 (small air receivers may be constructed to BS 5169). However, BS 5500 was not introduced until 1976 and consequently up to about 1980, the majority of pressure vessels were manufactured in accordance with the ASME Code.

### 3.1 ASME BOILER AND PRESSURE VESSEL CODE

The beauty of the ASME Code is that it exists as a self contained reference library which covers not only the design and manufacture of pressure vessels (Section IX), but also the specifications for non-destructive examination (NDE) (Section V), and approval of welding procedures and welders (Section IX).

The ASME Code consists of 11 volumes or sections which cover all aspects of fired and unfired pressure vessel construction. They are:-

- i) Power Boilers.
- ii) Material Specifications
  - Part A - Ferrous Materials
  - Part B - Nonferrous Materials
  - Part C - Welding Rods, Electrodes, and Filler Metals
  - Part D - Properties
- iii) Subsection NCA - General Requirements for Division 1 and Division 2
  - Division 1
    - Subsection NB - Class 1 Components
    - Subsection NC - Class 2 Components
    - Subsection ND - Class 3 Components
    - Subsection NE - Class MC Components
    - Subsection NF - Component Supports
    - Subsection NG - Core Support Structures
    - Appendices
  - Division 2 - Code for Concrete Reactor Vessels and Containments
- iv) Heating Boilers
- v) Non-destructive Examination
- vi) Recommended Rules for Care and Operation of Heating Boilers
- vii) Recommended Guidelines for the Care of Power Boilers
- viii) Division 1 - Pressure Vessels  
Division 2 - Alternative Rules
- ix) Welding and Brazing Qualifications
- x) Fibre-Reinforced Plastic Pressure Vessels
- xi) Rules for Inservice Inspection of Nuclear Power Plant Components

The Sections covering NDE and welding qualification tests are referred to by numerous piping specifications, including ASME/ANSI B31.3.

### **3.2 BS 5500 UNFIRED FUSION WELDED PRESSURE VESSELS**

The BS 5500 is not as self contained as the ASME Code and must be used in conjunction with a number of British Standards to obtain information pertaining to NDE and welding requirements. The main supporting documents are:-

## PIPING SYSTEMS AND PROCESS PRESSURE VESSELS

- i) **BS 4870** Specification for approval testing of welding procedures.
- ii) **BS 4871** Specification for approval testing of welders working to approved welding procedures.
- iii) **BS 2910** Radiographic examination of fusion welded circumferential butt joints in steel pipes.
- iv) **BS 2600** Radiographic examination of fusion welded butt joints in steel.
- v) **BS 3923** Ultrasonic examination of welds.
- vi) **BS 4416** Penetrant testing of welded or brazed joints in metals.
- vii) **BS 6072** Methods for magnetic particle flaw detection.

Note 1. Whilst BS 4870 and 4871 were superseded in 1992, they were in use for over 20 years and will be encountered repeatedly, particularly as the new standards do not invalidate previous approvals. The new standards are:-

**B.S. EN 287** Approval testing of welders for fusion welding.

**B.S. EN 288** Specification and approval of welding procedures for metallic materials.

## Part 4 PIPING SYSTEMS - CONSTRUCTION

Offshore piping systems must be designed and constructed in accordance with a recognized fabrication specification and ANSI/ASME B31.3 (Chemical Plant and Petroleum Refinery Piping) tends to be used as the basis for the vast majority of process and utility piping systems. The specification stipulates parameters which cover the design, selection of materials, construction techniques, non-destructive examination (NDT) and hydrostatic pressure test requirements.

A piping system must be designed to comply with a specific pressure rating or class in accordance with the following table.

CLASS	WORKING PRESSURE		TEST PRESSURE	
	psig	bar	psig	bar
150	285	20	450	30
300	740	51	1125	78
400	990	68	1500	104
600	1480	102	2225	154
900	2220	152	3350	230
1500	3705	255	5575	383
2500	6170	423	9275	639

(Figures quoted are for maximum non shock working pressures at temperatures between -20F/-29C and 250F/121C.)

A piping system contains a selection of components categorised as either pipe, fittings or valves and these components are further categorised by the method of assembly. The various methods of assembly will be dealt with first.

### i) THREADED

Threaded fittings are used extensively for low pressure utility systems and may be used for hydrocarbon service up to 2 inch (50mm) nominal bore (N.B.).

### ii) SOCKET WELDED

Socket welded components employ a fillet weld as the means of attachment and they may be used for utility pipework up to 3 inch (75mm) N.B. and for hydrocarbon service up to 2 inch ( 50mm ) N.B.

### iii) BUTT WELDED

Butt weld fittings are preferred for critical service applications such as high pressure hydrocarbon process systems. A butt weld offers maximum security and permits the application of more searching NDT techniques.

The various component parts of a piping system will now be discussed.



## 1. PIPE

Prior to the selection of a pipe material specification the service conditions of the system must first be established. The service conditions primarily relate to operating pressure, temperature and the ability to resist corrosion. Approximately 95% of offshore piping systems are manufactured from Grade B pipe which complies with ASTM A106, or API 5L specifications. These and other relevant specifications will now be discussed.

### i) ASTM A106 - Specification for Seamless Carbon Steel Pipe for High Temperature Service.

The vast majority of utility and process piping systems are fabricated from pipe complying with this specification. Suitable for applications ranging in temperature from  $-29^{\circ}\text{C}$  to  $343^{\circ}\text{C}$  ( $-20^{\circ}\text{F}$  to  $650^{\circ}\text{F}$ ) it is also used for systems operating within the normal operating temperature range of  $-29^{\circ}\text{C}$  to  $204^{\circ}\text{C}$  ( $-20^{\circ}\text{F}$  to  $400^{\circ}\text{F}$ ) and is available in sizes ranging from 2 inch (50mm) N.B. to 24 inch (609mm) N.B.

### ii) API SPEC 5L - Specification for Line Pipe.

Line pipe to specification 5L Grade B is generally used for the larger diameter pipeline systems operating within the ambient temperature range and is available in sizes up to 80 inch (2,032mm) outside diameter. The specification includes a range of high strength steel pipes such as API Spec 5L Grade X 52, a material that will be frequently encountered in subsea pipeline service. Due to the higher carbon content of these steels they may require specialised welding procedures and close supervision during production welding if sound welds are to be achieved.

The numerical designation indicates the yield strength of the pipe e.g. X 52 = 52,000 psi.

### iii) ASTM A333 - Specification for Seamless and Welded Steel Pipe for Low Temperature Service.

There are a limited number of applications which require a pipe suitable for low temperature service but A333 is used extensively for high pressure vent systems due to the low temperatures generated by the gas as it expands during venting. The temperature range of the basic grade pipe is  $-46^{\circ}\text{C}$  to  $343^{\circ}\text{C}$  ( $-50^{\circ}\text{F}$  to  $650^{\circ}\text{F}$ ) but grades are available for temperatures as low as  $-320^{\circ}\text{F}$  /  $-196^{\circ}\text{C}$ .

### iv) ASTM A312 - Specification for Seamless and Welded Austenitic Stainless Steel Pipe.

Stainless steels are used where resistance to corrosion or clinical cleanliness are required and typical service applications are chemical injection and helifuel distribution systems where grade 316L will be encountered frequently.

### v) ASTM A790 - Specification for Seamless and Welded Ferritic/Austenitic Stainless Steel Tube for General Service.

The A790 range of stainless steels are normally referred to as Duplex having a significantly higher chromium content than the A322 stainless steels. However, the addition of Nitrogen and Molybdenum greatly enhance the mechanical properties of the steel virtually doubling the yield strength and increasing the resistance to corrosion, and stress corrosion cracking. The price of the material increases in a similarly dramatic manner.

The combination of high strength and corrosion resistance has made the Duplex steels a popular choice for corrosive hydrocarbon service and they are being used increasingly for subsea pipelines and wellhead manifolds, particularly where sour reservoir products are encountered.

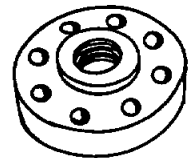
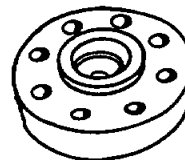
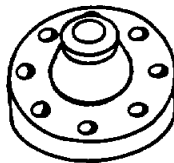
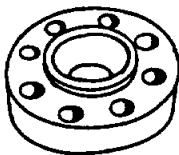
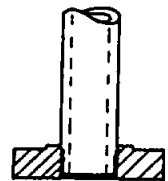
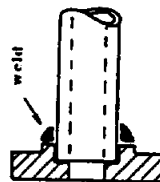
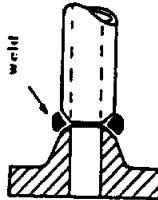
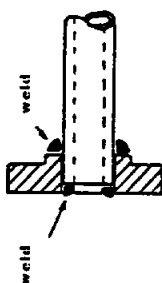
vi) CUNIFER

Cunifer is a 90/10 copper nickel alloy which is used extensively for the construction of fire mains and general service sea water systems due to its ability to resist the corrosive effect of sea water.

Having established the most suitable material for a particular piping system and the diameter required to produce a satisfactory flow rate, the wall thickness or pipe schedule required to withstand the design pressure and temperature can be determined from tables reproduced within the relevant specification.

It is recommended that a minimum schedule 80 pipe thickness be employed for hydrocarbon process systems of 3 inch (75mm) N.B. or less in order to combat the effects of vibration and corrosion. The wall thickness quoted in the piping specification includes a corrosion allowance of 0.05 inch (0.2mm).

All pipe should be clearly marked with the material specification and grade and supported by suitable documentation.



SLIP ON

WELD NECK

SOCKET WELD

SCREWED

FLANGE TYPES

## 2. FITTINGS

The term "fittings" includes items such as flanges, elbows, bends, reducers and branches and should be manufactured in accordance with one of the following specifications.

### i) FLANGES

#### a) ANSI B16.5 - Steel Pipe Flanges and Flanged Fittings.

There are 7 flange ratings in the AISI/ASA series and they are used for virtually all utility and process services. These flanges are supplied with a raised face (RF) sealing area up to and including AISI 400 rating whilst the higher pressure flanges are machined to accommodate ring groove (RJ) sealing joints.

The 7 available ratings are:-

AISI 150, 300, 400, 600, 900, 1500, 2500.

The numerical part of the designation indicates the maximum non-shock loading pressure rating in pounds per square inch at a temperature of 850°F/454°C.

The temperature range that most offshore piping systems are designed for is -29°C to 37°C (-20°F to 100°F) and within these temperatures the working pressures can be increased to the corresponding values shown in the table at the beginning of the chapter.

A rule of thumb method of calculating the ambient working pressure of an AISI flange or valve is to multiply the designated rating by 2.4 e.g. AISI 300 x 2.4 = 720 psig.

Similarly the maximum test pressure can be approximated by multiplying by 3.5 e.g. AISI 300 x 3.5 = 1050 psig.

N.B. These rules do not apply to Class 150 components.

#### b) API Spec 6A - Wellhead Equipment

The API range of flanges are used for wellhead service and are supplied in four pressure ratings, the numerical designation indicating the maximum working pressure within the operating temperature range of -29°C to 121°C (-20°F to 250°F). The flanges are all of the ring groove type and are available in the following pressure ratings :-

API 2000, 3000, 5000, 10000.

#### c) MSS SP-44 - Steel Pipe Line Flanges

The Manufacturers Standardization Society (MSS) developed the Standard Practice (SP) 44 due to the demand for flanges in sizes larger than the 24 inch diameters covered by ANSI B16.5. The Standard contains a selection of flanges varying in size from 12 inches to 38 inches and in pressure ratings corresponding to the customary ANSI classes, namely 150, 300, 400, 600 and 900.

#### d) Gaskets - Spiral wound gaskets are used as a sealing medium on AISI raised face (RF) flanges up to and including Class 400.

The higher pressure rated flanges and all the API flanges employ ring joint seals. Soft iron rings are used for 600 and 900 class flanges and low carbon steel rings for all other ratings.

**ii) FITTINGS (other than flanges)**

The remaining fittings are covered by the following specifications which are self explanatory.

- a) ANSI. B16.9 - Wrought Steel Butt Welded Fittings.
- b) ANSI. B16.11 -Forged Steel Fittings, Socket Welded and Threaded.

Fittings intended for use with Grade B pipe ( A106 or 5L ) should be manufactured from materials which comply with:-

- i) ASTM A234 - Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and Elevated Temperatures.
- or,
- ii) ASTM A105 - Specification for Forgings, Carbon Steel, for Piping Components.

**3. VALVES**

The choice of valve for a particular piping application will be dictated by the service conditions of the piping system and the mode of operation required. A number of valve types are available and may be briefly described as follows:-

**i) BALL VALVE**

The ball valve is normally associated with hydrocarbon service as it provides an efficient on/off operation. The valve is ideally suited to automation because of the short distance that the actuator has to travel to effect full operation.

**ii) GATE VALVE**

Like the ball valve, the gate valve is used extensively in hydrocarbon service applications and in particular for christmas tree valves. Whilst the valve seats are prone to damage they are relatively cheap and easy to replace.

**iii) PLUG VALVE**

The plug valves have a similar action to a ball valve and are widely used for hydrocarbon systems of less than 3 inch (75mm) NB. They are particularly suitable for drain lines because of their quick and efficient sealing action.

**iv) CHOKE VALVE**

Manual, and automatic chokes are used extensively to regulate the flow of hydrocarbons in both process and drilling applications. On production installations automatic chokes are frequently fitted to the christmas tree wing valves in order to reduce well pressures to that required by the process plant.

**v) BUTTERFLY VALVE**

Butterfly valves can be difficult to make leak tight but the inclusion of a neoprene sealing face greatly enhances the sealing effectiveness. They are used predominately as isolation valves on fire mains.

## PIPING SYSTEMS AND PROCESS PRESSURE VESSELS

### vi) DIAPHRAGM VALVE

The diaphragm valves tend to be restricted to low pressure sea water service where they provide an enduring efficient seal.

### vii) CHECK VALVE

Check valves may also be described as reflux, non-return, back pressure, retaining and clack valves. The purpose of a check valve is to permit flow in one direction and to prevent it in the reverse direction and they are used extensively in hydrocarbon and utility piping systems.

One of the more recent regulations that valves intended for hydrocarbon process or firemain service must comply with is a fire test. The valves must meet the fire tests requirements of API RF 6FA or B.S. 6755 if used for hydrocarbon service.

Other relevant specification pertaining to valves are:-

#### a) Stud bolts

ASTM A193 - Specification for Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature Service.

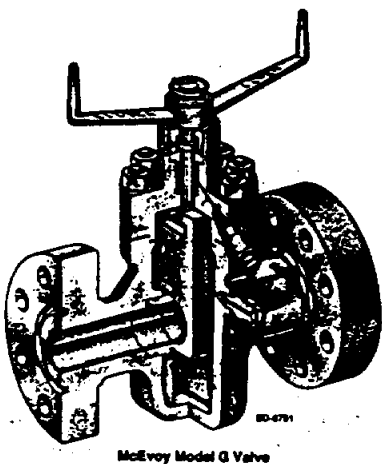
ASTM A320- Specification for Alloy Steel Bolting Materials for Low-Temperature Service.

#### b) Nuts

ASTM A194 - Specification for Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service.

Bolts and nuts should be protected against corrosion by cadmium plating, hot dip galvanizing or resin coatings.

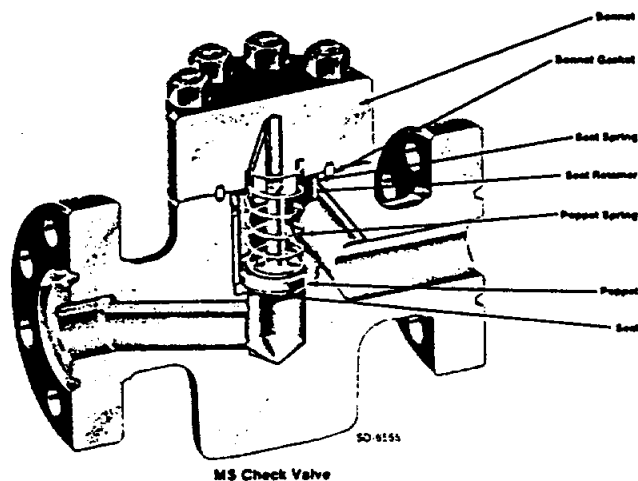
The acid test of the finally completed piping system is the hydrostatic pressure test. This should be carried out at a pressure of  $1.5 \times$  design pressure and is intended to highlight any weaknesses in the structural integrity of the constituent components of the piping system. It should not be confused with a leak test which may be carried out at  $1.1 \times$  design pressure the object of which is to simply ensure there are no leaks from valves, gaskets, plugs and other temporary fittings.



**GATE VALVE**



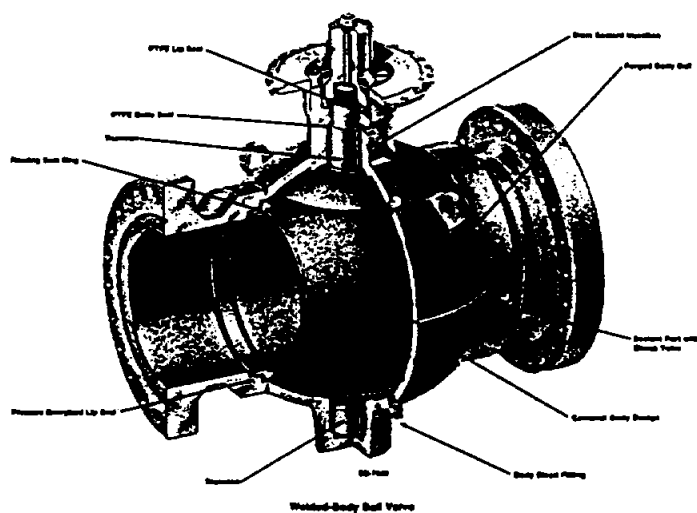
**BALL VALVE**



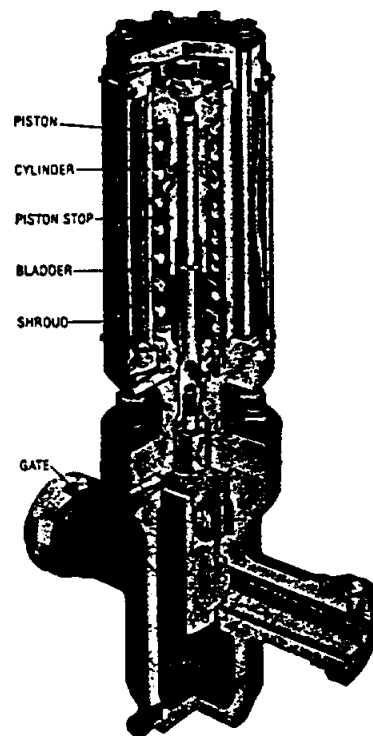
CHECK VALVE



CHOKE



WELDED-BODY BALL VALVE



W-K-M Self-T-Seal subsea valve with D-2C hydraulic actuator with integral backdoor to balance seawater head.

SUBSEA GATE VALVE AND ACTUATOR

(Reproduced with permission of Cooper Oil Tools, Houston Texas)

# **Chapter Five**

## **PRODUCTION**

### **PART 1 - GAS PRODUCTION**

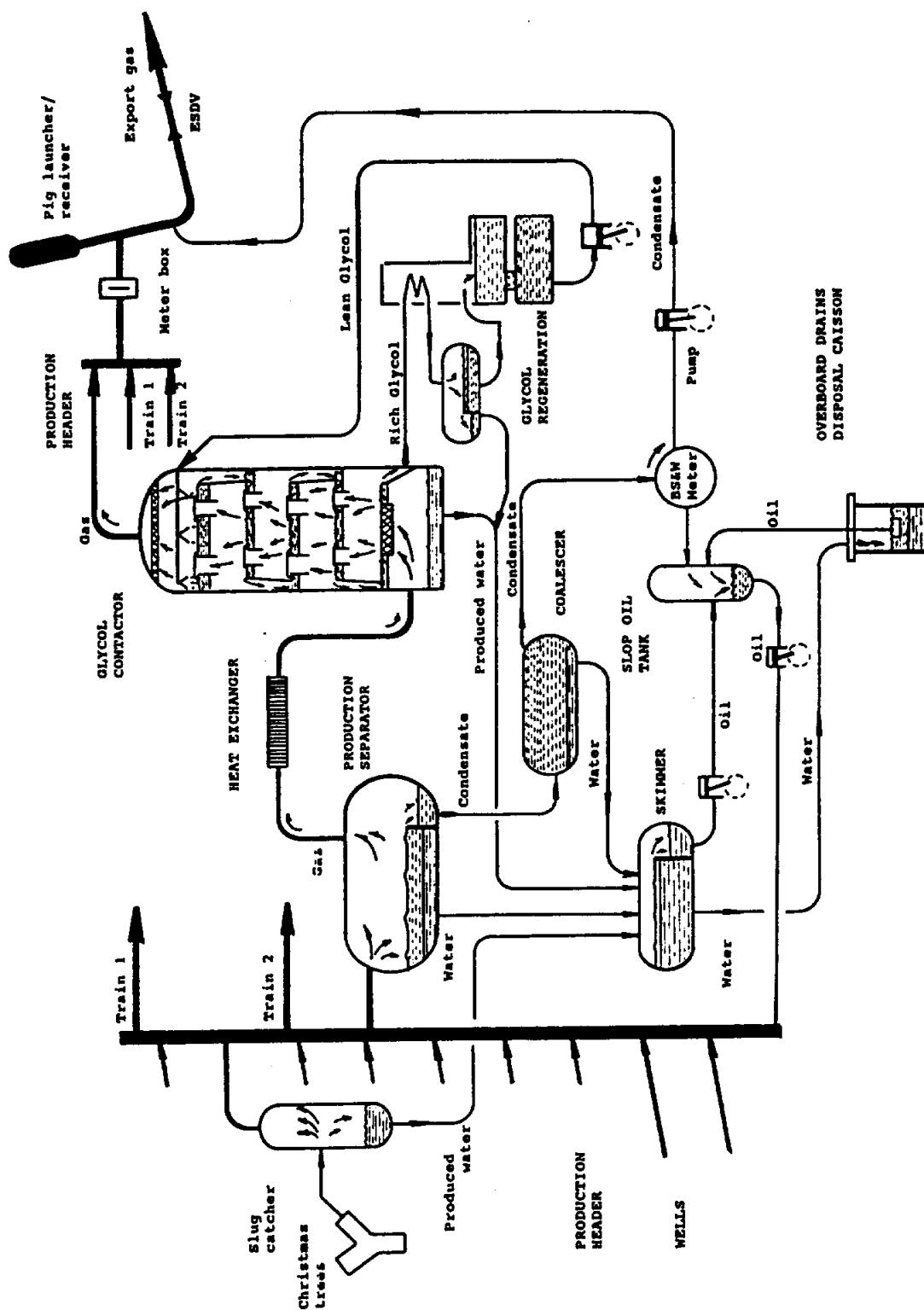
- 1 THE GAS PROCESS
- 2 THE LIQUID PROCESS
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### **PART 2 - OIL PRODUCTION**

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GAS PRODUCTION PROCESS



## OIL AND GAS PRODUCTION

The main function of the process plant on an offshore installation is to separate hydrocarbon products into liquid and gaseous phases and to remove any impurities that could inhibit transportation, such as water. The refinement process is loosely described as "production".

Before embarking on the description of the oil and gas production processes, the definition of what constitutes an oil field and a gas field must be clearly understood.

Basically speaking the underground rock formations which create conditions conducive towards the formation of an oil field are somewhat different to those which constitute a gas field and for this reason offshore installations are generally categorised as either oil or gas producing. In the U.K. sector of the North Sea, almost all the gas fields are located in the southern sector where there is absolutely no oil. In the northern sector the fields are predominately oil producing but the oil is also associated with gas and water. Consequently, an oil production installation usually features a gas process plant in addition to the oil processing facility.

The production processes rely on very basic principles of fluid flow and thermo-dynamics and the reader would be justified in expecting to find virtually a standard design of offshore installation. In practice, this is certainly not the case for whilst to a certain extent the process equipment must be tailored to suit individual reservoir conditions, it is often Company policy which exerts the greatest influence on platform design, an aspect of offshore engineering which can be particularly frustrating. However, whilst equipment layout may vary from installation to installation, the general principles of operation remain the same.

In order to simplify the explanation of the oil and gas production processes they have been dealt with separately.

## **Part 1. GAS PRODUCTION**

The basic function of the process equipment on a gas producing offshore installation is to remove water prior to the transportation of the gas to the onshore reception facility.

### **1. THE GAS PROCESS**

The sketch on page 104 has been prepared to assist in the explanation of the gas production process.

#### **i) WELLHEADS**

The gas process commences at the christmas tree. This is the main isolation valve assembly through which wet gas at full reservoir pressure 2000-3000 psig(140-200 bar) must pass before entering the production flowline. From the flowline the gas enters a slug catcher where the first phase of liquid removal takes place.

#### **ii) SLUG CATCHER**

The slug catcher design facilitates the removal of large slugs of water and sand prior to the gas entering the production header.

In common with most gas process equipment, the slug catcher relies on very basic principles of fluid dynamics for its operation. The incoming gas is forced to make a sharp change of direction within the vessel and in so doing, the heavy liquid phases are thrown out into the base of the vessel. The liquids are disposed of via the produced water system.

#### **iii) METER RUN AND TEST SEPARATOR**

Having removed any large slugs of liquid or sand that could prove injurious to subsequent items of process equipment the gas may flow through a metering orifice box prior to entry into the production header. Individual metering of each well permits output to be regulated and provides an indication as to the performance of the well. When more specific information is required the well can be routed through a test separator which can measure the exact quantities of gas, water and condensate produced. Regular condition monitoring of the reservoir provides an early indication of any problems likely to effect gas production and permits corrective action to be taken.

#### **iv) PRODUCTION HEADER**

The production header is essentially a manifold which receives the gas from all the slug catchers (maybe 12) and redistributes it into a number of process trains (maybe 3). For reasons of clarity, only one process train is shown in the diagram.

Some installations do not require slug catchers so the production header receives gas direct from the christmas tree flowlines.

The next step in the liquid removal process takes place in the production separator. However, before the gas enters the production header it must be reduced in pressure to 1,440 psig (98 bar) due to the impracticality of constructing plant and equipment capable of operating at the full reservoir pressure.

Pressure reduction and the regulation of gas flow is effected by a control valve or choke which is automatic in operation. This valve is normally fitted between the slug catcher and production header but in the absence of slug catchers it will be installed on the christmas tree outlet or wing valve.

### v) PRODUCTION SEPARATOR

The production separator facilitates gas and liquid separation in a similar fashion to the slug catcher. However, the liquids thrown out as the gas changes direction settle and separate in the base of the vessel. The water enters the produced water system whilst any condensate (condensed gas liquids) present is discharged into the coalescer.

The gas continues its journey by entering a heat exchanger.

### vi) HEAT EXCHANGER

The purpose of the heat exchanger is to produce gas at a temperature at which the water absorption process within the glycol contactor will be at its most efficient. The type of heat exchanger used will depend on reservoir conditions.

Some reservoirs produce gas at temperatures as high as 60 deg.C/140 deg.F and under these conditions the gas will require cooling before it enters the contactor. This is normally carried out within a thermostatically controlled fan assisted tube type cooler. Cooling the gas assists in the removal of liquids which condense out as the temperature falls.

Once the gas is at the correct temperature it can be passed into the glycol contactor for final drying.

### vii) GLYCOL CONTACTOR (OR ABSORPTION TOWER)

This vessel may function as a combined scrubber and contactor, or the scrubber may exist as a separate vessel through which the gas passes prior to entering the contactor.

At this stage in the process the gas should be relatively dry. The scrubber will entrain any remaining water droplets within a series of fine metal mesh screens before the gas enters the contactor for the final mopping up operation.

The contactor consists of a vertical pressure vessel fitted with a number of horizontal trays over which triethylene glycol (TEG) cascades. As the gas flows upwards through the vessel it "contacts" the TEG which acts like liquid blotting paper absorbing any remaining moisture. The gas then passes through a mist extractor designed to remove any entrained glycol before entering the discharge header. The TEG leaves the base of the vessel for circulation through the glycol regeneration plant. (The dehydration process is described in greater detail under "oil production")

### viii) DISCHARGE HEADER

The discharge header is essentially a manifold which receives gas from the various process trains and redirects it into the export line.

**ix) EXPORT LINE**

The export line usually contains a sphere launcher/receiver, a metering box, a condensate re-injection point and an emergency shut down valve (ESDV).

- (a) **Sphere (or pig) launcher/receiver** - over a period of time, liquids, scale and debris will accumulate in the horizontal section of the sub sea pipe line and eventually gas flow will be affected. To counter this problem large poly-propylene spheres or pigs are periodically launched under gas pressure to sweep the line. The operation is known as pigging the line and the debris will be pushed ahead of the pig into a slug catcher at the receiving installation or the reception facility on the beach.

Modern technology has spawned a new addition to the pig family, the "intelligent pig". These sophisticated animals contain a magnetic eddy current measuring device energised by an intrinsically safe power source and are employed to carry out an ultrasonic inspection of the subsea pipeline. The pig is propelled by gas (or oil) pressure and can quickly and efficiently detect any abnormalities in the condition of the pipeline.

- (b) **Condensate re-injection point** - condensate is pumped into the export gas for delivery to the beach where it will again be separated for sale as a separate commodity to the gas.
- (c) **Metering box** - gas leaving the installation enters a subsea pipe line which is invariably shared with other installations in the field. A metering box enables gas production to be calculated to ensure that an installation is credited with its due rewards.
- (d) **E.S.D.V.** - the emergency shut down valve consists of a fail safe fire proof valve designed to isolate the platform from the subsea distribution system. This ensures that should an accident occur, the installation will not be fed with gas from other rigs. These valves were installed because this very situation arose on the Piper Alpha installation. A serious problem turned into a disaster as gas from other rigs fuelled Piper's fires.

To complete the chapter on gas processing a brief explanation of gas compression is required.

**x) GAS COMPRESSION**

Reservoir depletion eventually necessitates the installation of compressors to assist in the extraction of the gas (down to below 50 psig/3 bar) and to ensure that the gas is delivered to the national grid at a pressure of at least 1000 psig (70 bar).

Frequently one platform in the field will be provided with a compression facility and it will receive the gas from various satellite installations to compress for onward transmission.

Where space permits, a self contained compressor package may be located within the confines of the existing installation. However, the larger developments normally require an additional compression jacket to accommodate the compressor trains and associated process equipment. Compressor size and type will vary depending on field requirements but the larger installations tend to use rotating compressors powered by marinised aero engines manufactured by companies such as Rolls Royce. The gas engines run on fuel gas produced on the installation.

## 2. THE LIQUID PROCESS

As previously stated, the basic function of the process equipment on a gas producing offshore installation is to remove water prior to the transportation of the gas to the onshore reception facility.

The bulk of the water is deposited in the Production Separators in a relatively straightforward operation but the process is complicated by the fact that the water is often accompanied by condensate, a valuable hydrocarbon by product. In the Production Separators the condensate and water separate by gravitation prior to their discharge through separate outlets. The condensate is directed to the coalescer where any remaining water is removed whilst the water enters the produced water system where any remaining oil is removed.

The systems employed for the recovery of the condensate and the purification of the water will now be discussed, after first explaining why it is imperative that the water is removed.

### i) PREVENTION OF HYDRATES

Under certain conditions of temperature and pressure water particles separate from the gas stream and freeze, trapping hydrocarbon molecules to form a solid ice like substance known as a hydrate. Restrictions such as valve chests, orifice plates, pipeline reducers and bends exacerbate the problem as they create a throttling effect which further cools the gas and accelerates hydrate formation. If left unchecked the hydrates will eventually form a blockage at these restrictions and in extreme cases complete sections of the subsea pipeline have been known to freeze.

Methanol and monoethylene glycol (MEG) are used extensively by the offshore industry to depress the dew point of the gas stream and thus reduce the possibility of hydrate formation. They may be injected into the process plant, subsea pipeline and the wells (methanol only) during periods of peak production when conditions of temperature and pressure approach values known to produce hydrates. The choice of inhibitor is largely dictated by individual company preference.

Should a hydrate blockage occur it can be left to thaw naturally or melted by injecting methanol. Prior to thaw the gas pressures either side of the blockage must be equalised if an explosive collapse of the hydrate is to be avoided. Propelled by gas pressure a hydrate can cause a tremendous amount of damage smashing valve chests, pipe bends and puncturing pressure vessels.

In time the natural reservoir pressure will decline and remove the conditions associated with hydrate formation. This will permit the removal of certain items of process plant such as the glycol regeneration system.

### ii) PREVENTION OF CORROSION

Due to the colossal costs associated with the installation and replacement of subsea pipelines, every effort must be made to eliminate corrosion. The composition of natural gas produced from the North Sea varies considerably from field to field but consists primarily of methane (60% to 92%) and ethane (3% to 15%) with smaller percentages of propane, butane, pentanes and hexanes. Two of the least desirable constituents which may also be found in the gas are carbon dioxide ( $\text{CO}_2$ ) and hydrogen sulphide ( $\text{H}_2\text{S}$ ), the latter creating a condition referred to as "sour gas".

**Carbon dioxide** can account for up to 25% of the composition of the gas and the carbonic acid produced in the presence of water is the primary cause of "sweet" corrosion in subsea pipelines.

**Hydrogen sulphide** is extremely toxic, highly corrosive and whilst prevalent elsewhere in the world it is fortunately relatively rare in the North Sea. If present, it must be removed if considerable damage to process equipment and personnel are to be avoided. The removal process is referred to as sweetening and is described under oil production.

## **2.1 CONDENSATE SYSTEM**

Condensate is a clear, highly volatile liquid consisting of the heavier hydrocarbon fractions that condense out of the wet gas as it leaves the well.

Liquid processing involves the removal of water from the condensate received from the production separators. The "dry" condensate can then be re-injected into the gas for delivery to the onshore reception facility ("the beach") whilst the water is discharged into the sea, via the produced water system.

### **i) COALESCER**

The coalescer operates at process pressure and its function is to refine the condensate received from the production separator. The condensate passes through fine wafer pads or demisters on to which the water droplets coalesce before falling into the base of the vessel.

The condensate passes through a B.S. & W. (basic sediment and water) detection meter as it leaves the coalescer. If free of water, the condensate is pumped into the gas export line for transportation to the beach. If an unacceptable water content is recorded by the meter, the condensate will be diverted into the slop oil tank for further processing.

### **ii) SLOP OIL TANK**

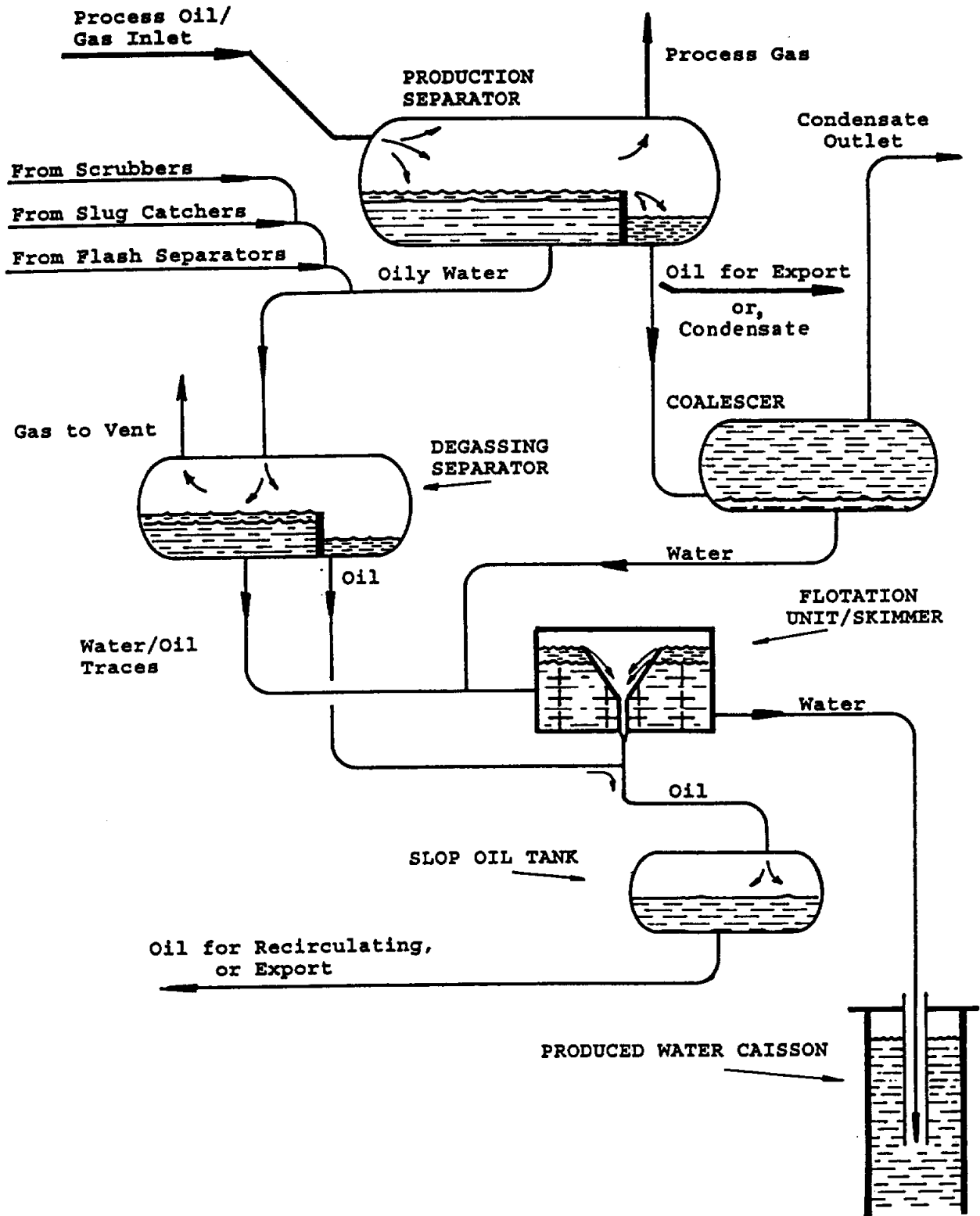
The slop oil tank is simply a holding vessel for water contaminated condensate, known as "slop oil or bad oil". It is fed from the coalescer, skimmer and caisson drains and the contents will eventually be pumped back into the production header for re-circulation through the process equipment.

## **2.2 PRODUCED WATER SYSTEM**

Produced water consists essentially of oil or condensate contaminated water removed from the production separators and other process vessels and the function of the produced water system is to clean the water prior to discharge into the sea.

Generally speaking the production of water increases as the reservoir ages. A basic gas production installation could produce less than 100 tonnes of water a day whilst a large oil production installation may have to cope with the disposal of in excess of 20,000 tonnes of water a day. Whilst the quantities of water may vary considerably the basic equipment and operating principles remain the same for both oil and gas producing installations.

# OIL AND GAS PRODUCTION



## PRODUCED WATER SYSTEM

**i) PRESSURE REDUCTION**

The first operation entails a reduction in the water pressure from that of the oil or gas process to atmospheric, or slightly above atmospheric pressure. This may be achieved by the insertion of orifice plates into the process vessel produced water outlet connections and a degassing drum may also be included in the system.

**ii) DEGASSING DRUM**

The degassing drum facilitates the separation of oil, water and gas. The reduction in pressure permits the release of dissolved gases which are disposed of at the HP vent or flare stack whilst the liquids are separated using an oil/water interface. The oil or condensate is transferred to the slop oil tank whilst the water is directed to a polishing unit for further refinement.

**iii) POLISHING UNIT**

The polishing unit which may also be referred to as a produced water separator, flotation unit or skimmer once again utilises the different specific gravities of oil and water to achieve separation by gravitation. Any remaining oil or condensate is transferred to the slop oil tank whilst the water is discharged into the sea via a dedicated produced water caisson, or the overboard drains disposal water caisson.

**iv) OVERBOARD DRAINS DISPOSAL WATER CAISSON**

The overboard disposal drains caisson provides the final opportunity for any remaining condensate or oil to separate from the water. The oil floats to the top of the caisson where it is returned to the slop oil tank by a transfer pump which is activated automatically by an oil/water interface sensor. An oil content of less than 40 p.p.m. is required before the water can be discharged into the sea.



## **Part 2 OIL PRODUCTION**

It would appear that mother nature has a far greater affinity for her oil than her gas for whilst the exploitation of a gas field proceeds with the ease of deflating a large balloon, the recovery of oil is fraught with problems and resisted at every turn.

Crude oil exists in an underground reservoir accompanied by large quantities of hydrocarbon gas and formation water and it is the gas, and to a lesser extent the water that provide the driving force required to bring the oil to the surface. It is also the gas and water that complicate the process arrangements on board an oil production installation for whilst oil may be difficult to entice from the ground the subsequent processing required prior to export is minimal. The same cannot be said for the refinement of the associated gas and it becomes apparent why in the formative years of the oil industry the gas was simply burnt off at the flare stack. Today, energy conservation policies and the realisation of the value of the gas in terms of both operational and financial benefits have tended to reduce the routine flaring of gas, at least in Europe.

If an equipment plan of an offshore installation is studied a complex picture emerges involving a number of process systems intermingled with one another. However it should be remembered that the basic object of the exercise is simply to separate oil, gas and water and to refine them to an acceptable level of purity prior to their discharge from the installation. These separate processes will now be discussed together with the enhanced oil recovery equipment a most important feature of oil production designed to loosen mother natures grip on her oily treasures.

### **1. THE OIL PROCESS**

The refinement of crude oil to a quality suitable for transportation by subsea pipeline or oil tanker is a remarkably simple operation consisting primarily of the removal of associated gas and formation water within a series of production separators.

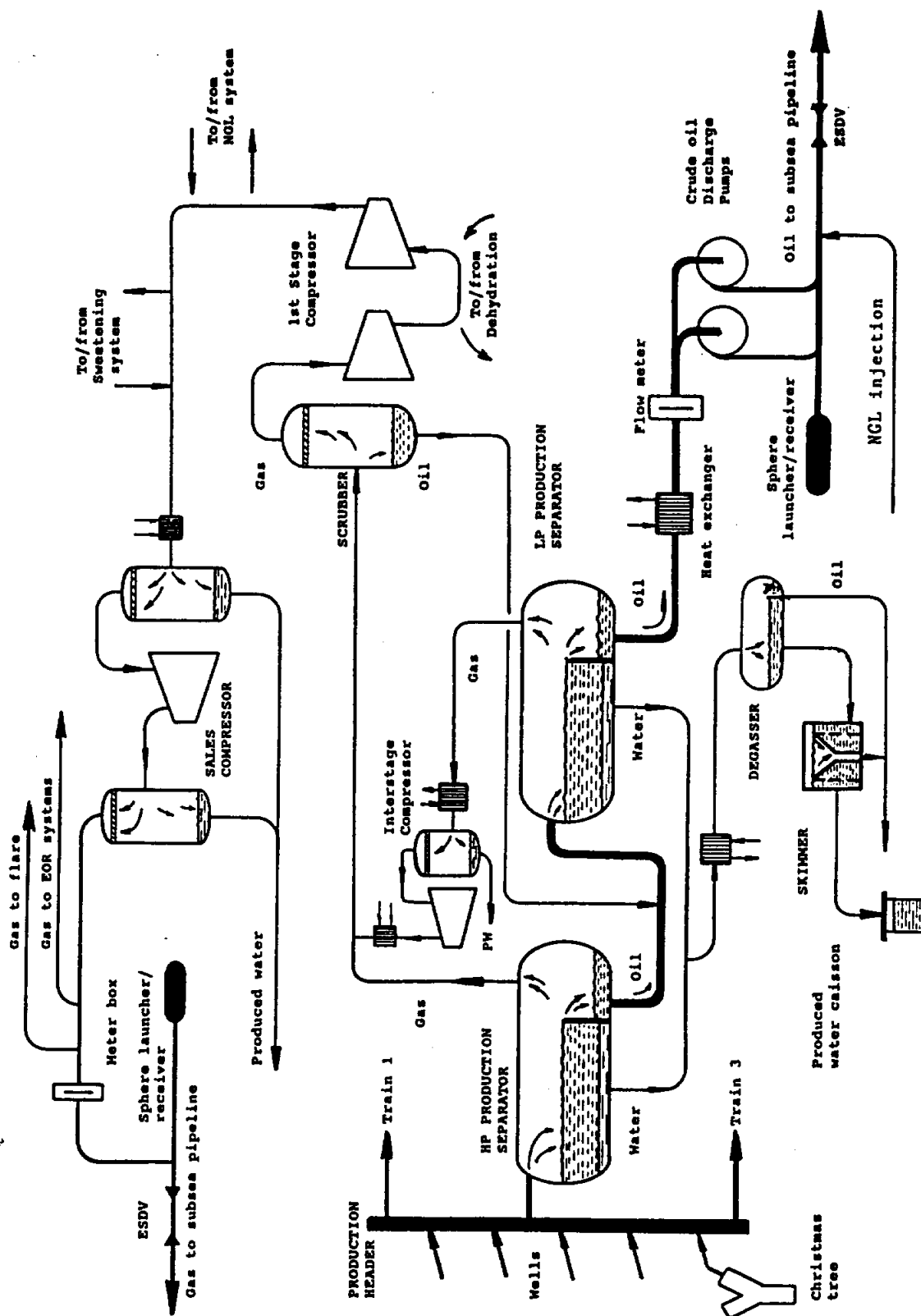
A sketch has been prepared to assist in the explanation of the hydrocarbon process equipment employed on an oil production installation.

#### **i) WELLHEADS**

The oil process commences at the christmas tree where oil at full reservoir pressure is admitted to the installation and reduced in pressure to approximately 450psig (30 bar) prior to entry into the production header or the well test separator.

#### **ii) PRODUCTION HEADER**

The production header is essentially a manifold which receives oil from all the wells on the installation (up to 60) and redistributes it to a number of process trains (up to 4). The process trains are identical and only one has been shown on the sketch in the interests of clarity. From the production header the oil enters the first of a series of production separators operating at successively lower pressures.



PRODUCTION OF OIL AND ASSOCIATED GAS

### iii) TEST SEPARATOR

The test separator is identical to the production separator in all but size and fulfils the same function as the test separator described in the gas process.

### iv) PRODUCTION SEPARATORS

The number of production separators employed will be dependant on the volume and pressure of the liquids entering the system but most installations require at least two and occasionally three per train.

The production separators facilitate the separation of oil, associated gas and water. The removal of gas is assisted by the reduction in pressure to atmospheric or near atmospheric conditions (45psi - 3 bar), whilst the separation of oil from the water relies on an oil/water interface. The water is disposed of via the produced water system whilst the oil is virtually ready for export. (The export oil is referred to as "dead crude" if processing was completed at atmospheric pressure whilst "live crude" describes an oil processed at a pressure slightly above atmospheric.)

### v) CRUDE OIL EXPORT

Prior to export the crude oil will normally be subjected to cooling, metering, injection of natural gas liquids (NGL) and a significant increase in pressure by the discharge pumps.

- a) **Cooling.** The temperature of oil produced from a deep reservoir can be considerable, occasionally in excess of 180°C (380°F). Consequently, a number of heat exchangers may be deployed prior to, between and after the various stages of separation to effect a reduction in crude oil temperature. This will assist in the separation of oil from water and in the stabilisation of the crude prior to export.
- b) **Metering.** Due to the fact that oil is normally transported by a subsea pipeline that is frequently shared with other installations, it is most important that the quantity of oil exported is measured in order that each installation may be accredited with it's just deserves. The oil is metered prior to the injection of (NGL) which is measured separately.
- c) **NGL injection.** The disposal of NGL by injection into the crude oil prior to export is analogous to the re-injection of condensate encountered on gas production installations. The process is known as "spiking" and transforms a "dead crude" into a live one.

The practice of spiking crude can only be performed on pipelines which terminate at a refinery suitably equipped to handle live oils.

- d) **Pumping.** Crude oil must be subjected to a considerable increase in pressure (750 psig-50 bar) to facilitate transportation by subsea pipeline. The discharge pumps are generally of a two stage centrifugal type, electrically powered through a synchro-torque variable speed coupling which can be adjusted to suit fluctuating oil production.

In common with gas producing installations the export pipeline is fitted with a sphere launcher/receiver and an emergency shutdown valve (ESDV).

## **2 ASSOCIATED GAS**

The quantities of gas associated with crude oil production can be considerable with some of the larger northern sector oil installations producing more gas than some of the unmanned satellite installations in the southern sector of the North Sea. The quantity of gas produced largely dictates the method of disposal and processing arrangements required.

### **2.1 THE GAS PROCESS**

The main objective of the gas process is to produce a gas which complies with the dew point (hydrocarbon and moisture) criteria specified for the subsea pipeline to ensure the avoidance of problems associated with corrosion, hydrate formation and the build up of condensed liquids. Basically this involves the removal of water, natural gas liquids (NGL) and gaseous impurities such as hydrogen sulphide ( $H_2S$ ) and carbon dioxide ( $CO_2$ ), should they occur.

#### **i) PRODUCTION SEPARATOR**

The gas process commences at the production separator where the reduction in pressure facilitates the vapourisation of gas from the crude oil. Two stages of separation are shown in the sketch but three successive stages of pressure reduction are frequently employed.

Gas from the H.P. separator passes directly to the inlet scrubber whilst gas liberated from the L.P. separator must undergo compression, cooling and scrubbing (liquid removal) before recombining with the H.P. gas.

#### **ii) INLET SCRUBBER**

The inlet scrubber is concerned primarily with liquid removal prior to the gas entering the first full stage of compression. Liquids removed may be returned to the inlet of the L.P. production separator, or they may be disposed of via the produced water system, depending on the design of the plant.

#### **iii) COMPRESSION**

Gas processing involves a considerable number of compression stages, due to the fact that associated gas is released from the crude oil at relatively low pressures and requires elevation to in excess of 1,000 psig (70 bar) for export and 6,000 psig (420 bar) for enhanced oil recovery re-injection.

The inclusion of gas compressors greatly complicates the process plant as each unit must be provided with suction and discharge scrubbers and heat exchangers in order to avoid the dangers associated with condensed liquid carry over into the machinery. Both electrically powered reciprocating and gas turbine driven centrifugal compressors are used extensively offshore, the centrifugal types favoured for high volume, low to medium pressure service whilst the reciprocating variety are more suited to low volume, high pressure duties such as gas re-injection into the reservoir.

#### **iv) INTERMEDIATE PROCESSING**

At this stage in the process the gas is relatively moisture free and the subsequent processing required will be dependant on the condition of the gas as it left the reservoir. Whilst water removal and compression equipment are common to all installations, dehydration, NGL removal, stabilisation and sweetening facilities are only incorporated as and when required. These intermediate process

arrangements will be discussed on completion of this section and their take off points (if required) can be seen on the Production of Oil and Associated Gas sketch.

#### v) EXPORT

Depending on the quantities produced the process gas may be sold, used for enhanced oil recovery (EOR), fuel gas, or flared.

##### a. Sale

When substantial quantities of associated gas are produced, which can account for up to 20% of the installations total hydrocarbon output, the financial returns may justify the construction of a subsea pipeline to facilitate the transportation and sale of the gas.

##### b. Enhanced Oil Recovery (EOR)

Enhanced oil recovery is an essential feature of the oil production process and associated gas can be utilised for re-injection into the reservoir or for gas lift operations. Such is the demand for gas for EOR that installations frequently import gas through a subsea pipeline when their own reserves are inadequate.

##### c. Fuel Gas

Virtually all installations are self-sufficient in fuel gas which is used to fire regeneration boilers, gas turbine driven alternators and compressors. The fuel gas is often produced as a bi-product of processes such as NGL removal and stabilisation.

##### d. Flaring

The flare on an oil producing installation burns continuously providing the means of disposing of unsaleable and toxic gases, and any gas surplus to requirements produced during periods of plant start up or maintenance.

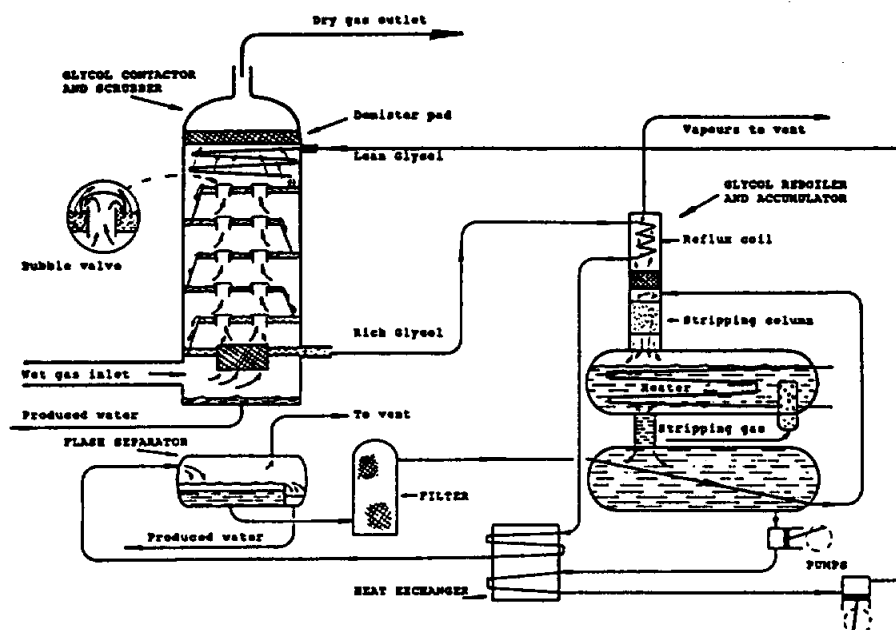
Where the gas is destined for sale it will undergo recompression prior to being transported to an onshore reception facility by subsea pipeline. The pipeline will include a metering box, sphere/launcher receiver and an emergency shutdown valve (ESDV) identical to the arrangements employed on a gas production installation.

## 2.2 THE DEHYDRATION PROCESS

The function of the glycol contactor, dehydration or absorption tower is to dehydrate export gas to ensure that the dew point temperature is below that point at which moisture condensation and thus hydrate formation may occur in the subsea pipeline.

The dehydration process is based on the strong affinity that glycols have for water, they are said to be hygroscopic and triethylene glycol (TEG) is chosen in preference to other glycols because of its greater ability to resist the high temperatures associated with the regeneration process. At the commencement of the dehydration process the "dry" glycol is referred to as being in the "Lean" condition whilst on completion of water absorption it is described as being "Rich".

The sketch shows a typical dehydration/regeneration plant.



## GAS DEHYDRATION PROCESS

### i) DEHYDRATION

The main function of the contactor is to provide conditions conducive to the water absorption process, that is the thorough mixing and agitation of the glycol and process gas. It consists of a tall, vertical pressure vessel that is divided into numerous sections by horizontal trays fitted with non-return or "bubble" valves. Lean glycol entering the top of the vessel cascades downwards flooding each tray in turn whilst the process gas flows upwards passing from section to section through the non-return valves.

The non-return valves actually force the gas to bubble through the glycol and the intimate contact that this affords greatly enhances the water absorption process. Eventually dry process gas emerges from the top of the contactor after having first passed through a demister pad designed to remove any entrained glycol. The rich glycol accumulates in the base of the vessel prior to entry into the regeneration plant.

Throughout the dehydration process the temperature of the glycol must be maintained at approximately 2 to 3°C above that of the process gas to prevent the condensation of liquid hydrocarbons into the glycol.

### ii) REGENERATION

The dehydration process benefits from high process pressure and low process temperature, conditions which increase the water absorption capacity of the glycol. In the regeneration process the conditions are reversed in order to encourage the release of water vapour and a return of the glycol to the lean condition suitable for re-circulation.

The main components of the regeneration plant are the flash separator which reduces the glycol pressure to atmospheric, and the reboiler where the actual drying out or purification process takes place.

The sketch shows the main component parts of the system.

**a. The Reflux Coil**

The reflux coil, or to give it its correct title the Reboiler Vapour Condenser is located in the top of the stripping column and is essentially a heat exchanger whose function is to provide pre-heat to the rich glycol entering the regeneration system and to reduce glycol losses by encouraging the condensation of glycol from the hot gases and water vapours leaving the reboiler drum.

**b. Flash Separator**

The flash, or condensate separator operates at atmospheric pressure and provides 3 phase separation. Process gas is released to the L.P. vent stack, water and condensate to the produced water system, and the glycol proceeds to the filtration package.

**c. Filtration Package**

Glycol being a viscous liquid has a tendency to foam and impurities in either liquid or solid form accentuate this tendency. The flash separator provides for the removal of liquid impurities whilst the filtration package removes solid particles.

**d. Heat Exchangers**

The glycol regeneration process involves a considerable transfer of heat both to and from the glycol and a number of heat exchangers are employed to increase the overall efficiency of the operation.

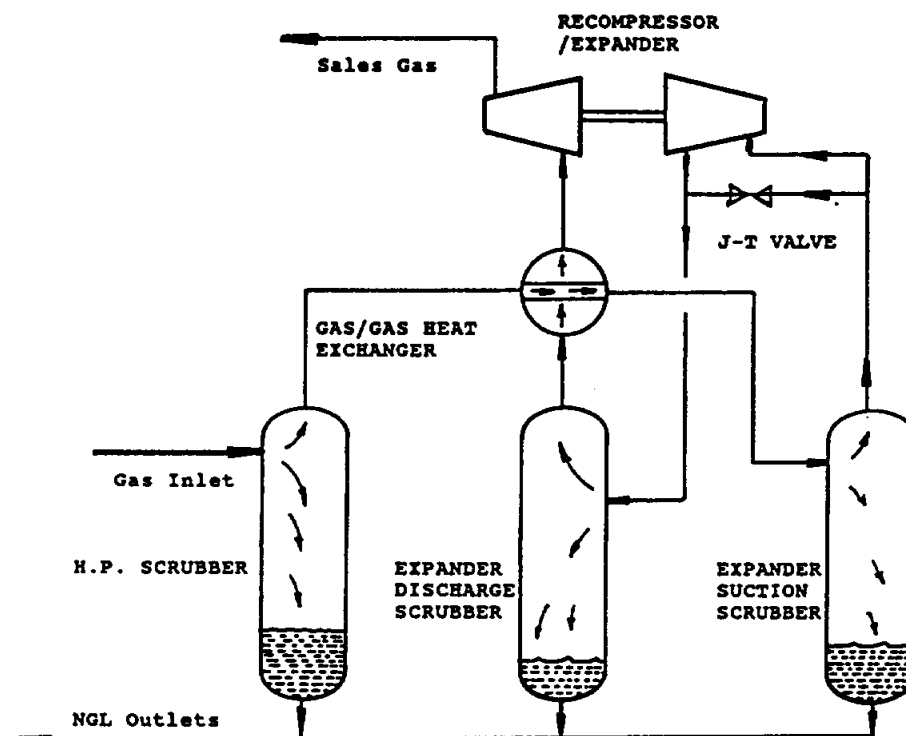
**e. Glycol Reboiler**

The purification of rich glycol is effected within a glycol reboiler or regenerator. The boiler, which operates at atmospheric pressure employs a combination of heat and stripping gas to remove entrained water.

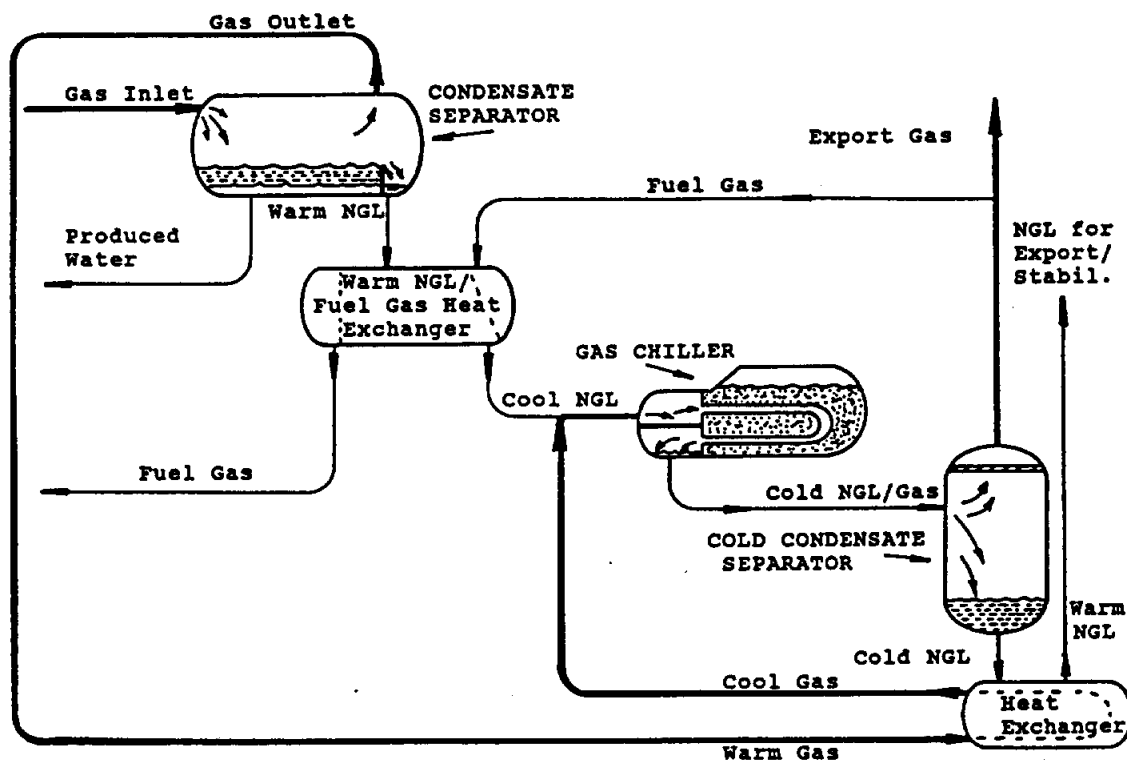
Rich glycol enters the reboiler drum at the base of the stripping column where it is heated to a temperature of 200°C (392°F) by gas fired burners (or electric heaters). Ideally a slightly higher temperature would be preferred because a temperature of 200°C (392°F) will only guarantee a glycol purity of 98.5%. Unfortunately chemical breakdown of the glycol commences at 204°C (400°F) and the oxalic and glycolic acids produced are highly corrosive. To compensate for the temperature limitations of the glycol a stream of stripping gas (fuel gas) is admitted into the base of the reboiler drum. The gas enhances the separation effect by reducing the partial pressure of the water vapour which permits an improvement in glycol purity to 99.9%, the value required by the dehydration process.

The lean glycol leaving the base of the reboiler drum is temporarily stored in the glycol accumulator, prior to cooling and subsequent transfer to the glycol contactor.

### THROTTLING PROCESS



### REFRIGERATION PROCESS



### REFRIGERANT PLANT



### 2.3 NATURAL GAS LIQUID (NGL) REMOVAL

Natural gas consists of a complex mixture of hydrocarbon products, primarily methane and ethane but including heavier gaseous hydrocarbon fractions such as butane and propane which possess boiling points within the ambient temperature range. These heavier fractions readily condense, are referred to as natural gas liquids (NGL) and can account for as much as 10% of the total oil output of an oil production installation. The more volatile of these liquid fractions are referred to as condensates and tend to be associated more with gas producing installations.

The function of the NGL system is to create conditions conducive towards the condensation and subsequent separation of the heavier gaseous fractions from the process gas to ensure compliance with the hydrocarbon dew point criteria specified by the subsea pipeline.

In common with the majority of hydrocarbon process operations the removal of NGL is effected using very basic principles of fluid and thermodynamics, namely a reduction in temperature to encourage condensation followed by a sharp change in direction designed to throw out the heavy liquid phase thus formed. Sea water cooled heat exchangers provide the means by which the initial reduction in temperature is achieved with subsequent stages employing a throttling process, or a dedicated refrigeration plant.

#### i) THROTTLING

The NGL removal system employs two preliminary stages of cooling and NGL separation prior to the gas being subjected to a more drastic temperature reduction within either an expander/recompressor, or a Joule-Thomson valve.

The Joule-Thomson (J-T) valve is quite simply a throttling valve named after the pioneering scientists James Joule (whose name was given to the SI unit of energy) and William Thomson (later Lord Kelvin after whom the absolute temperature scale was named). It is used in preference to the expander/recompressor during periods of off-peak gas production.

The expander/recompressor is an extremely efficient piece of machinery which utilises the expansion of process gas to impart rotational movement to a turbine wheel which in turn drives the recompressor attached to the opposite end of the shaft.

Cold gas leaving the expander ( $-20^{\circ}\text{C}/-5^{\circ}\text{F}$ ) or J-T valve ( $4^{\circ}\text{C}/40^{\circ}\text{F}$ ) enters the discharge scrubber where any remaining NGL is deposited prior to recompression and export.

#### ii) REFRIGERATION

The lower sketch shows a simplified layout of a refrigerated NGL removal process. The majority of vessels employed are heat exchangers designed to improve the efficiency of the operation for whilst NGL removal benefits from a reduction in temperature the subsequent stabilisation process (if fitted) relies on heat for its effectiveness.

The initial separation of NGL and process gas takes place within the condensate separator. Gas leaving the separator is cooled prior to re-combination with NGL at entry to the refrigeration vessel where the subsequent reduction in temperature ( $-30^{\circ}\text{C}/-22^{\circ}\text{F}$ ) accelerates the condensation of any remaining NGL. The contents of the refrigeration vessel are discharged into the cold condensate separator where NGL is once again separated from the gas, the gas leaving the top of the vessel destined for export.

The disposal of NGL will be dependant on the quantity produced. The liquids may be injected into the crude oil export line, into a dedicated NGL pipeline or re-injected into the reservoir for recovery at a later date. When transportation by subsea pipeline is intended the NGL may be subjected to a stabilisation process in order to prevent problems created by the vaporisation of dissolved gases.

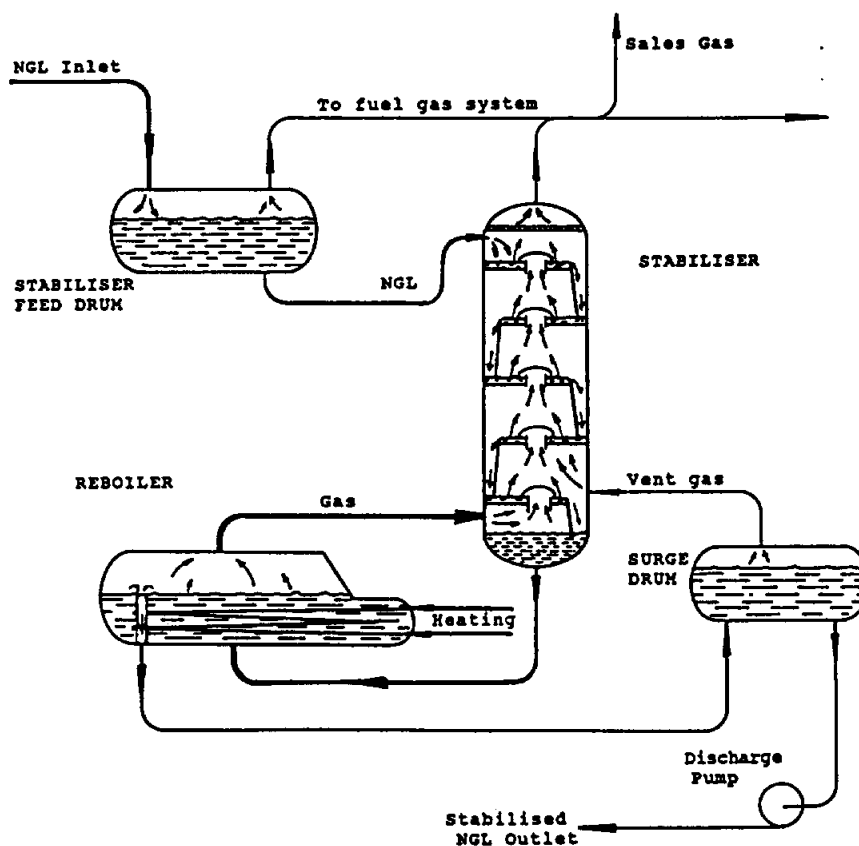
## 2.4 STABILISATION

The function of the stabilisation process is to remove the more volatile of the dissolved gases from the NGL. Removal of gases likely to vaporise in the subsea pipeline will ensure trouble free transportation and operation of equipment at the onshore reception facility.

Stabilisation is a distillation process which permits the composition of the NGL to be closely controlled by the addition of heat in a reboiler. The plant shares many similarities with the gas dehydration equipment.

The sketch below has been prepared to assist in the explanation of the process.

The NGL entering the top of the stabiliser gravitates downwards from tray to tray whilst hydrocarbon gases released from within the reboiler travel upwards effecting a stripping action designed to assist in the release of dissolved gases. The NGL eventually accumulates in the base of the vessel prior to transfer to the reboiler.



STABILISATION PROCESS

## **PART 3 ENHANCED OIL RECOVERY AND THE OIL DRIVE MECHANISM**

The pressure contained within a new oilfield can be considerable anything from 3,000 to 15,000 psig (204 to 1,000 bar) with 5,000 to 8,000 psig (340 to 545 bar) being representative of conditions prevailing in the North Sea. Unfortunately, being a liquid, oil is virtually incompressible and once production has commenced the natural reservoir pressure deteriorates rapidly and artificial means must be employed to enhance oil recovery if output is to be maintained at economic levels.

Basically enhanced oil recovery (EOR) involves either the injection of water or gas into the formation in order to increase the reservoir pressure, or the location of equipment within the production tubing to assist in the extraction of oil. Frequently a combination of methods are employed.

To understand fully the principles on which EOR rely we must first familiarise ourselves with the natural mechanisms which drive the crude oil from the reservoir. As stated previously it is the reservoir pressure which provides the motive force for oil production and the reservoir pressure is created by associated gas and/or formation water.

### **1. THE OIL DRIVE MECHANISM**

The driving force for the production of oil may be any one of four types depending on the rock formation surrounding the reservoir and the quantity of water and associated gas accompanying the oil.

#### **i) DEPLETION/SOLUTION DRIVE**

Depletion drive describes the situation encountered when reservoir pressure exceeds the bubble point pressure of the hydrocarbon gas. This means that there is no "free" gas available as it is all dissolved within the crude oil. The gas is produced with the oil and it is the expansion of the gas which provides the driving force.

Solution drive is extremely inefficient and can only be relied on to recover 5 to 25% of available oil reserves.

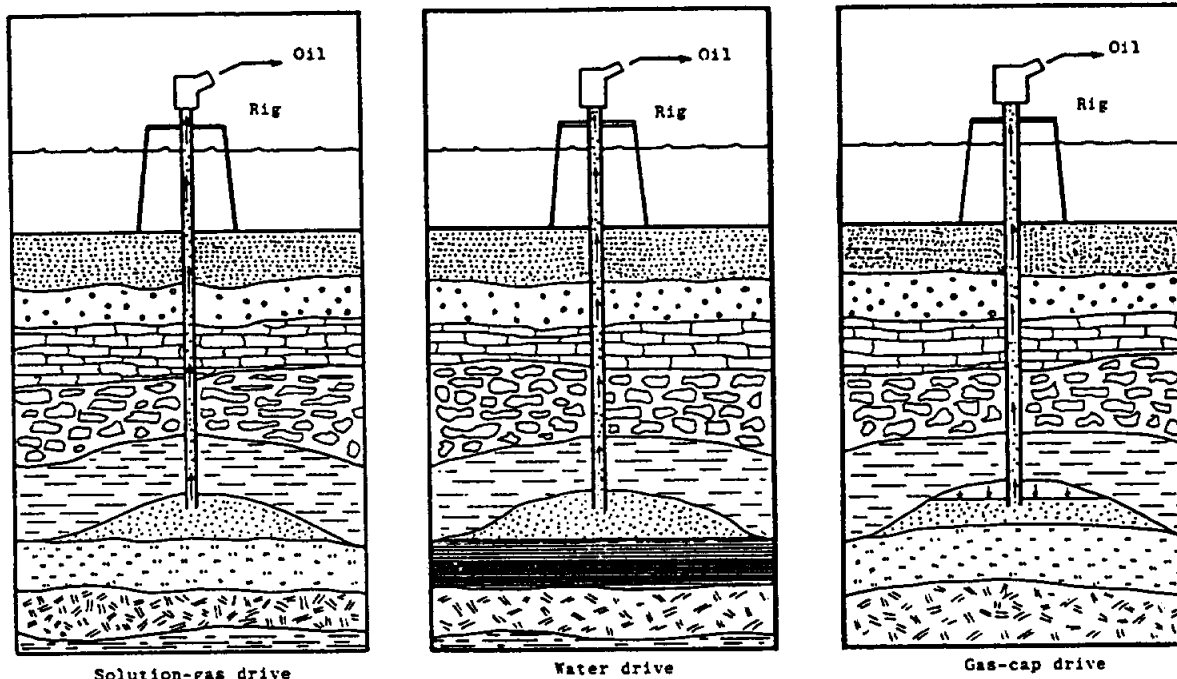
#### **ii) GAS DRIVE**

When the reservoir pressure is less than the gas bubble point pressure, a layer or pocket, of free gas exists above the oil. The gas acts like an accumulator, pushing the oil into the well bore and up to the surface and assists in the drainage of the upper reaches of the reservoir.

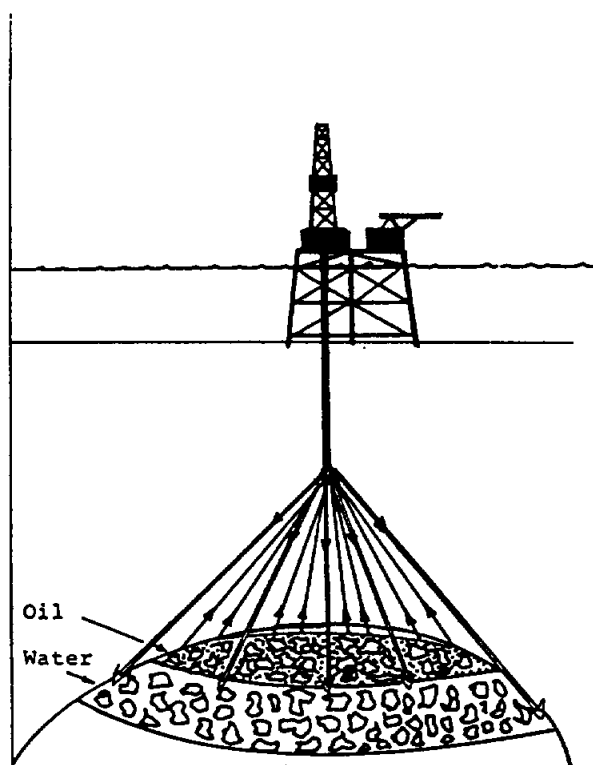
Gas drive permits the recovery of 20 to 40% of the oil contained within the reservoir.

#### **iii) WATER DRIVE**

Water drive is the most efficient of the natural recovery mechanisms relying on the expansion of the underlying water zone or aquifer to provide the driving force for oil production. Water is virtually incompressible so to be effective the volume of the water must be considerable in relationship to the volume of oil. Theoretically water drive can be used to recover 40 to 80% of the reservoir, unfortunately



## RESERVOIR DRIVE MECHANISMS



## WATER INJECTION

the large volumes of water produced with the oil from an ageing field limit the commercial viability of the process.

### iv) GRAVITY DRAINAGE

Gravity drainage is associated with steeply "dipping" reservoirs and this type of rock formation is conducive towards efficient oil output.

Initially oil production commences under the influence of depletion drive but as pressures fall the development of an overlying layer of free gas creates conditions more associated with gas drive.

## 2. ENHANCED OIL RECOVERY SYSTEMS

In order for oil to reach the surface the reservoir pressure must exceed the static head pressure created by the column of oil within the well bore. The pressure required can be considerable, approximately 4,000 psig (310 bar) for a well of depth 12,000 feet (3,650 metres). Frequently the reservoir pressure produced by an ageing field is

considerably less than this and enhanced oil recovery systems must be employed.

As previously stated, enhanced oil recovery may be effected by artificially increasing the reservoir pressure in order to supplement the natural oil drive mechanism, or equipment may be located within the production tubing of a well to help overcome the static head created by the column of oil.

The equipment associated with EOR considerably complicates life on board an oil production installation, the drilling derrick being in almost constant use involved in frequent modifications to the production tubings and in the drilling of new injection wells. For all that effort, the most efficient EOR systems can only economically recover 35 to 45% of the total oil contained within the reservoir, hence the description of oilfield capacity in terms of "recoverable reserves". This contrasts sharply with the exploitation of a gas field which can be almost literally sucked dry.

The four most widely used EOP techniques are:-

1. Water Injection
2. Gas Injection
3. Gas Lift
4. Submersible Deepwell Pump

## 2.1 WATER INJECTION

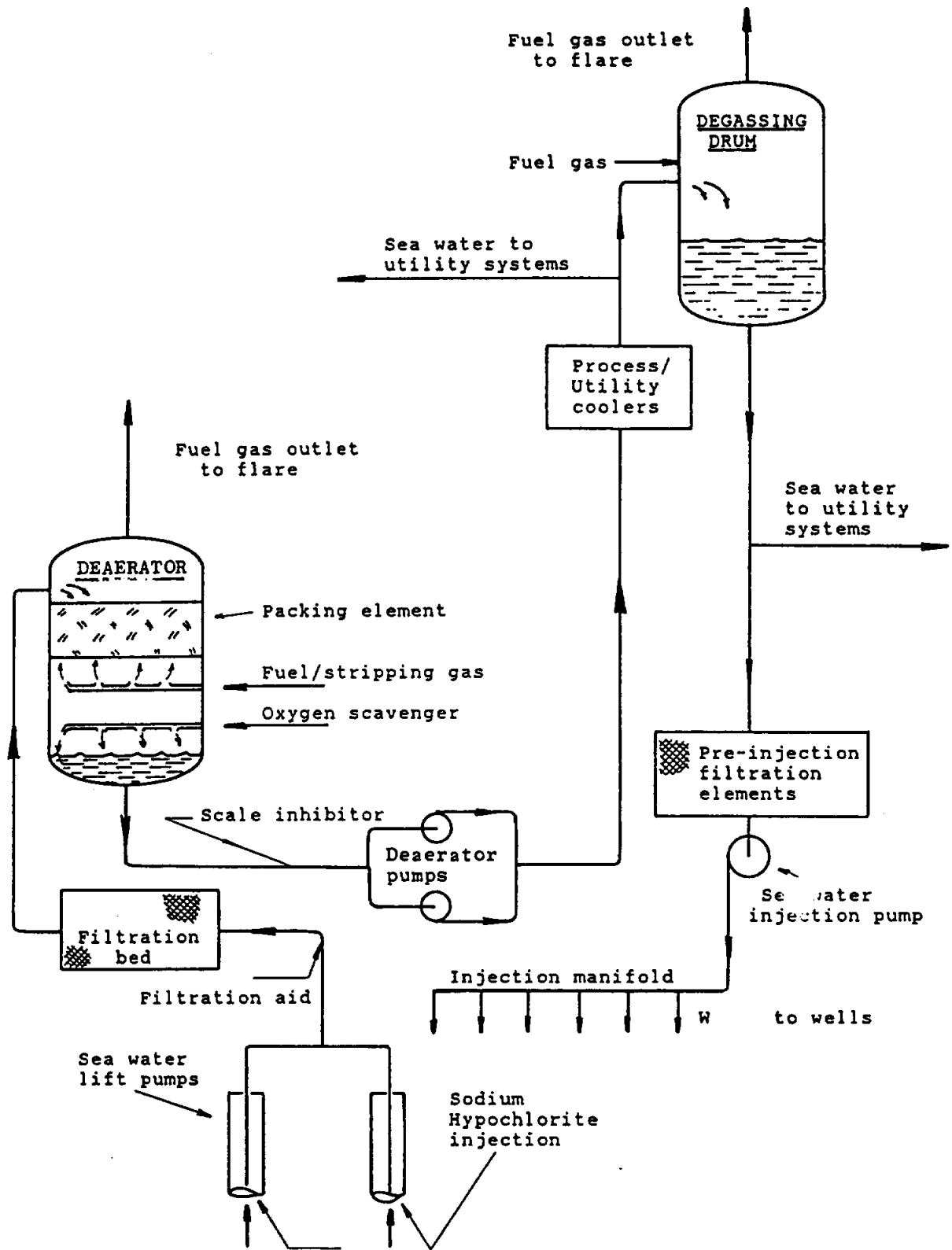
Water injection provides a relatively cheap and efficient means of improving oil production from a depleted field and it is used extensively in the North Sea. The water is injected under pressure into the flanks of the oil bearing strata through purpose drilled wells (or redundant oil wells). Water entering the oil bearing rock displaces any remaining particles of oil and the reduction in free space increases the reservoir pressure.

Water for the injection system may be drawn from the sea or from the produced water system. Produced water consists of water removed from the crude oil during processing and is particularly suitable for re-injection due to the absence of dissolved oxygen. A mature oilfield produces a considerable quantity of formation water, typically four times as much water as oil and the disposal of up to 150,000 barrels (21,000 tonnes) a day can present problems. If the water is to be pumped in to the sea, it must first be cleaned to ensure that all traces of oil and condensate are removed to avoid the risk of pollution and so re-injection effectively kills two birds with one stone.

The sketch overleaf shows a simplified lay out of a typical general service sea water system that provides water for both reservoir injection, and process and utility equipment. The system employs relatively complex filtration and purification arrangements to ensure that the water destined for reservoir injection is scrupulously clean. The fine pores contained within the hydrocarbon bearing rocks must be protected against impurities that could restrict the drainage of oil and reduce the output of the reservoir.

### i) SEA WATER LIFT PUMPS

Multi-stage, centrifugal submersible pumps installed within separate caissons provide the sea water to the system, the pump suction being dosed with Sodium Hypochlorite solution to combat marine growth and discourage microbiological activity.



SEA WATER INJECTION SCHEMATIC

## ii) FILTRATION PACKAGES

The sea water system contains two filtration packages, the first for general filtration of all sea water prior to entry into the deaerator and the second purely for filtration of injection sea water.

The first filtration vessel contains a graded filter bed consisting of typically anthracite, garnet and pea gravel which will remove solid impurities greater than 5 microns (0.0002ins) in size. The addition of a filtration aid (a positively charged polyelectrolyte) further enhances the efficiency of the operation.

The second filtration package employs a series of perforated stainless steel tubes covered with a woven fabric. Both filtration packages are periodically back-washed in order to clean the filtration medium of deposited solids.

## iii) DEAERATOR

Removal of dissolved oxygen greatly reduces the corrosive effect of sea water and will increase the operating life of the plant considerably. The deaerator vessel may utilise stripping gas (fuel gas) or evacuation to encourage the release of dissolved oxygen and the injection of an oxygen scavenger such as ammonium bisulphate ( $\text{NH}_4 \text{HSO}_3$ ) into the base of the vessel further improves the process. Efficient deaeration can reduce the oxygen content of sea water from 9.25 parts per million to less than 30 parts per billion.

Water leaving the deaerator is subject to further conditioning by the addition of a scale inhibitor designed to prevent the formation of insoluble sulphates and carbonates that can occur when sea water eventually mixes with the natural waters in the reservoir.

## iv) DEGASSING

The degassing vessel basically provides agitation to the sea water to assist in the removal of excess hydrocarbon gas. Water leaving the vessel supplies both platform utilities and the sea water injection system.

## v) INJECTION PUMP

The sea water is injected into the reservoir by immensely powerful (2,000kw) electric motor driven centrifugal multi-stage pumps which can generate water pressures ranging from 3,000 to 5,000 psig (205 to 340 bar).

The water injection wells are to all intents and purposes identical to production wells and include a christmas tree and mudline safety valve. They are also connected to the ESD system.

## 2.2 GAS INJECTION

Gas injection operates on similar principles to water injection, by artificially increasing the reservoir pressure. The process also provides the ideal means of disposing of the associated gas removed from crude oil when the quantities produced do not justify the installation of a subsea pipeline. The gas should not be thought of as lost because it can be recovered at a later date on completion of oil production.

The gas injection system consists of a high pressure compressor and distribution manifold which deliver gas to the reservoir at pressures of up to 6,500 psig (450 bar) through purpose drilled wells. Gas

destined for re-injection is subjected to the full purification process that sales gas would receive in order to avoid contamination of the reservoir and injection equipment.

In the future nitrogen injection could provide an alternative to process gas, the nitrogen being produced from a cryogenic air separation plant.

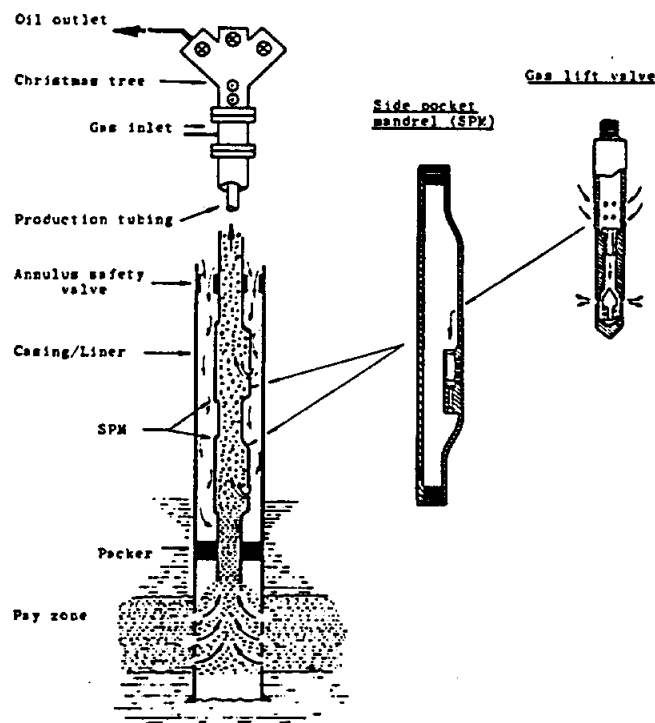
### 2.3 GAS LIFT

Gas lift valves and submersible pumps achieve the same end result by differing means and it should be remembered that both methods assist the reservoir oil drive mechanism and are not designed to produce from a field devoid of all natural pressure. The gas lift valves effect a reduction in static head pressure by reducing the specific gravity of the oil, whilst the submersible pump simply provides the oil with a helping hand in the form of a pressure boost.

Gas lift involves the re-injection of process gas into the production tubing in order to produce a foaming gas/oil mixture with a specific gravity considerably less than the naturally occurring crude oil.

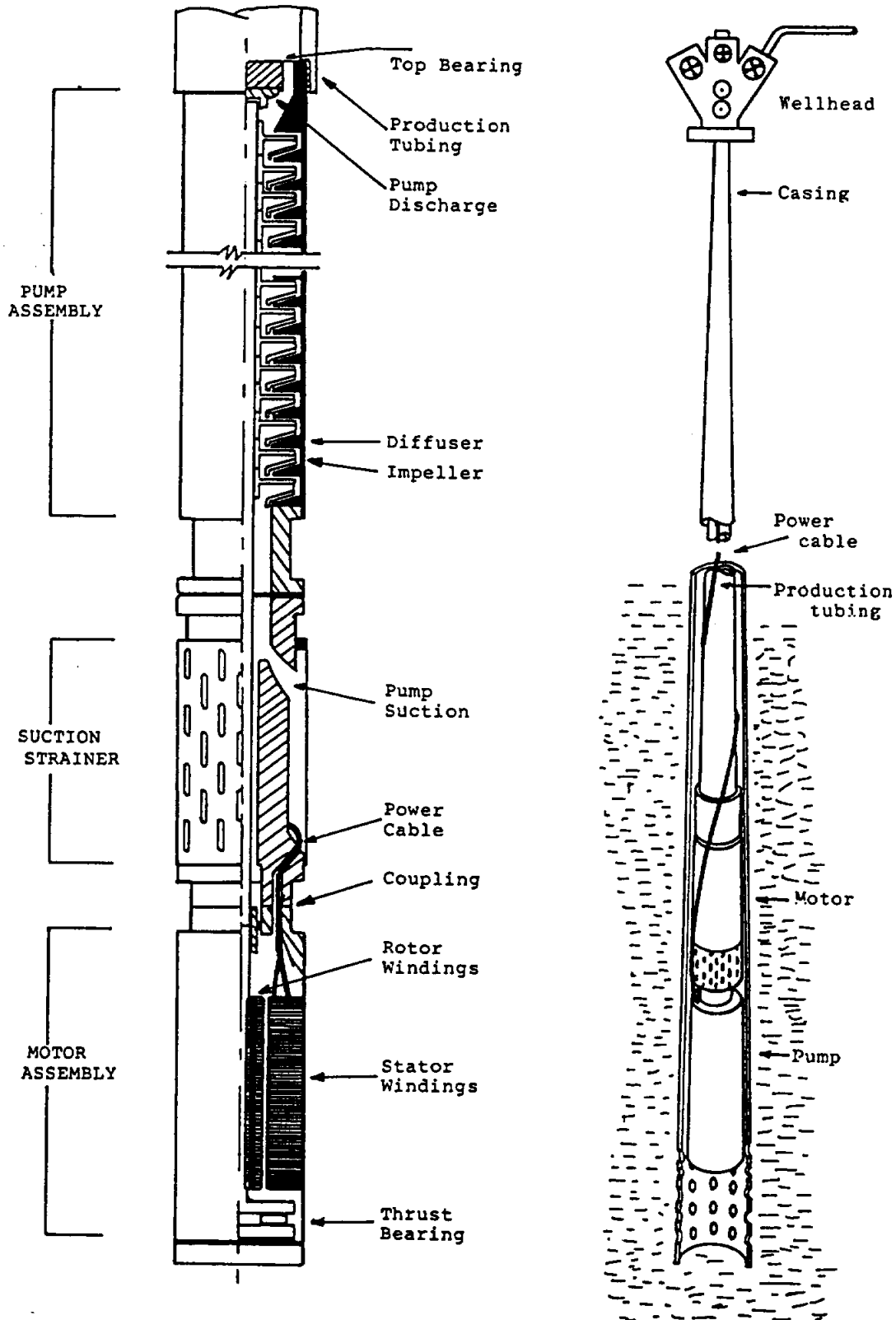
Process gas is introduced into the annulus space surrounding the production tubing through a connection on the wellhead. It then passes into the production tubing through a series of gas lift non-return valves, the flow being regulated by the pressure in the annulus.

The sketch below shows a general arrangement of the gas lift equipment. The non-return valves are located within eccentric tubular housings referred to as side pocket mandrels (SPM) which are run (installed) as part of the production tubing. The SPM's ensure that an unrestricted channel is maintained within the production tubing which permits the maximum flow of oil and the passage of the wireline tools employed to install and replace the gas lift valves.



GAS LIFT ARRANGEMENTS





SUBMERGIBLE DEEPWELL PUMP

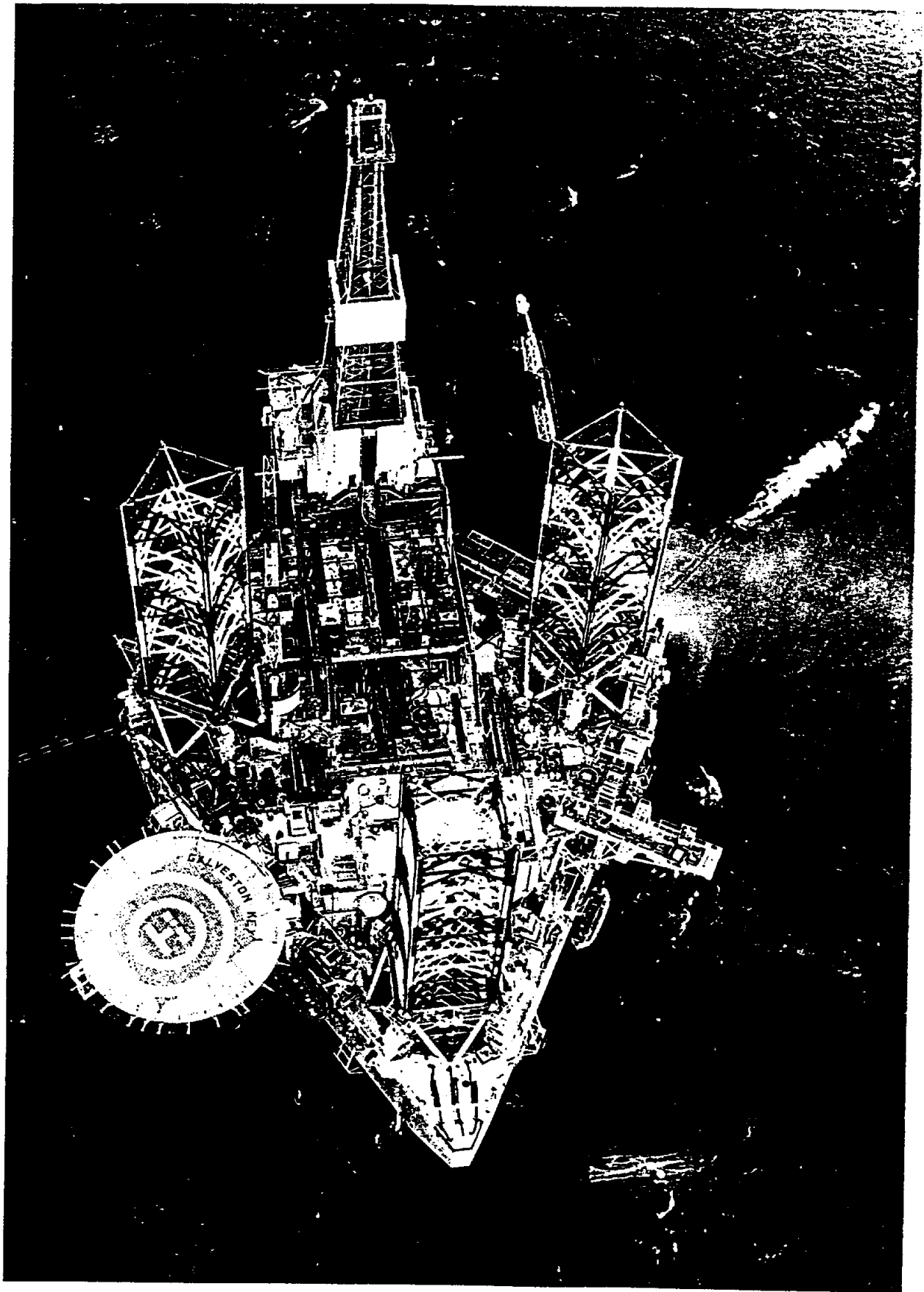
## **2.4 THE DEEPWELL/SUBMERGIBLE PUMP**

The deepwell, downhole, submersible or submergible pump assembly has evolved as one of the most successful and reliable enhanced oil recovery tools, being used extensively throughout the world.

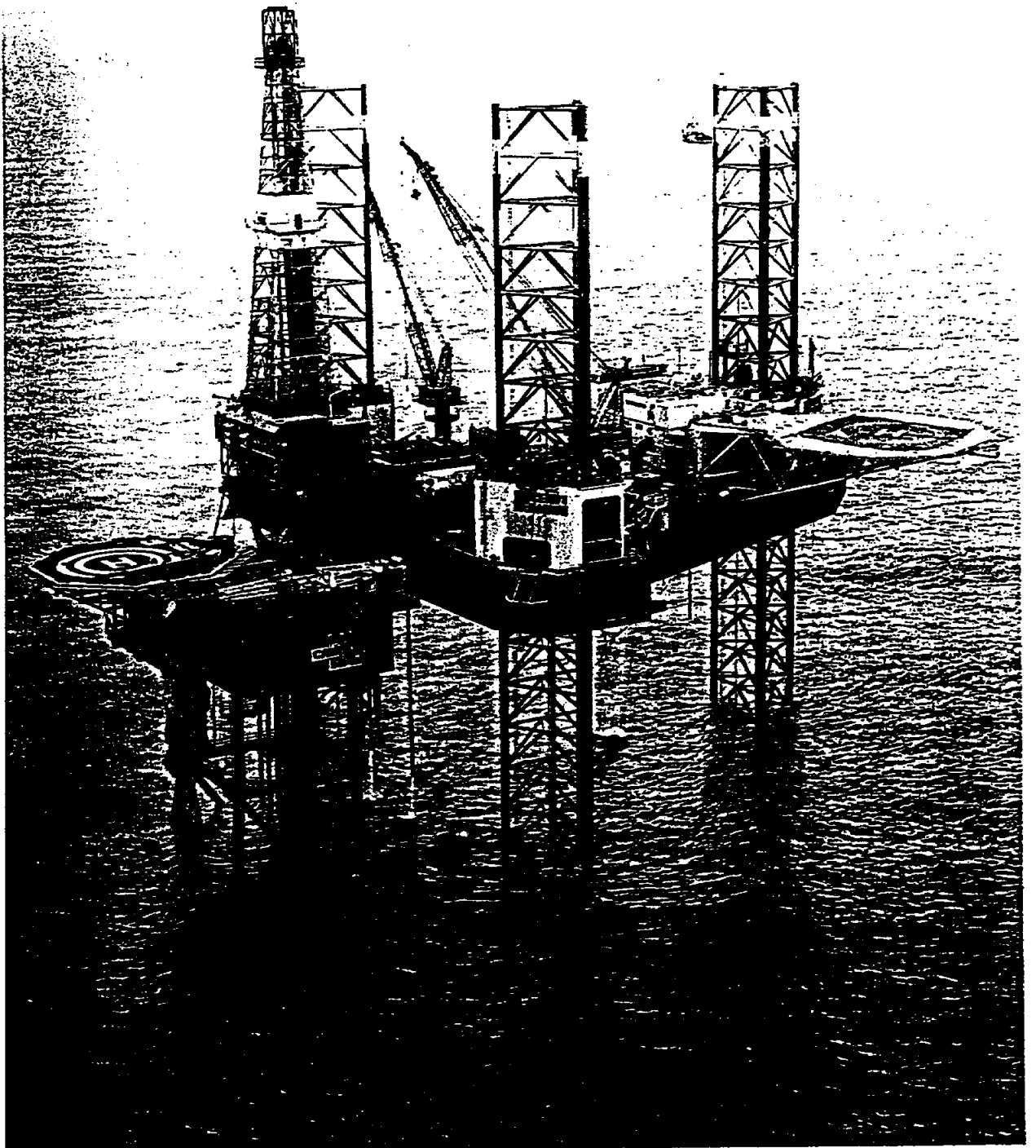
The unit consists of a multiple stage centrifugal pump and drive motor which is attached to the base of the production tubing and located within the intermediate casing or liner by a hydraulically activated packing device.

The pump units are individually tailored to suit the conditions pertaining to a particular well and up to 200 impellers may be used. A typical North Sea well employs a 100 stage pump driven by a 150 to 300 Kw electric motor which is capable of producing 13,000 barrels of oil a day at a surface pressure of between 100 and 300 psig (7 to 15 bar).

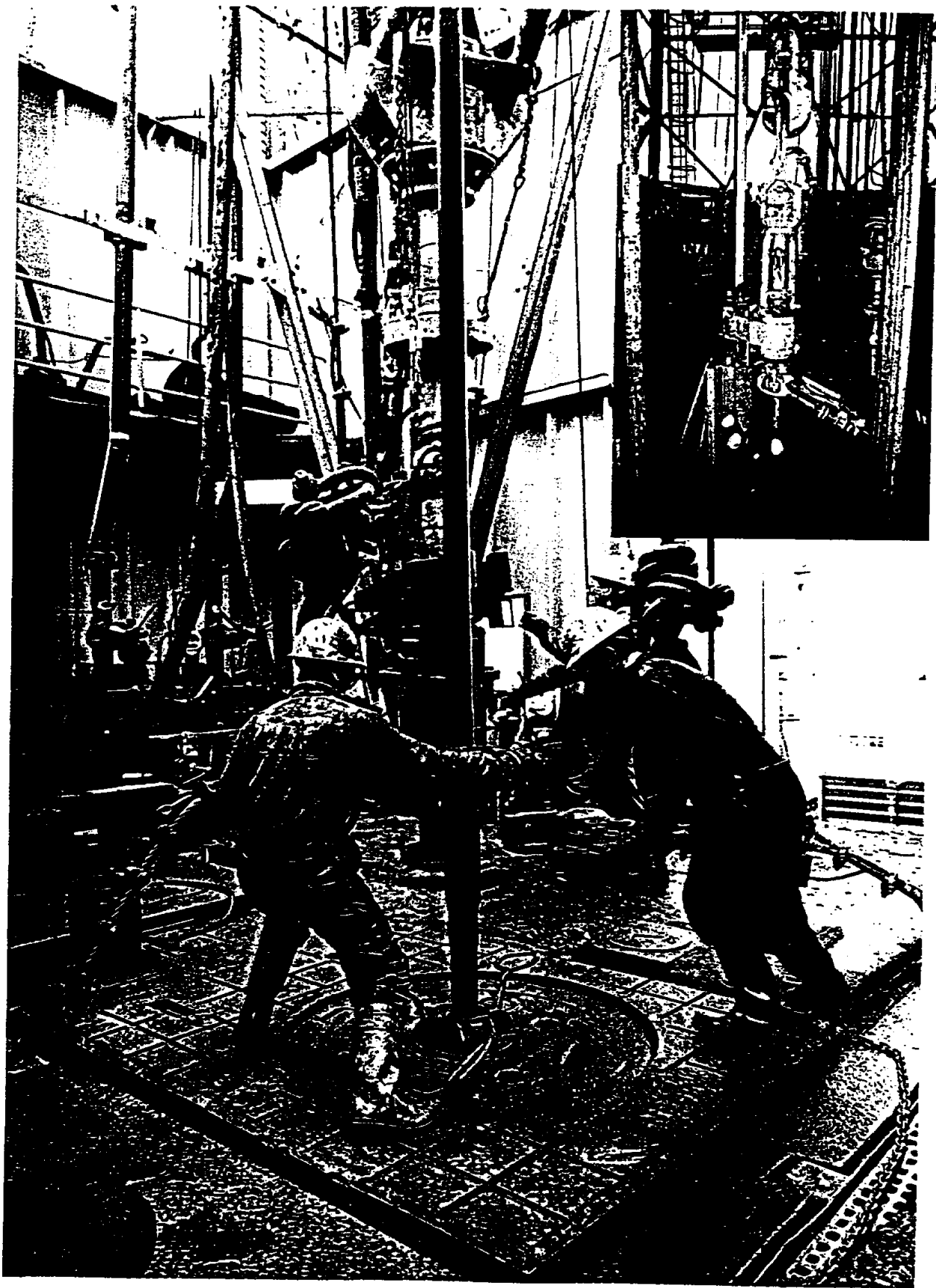
Future developments are likely to see the emergence of a hydraulically powered pump aimed primarily at the sub sea market where to-date, it has not been possible to use electrically powered pumps.



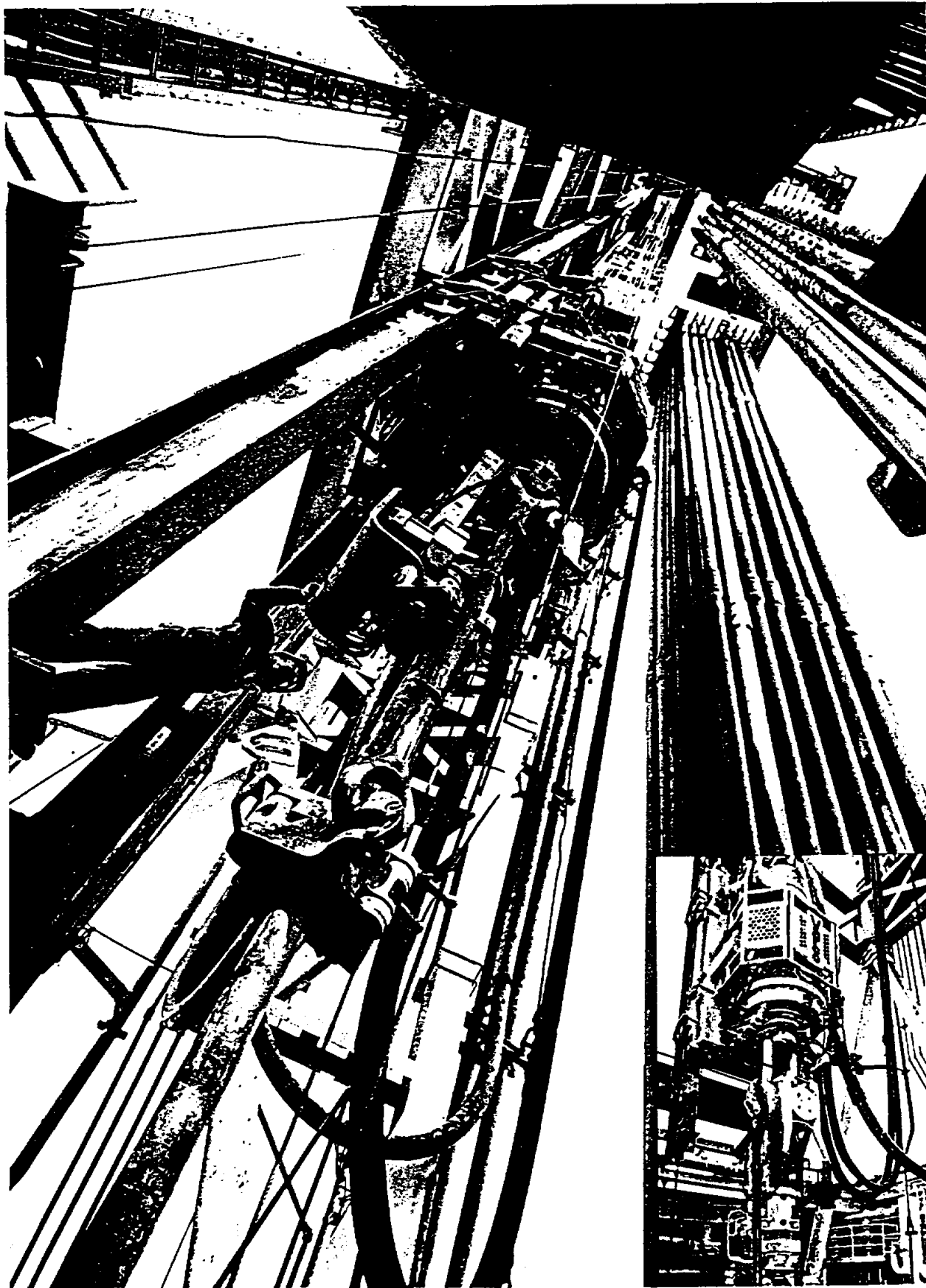
17 - The jack-up Galveston Key testing an appraisal well. The vent boom can be seen flaring the gas.  
The V door and pipe draw can be seen at the base of the derrick.



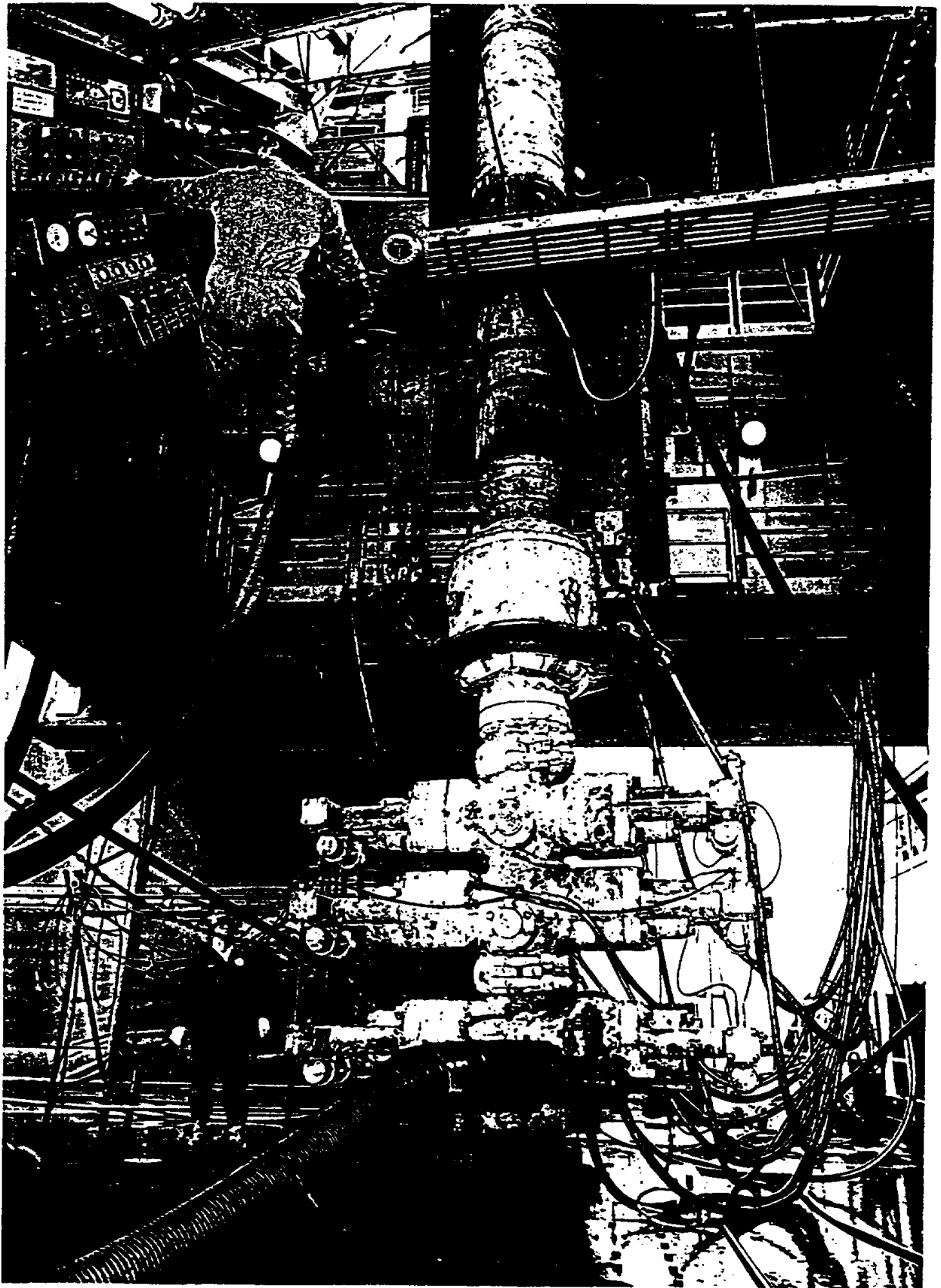
18 - The Ocean Benarmin jack-up with it's drilling derrick cantilevered over the Mobil Camelot 53/1a unmanned gas platform. The Benarmin is completing the wells following installation of the topside structure.



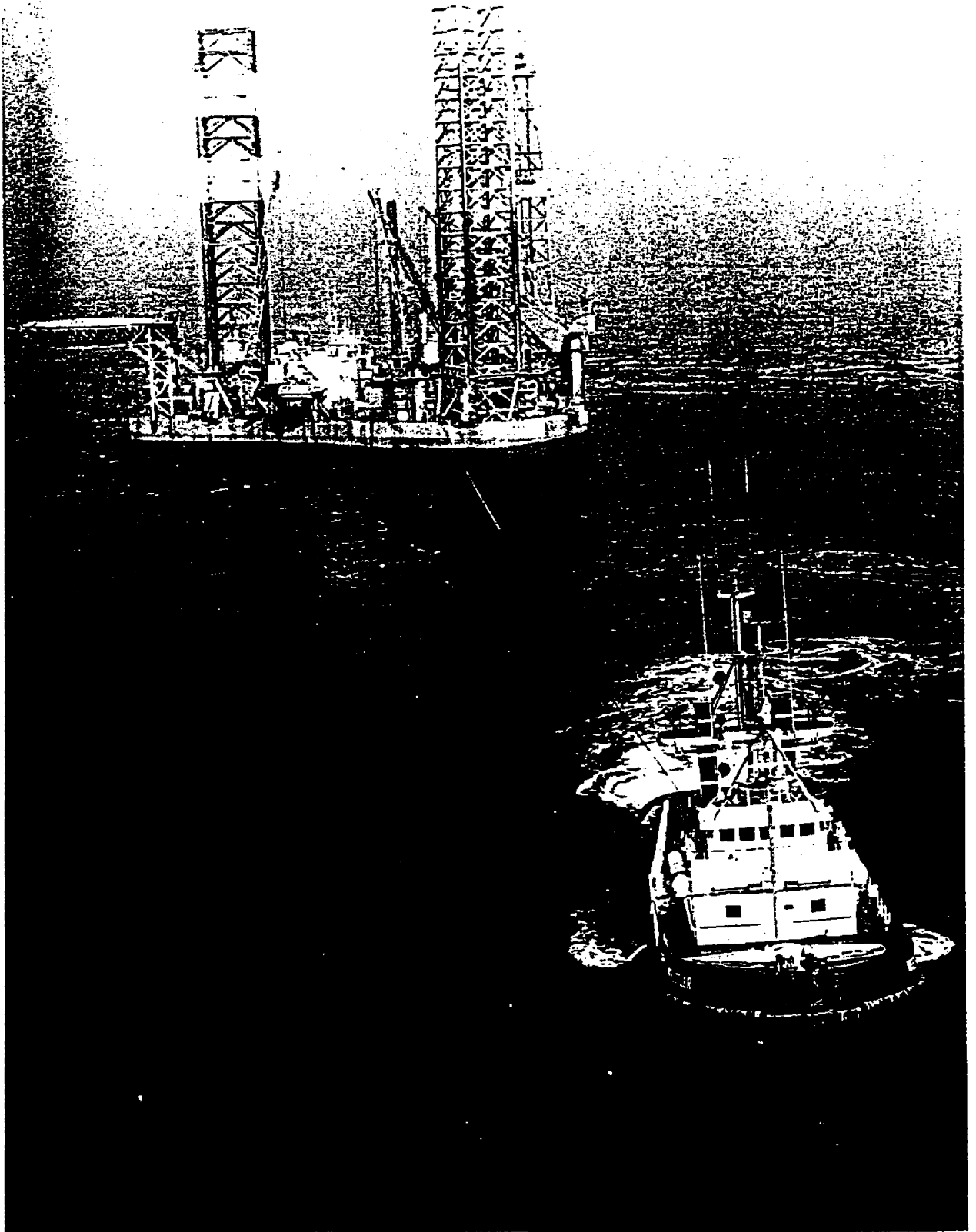
19 - Drill crew hard at work on the drill floor. Note the drill pipe stands standing vertically to the left of the picture.  
Inset - the drill crew are dwarfed by the travelling block hook, the gooseneck and rotary hose,  
the swivel and drive motor.



20 - Varco BJ top drive drilling motor undergoing an examination.  
The motor, guide rails and drill pipe stands are clearly visible.

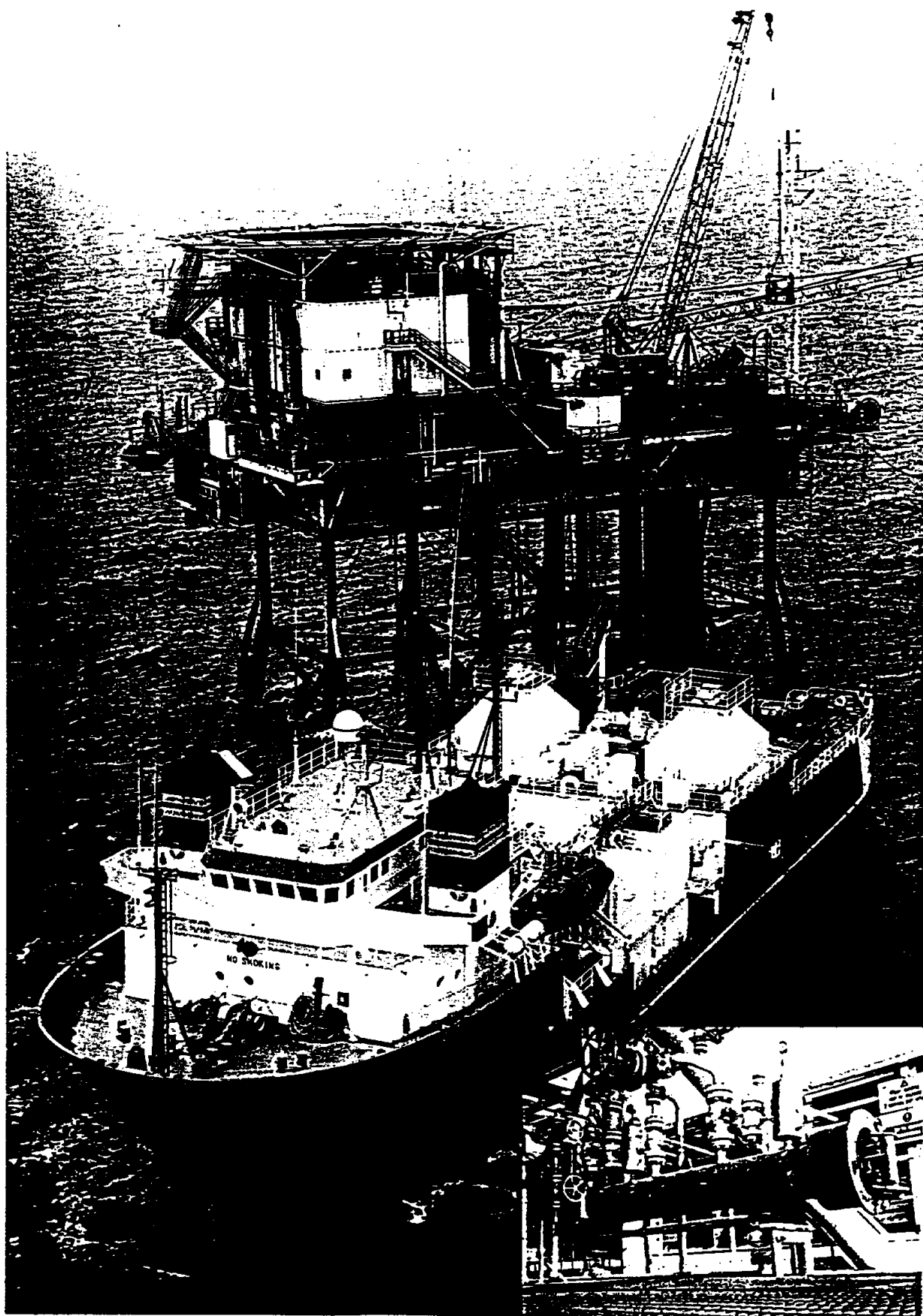


21 - Blowout preventer (BOP) stack piped up and ready for action.  
The stack consists of an annular BOP, twin, and single ram BOP's.  
Inset - the tool pushers console from where all the drilling activities are controlled.

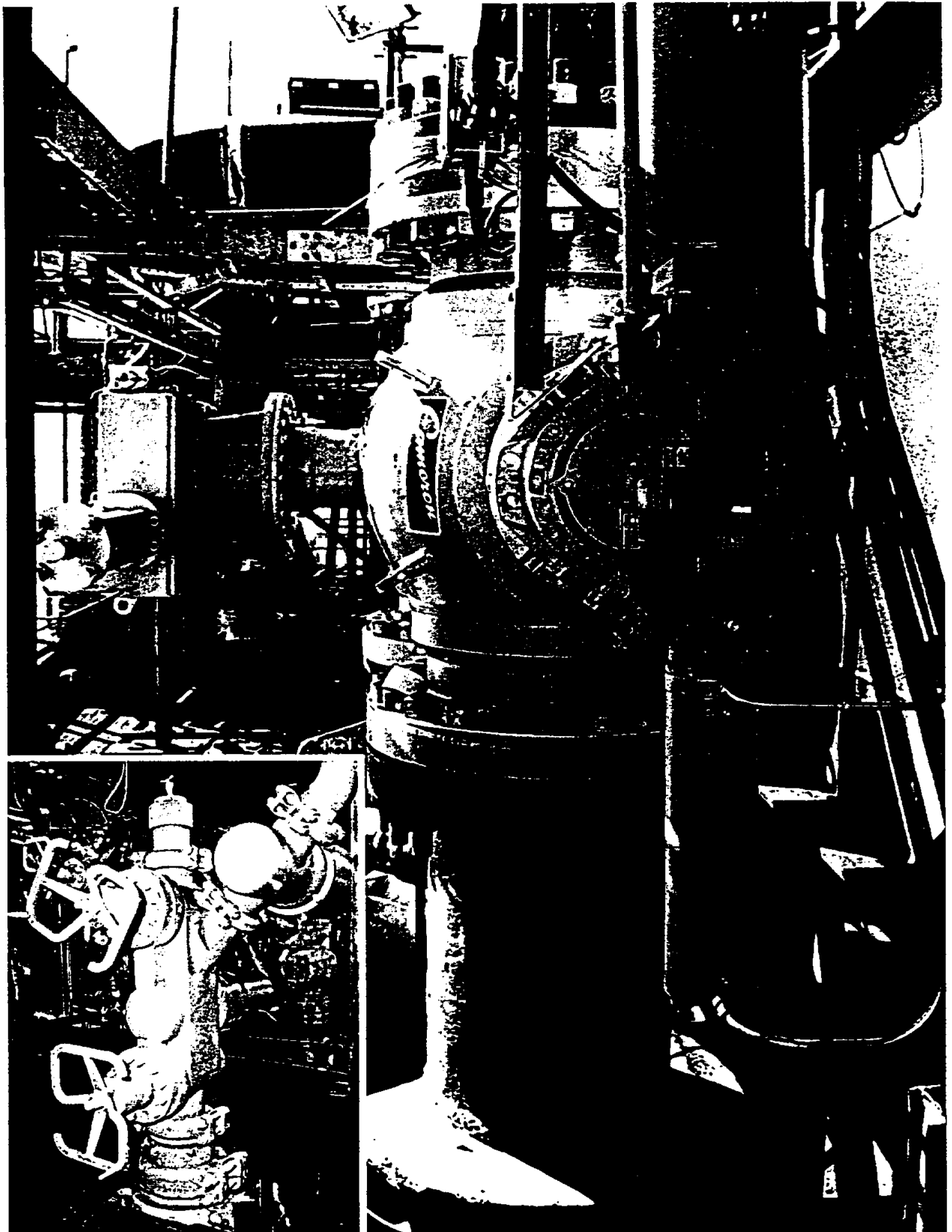


22 - Drilling programme complete the Arch Rowan is lowered to the water and towed to its new destination.  
The Wrestler is taking the tow.





23 - The Big Orange XVIII well service vessel alongside a gas production installation.  
Inset - sphere launcher, an interlocking door prevents inadvertent opening whilst the chamber is under pressure.



24 - Cameron Iron Works (Cooper Oil Tools) emergency shutdown valve (ESDV) installed on a subsea pipeline riser as part of the new regulations introduced after the Piper Alpha disaster. The fail safe actuator can clearly be seen as can the heat resistant cementitious coating on the pipeline below the valve.

*Inset - a solid block Veto Gray Christmas tree. On this particular tree the lower master and swab valves are manually operated whilst the upper master and wing valves are fitted with remote control actuators.*

# **Chapter Six**

## **UNDERWATER ENGINEERING**

### **PART 1. DIVING - INTRODUCTION**

1. Air Diving
2. Saturation Diving
3. Equipment
4. Vessels

### **PART 2. UNDERWATER SURVEYS**

1. Splash Zone Examination
2. Swimaround Survey
3. Non-Destructive Examination
4. Flooded Member Survey
5. Marine Growth Measurement
6. Scour Survey
7. Cathodic Protection Examination
8. Differential Settlement Survey
9. Air Gap Measurement

### **PART 3. SUBSEA WELLS.**

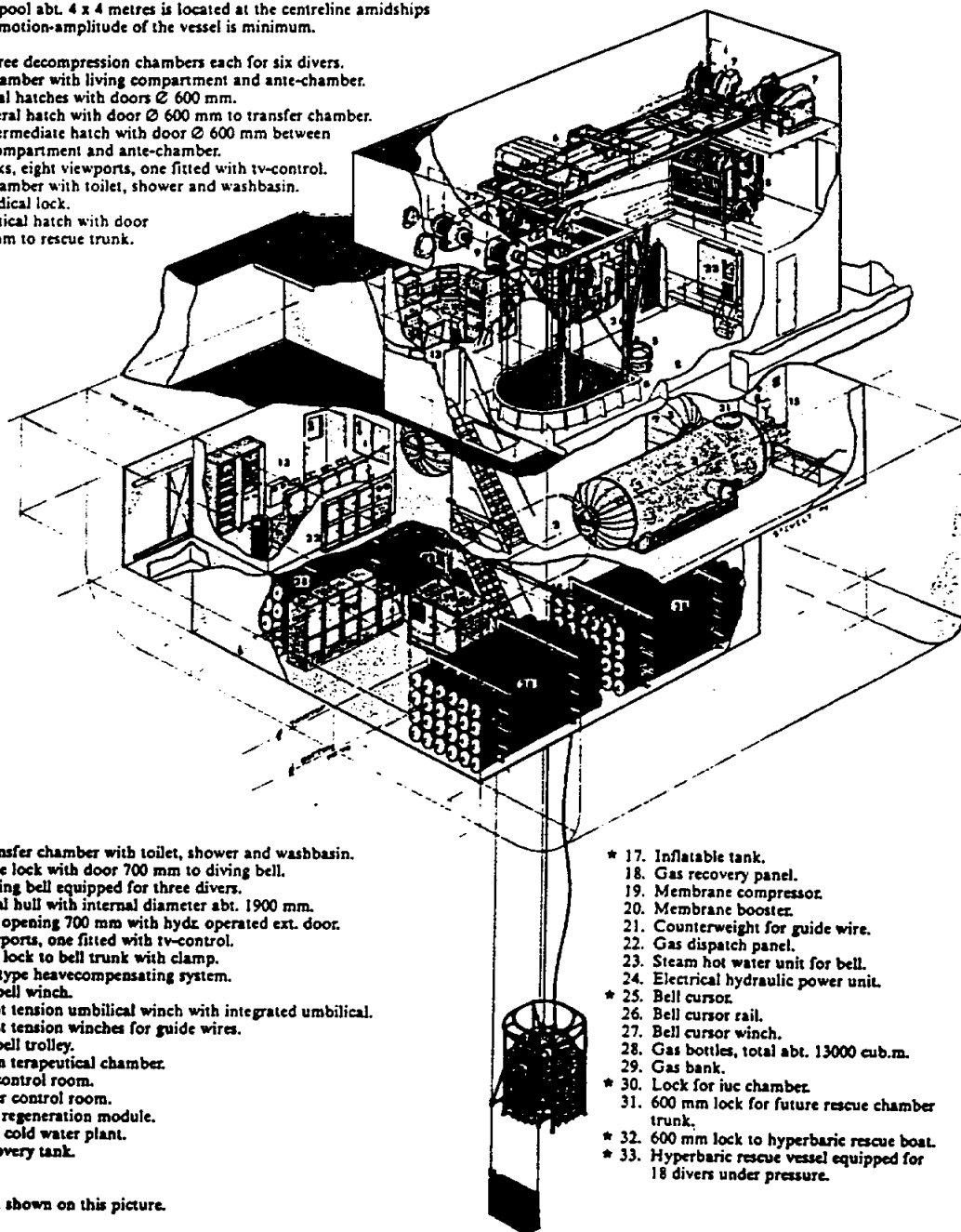
1. Subsea Wellhead Equipment
2. Future Developments

### System Summary

The vessel is fitted with a saturation diving complex, rated to 450 m depth, for 18 divers in round the clock service, with the possibility of operating two diving teams at different working depths and decompressing a third diving team simultaneously. The decompression chambers and the diving bell are equipped with gas reclaim system. The diving bell is provided with heave-compensating maincable and guidewires, which can be disconnected when need of sidehauling. Separate sidehauling-davits with winches are installed. Heave-compensation also provided for, when sidehauling. The diving bell is driven through the splashzone and moonpool by a cursor-system. The moonpool abt. 4 x 4 metres is located at the centreline amidships where the motion-amplitude of the vessel is minimum.

The diving system fulfils classification requirements of Det Norske Veritas.

1. & 2. Three decompression chambers each for six divers.
  - Each chamber with living compartment and ante-chamber.
  - Two axial hatches with doors  $\varnothing$  600 mm.
  - One lateral hatch with door  $\varnothing$  600 mm to transfer chamber.
  - One intermediate hatch with door  $\varnothing$  600 mm between living compartment and ante-chamber.
  - Six bunks, eight viewports, one fitted with tv-control.
  - Ante-chamber with toilet, shower and washbasin.
  - One medical lock.
  - One vertical hatch with door  $\varnothing$  600 mm to rescue trunk.



3. One transfer chamber with toilet, shower and washbasin.
  - Entrance lock with door 700 mm to diving bell.
4. One diving bell equipped for three divers.
  - Spherical hull with internal diameter abt. 1900 mm.
  - Vertical opening 700 mm with hydrc operated ext. door.
  - Six viewports, one fitted with tv-control.
  - 700 mm lock to bell trunk with clamp.
5. 700 mm lock to bell trunk with clamp.
6. Rucker type heavecompensating system.
7. Diving bell winch.
8. Constant tension umbilical winch with integrated umbilical.
9. Constant tension winches for guide wires.
10. Diving bell trolley.
11. 1500 mm therapeutic chamber.
12. Diving control room.
13. Chamber control room.
14. Internal regeneration module.
15. Hot and cold water plant.
16. Gas recovery tank.

- \* 17. Inflatable tank.
18. Gas recovery panel.
19. Membrane compressor.
20. Membrane booster.
21. Counterweight for guide wire.
22. Gas dispatch panel.
23. Steam hot water unit for bell.
24. Electrical hydraulic power unit.
- \* 25. Bell cursor.
26. Bell cursor rail.
27. Bell cursor winch.
28. Gas bottles, total abt. 13000 cub.m.
29. Gas bank.
- \* 30. Lock for iuc chamber.
31. 600 mm lock for future rescue chamber trunk.
- \* 32. 600 mm lock to hyperbaric rescue boat.
- \* 33. Hyperbaric rescue vessel equipped for 18 divers under pressure.

Item not shown on this picture.

## SATURATION DIVING COMPLEX (Stena Offshore Limited)

## **Part 1. DIVING**

Offshore installations are analogous to icebergs inasmuch as the bulk of the structure lies beneath the waves and as such the industry is heavily dependant on the diving fraternity for its continued well being. The offshore industry in the North Sea provides employment for nearly 1,500 divers who are involved in the installation, repair, maintenance and inspection of structures and pipelines and whilst the current trend is towards a reduction in diver intervention, there will always be a place for the levels of manual dexterity that only man can provide.

Diving operations may be divided into two categories which are dictated by water depth. For depths of less than 50 metres (165 feet) air diving techniques may be employed whilst greater depths necessitate a full saturation diving programme. Before discussing the various aspects of air and saturation diving, we should first consider the effects that prolonged immersion in deep water have on the human body, for it is in the sensitivity of the body to environmental change that dictates the type of equipment required for life support.

At normal atmospheric pressure the tissues of the human body are in a state of equilibrium with their surroundings, that is to say they are saturated with the dissolved gases that constitute air, primarily nitrogen and oxygen. This state of equilibrium or saturation, is disturbed the instant the diver enters the water.

As the diver descends the hydrostatic pressure on the body increases the gas absorption capacity of the tissues. Given sufficient time at any particular depth they will once again reach a point of equilibrium or saturation. The eventual ascent from saturation depth must be carefully controlled and include in water stops or pauses to permit the natural release of these newly dissolved gases if the diver is to avoid the "bends" (expansion of gas in the blood stream). This is a time consuming process and highlights the major difference between air and saturation diving. The air diver must restrict the depth and duration of his dive to prevent the body reaching the fully saturated condition.

### **1. AIR DIVING**

Air diving is used primarily for dives of short duration in water depths of less than 50 metres (165 feet) where excessive decompression times can be avoided. As the name suggests, the divers breathe compressed air which is supplied through an umbilical.

Air diving is used for the vast majority of underwater inspection and repair programmes carried out in shallow waters such as the southern sector of the North Sea where the strong tides impose a natural restriction on the time the divers can spend immersed, approximately one hour in six. However, it should be appreciated that dive duration is limited dramatically with increase in depth and at 50 metres a stay of only 10 minutes is permitted. The ascent must also include in water stops to facilitate the bodies decompression processes to proceed naturally.

Where conditions permit a deck decompression chamber (DDC) can be used to increase dive time by removing the need to carry out in water decompression stops. The diver returns to the surface as quickly as possible and enters the DDC which is then pressurised with air to a pressure equivalent to the water depth at the work site. Over a period of about an hour the pressure is gradually reduced to atmospheric, the diver inhaling oxygen to assist in the dispersal of dissolved bodily gases.

The main advantage of air diving is that it does not require the sophisticated equipment associated with saturation diving. Air diving plant may be containerised and located on the deck of a supply boat, or a fixed installation, thus saving on the considerable costs incurred when chartering a fully equipped diving support vessel (DSV).

## **2. SATURATION DIVING**

The main attraction of saturation diving is the increased productivity attainable from a diver due to the removal of restrictions on dive time and the need to decompress after each and every dive. Decompression takes place only on completion of the diving programme, or when the diver is due to go on leave. The disadvantage of saturation diving is the cost which can be considerable.

A diving programme commences with the transportation of the divers to the work site within the diving bell. At the site the divers enter the water through a hatch in the base of the bell having first donned helmets/masks and attached their umbilicals to the distribution manifold on the inside of the bell.

The umbilicals provide the diver with breathing gas and a supply of hot water to heat the diving suit. The divers spend approximately 6 to 8 hours at depth during which time the diving bell is used as a habitat where they can eat and rest. On completion of work the divers return to the bell, lock the hatch and are winched back to the diving support vessel (DSV).

Once on board the DSV the bell is locked onto the transfer hatch of the Deck Decompression Chamber (DDC) whilst the divers enter the DDC where they will remain until their next shift. Throughout the entire operation the divers remain under pressure which may be considerable, anything from 5 to 25 bar ( 75 to 375 psig ) depending on the saturation depth of the work site. Loss of pressure at any time would cause serious injury or death. This cycle may continue for a period of up to three weeks after which the divers commence decompression.

Decompression involves the gradual reduction of the pressure within the DDC to atmospheric to permit the natural dissipation of excess gases from the diver's body. It takes approximately one hour per metre ( 3.3 feet ) of water depth to effect safe decompression thus a saturation depth of 180 metres ( 600 feet ) requires a decompression interval of nearly a week.

## **3. EQUIPMENT**

A saturation diving system consists of a diving bell (submersible compression chamber - SCC) and a deck decompression chamber (DCC) and this combination of pressure chambers provides the means by which a diver's body is artificially maintained at a pressure equivalent to the work site for prolonged periods.

### **i) DIVING BELL (SCC)**

The diving bell provides transportation to and from the work site. It is secured to the diving support vessel (DSV) by a steel cable and an umbilical provides the occupants with breathing gas, heated water, electrical power and communication facilities.

The bell is housed within a substantial steel framework designed to provide protection against impact and a location for the ballast tanks and life support systems. An emergency release system permits

disconnection of the steel cable and umbilical should the divers encounter a situation which necessitates isolation from the DSV for instance a fire on the DSV or a fouled umbilical. The life support systems contain 96 hours of breathing gas and the facility to de-ballast the bell to permit a return to the surface.

ii) **DECK DECOMPRESSION CHAMBER (DDC)**

Deck decompression chambers are used for both air and saturation diving operations. The air diving DDC is a relatively simple affair consisting essentially of a cylindrical twin chamber pressure vessel. The saturation diving DDC is considerably larger and more lavishly equipped and provides an out of water home for up to 6 divers for the duration of the diving programme. It contains beds, toilets, showers, messing and recreational facilities (TV) and small air locks through which hot meals, laundry and medication can be passed to the divers. The occupants of the DDC are monitored 24 hours a day by the diving support crew and a particularly watchful eye is maintained during the decompression process.

iii) **DIVING SUITS**

Diving suits used for offshore inspection and repair programmes fall into two categories largely dictated by the degree of thermal protection required by the diver.

a. **Dry suit**

The dry suit consists of a watertight outer layer under which the diver wears thermal clothing to assist in the retention of body heat. In a cold water environment such as the North Sea the dry suit is only suitable for air dives of short duration beyond which a heated wet suit is preferred.

b. **Wet Suit**

The prolonged periods of submersion associated with saturation diving necessitate the wearing of a heated wet suit. Hot sea water supplied via the umbilical cable is circulated around the inside of the suit prior to exit at the divers extremities.

iv) **HELIOX**

Air consists primarily of oxygen and nitrogen and both these gases can prove injurious to the human body when ingested under the pressures associated with water depths greater than 50 metres (165 feet). The oxygen becomes toxic whilst the nitrogen leads to **nitrogen narcosis** or "drunkenness of the deep". Heliox, a specially formulated mixture of helium and oxygen provides a solution to both these problems because it permits the quantity of oxygen to be regulated to suit the body's respiratory needs at a particular depth. Helium like the nitrogen it replaces is an inert gas which fulfils no useful function in the respiratory process other than to bulk out the mixture and support the desired quantity of oxygen.

Whilst heliox may be used by divers who are not in saturation it is a gas primarily associated with saturation diving. The divers breathe the mixture throughout the saturation period, including the time spent in the DDC in between dives. In fact it is the period within the DDC in which another advantage of heliox emerges. The gas is much lighter than compressed air thus requiring less respiratory effort which ensures that the divers obtain restful sleep.

Heliox does have certain disadvantages which are the increase in heat transfer from the body which is considerable, the Donald Duck speech impediment created by the action of the gas on the vocal chords and the cost. The cost and adverse conductivity can be moderated by incorporating gas heating and recycling equipment whilst a voice synthesizer will minimise speech distortion.

## 4. VESSELS

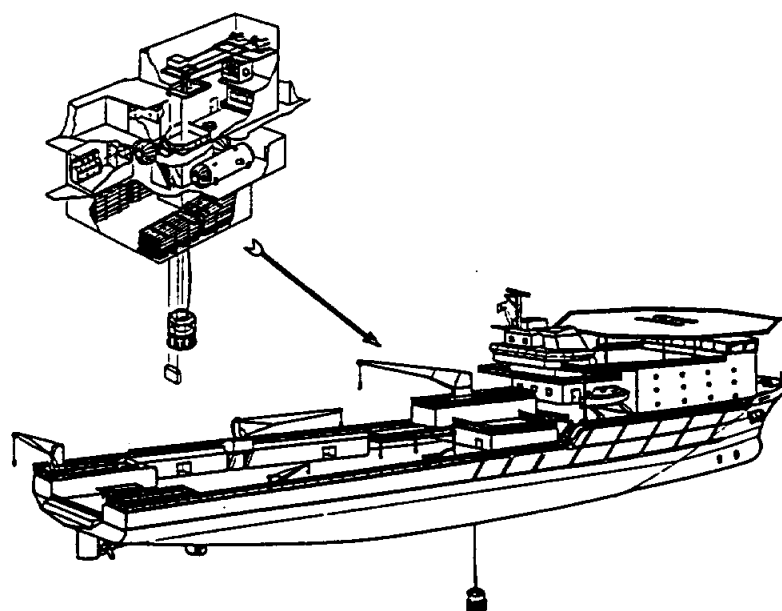
### i) DIVING SUPPORT VESSEL (DSV)

The primary function of the diving support vessel is to provide a stable platform from which the divers can carry out their duties. The complexity of the vessel will be determined by the type of diving operation for which it was designed, that is to say a saturation diving vessel will be considerably better equipped than one catering solely for air diving.

The DSV represents the diving company's single largest investment and the more divers the vessel can support, the more cost effective it becomes. The latest state of the art vessels employ up to 3 diving systems (3 deck decompression chambers and 2 diving bells) which can accommodate 18 divers working around the clock in water depths ranging from 20 to 450 metres (65 to 1,500 feet).

The charter rates for a modern fully equipped saturation diving support vessel are considerable (\$20,000 to \$50,000 a day) and to minimise lost time due to adverse weather conditions the vessels employ sophisticated active and passive hull stabilisation equipment and dynamic positioning (DP). The DP computer co-relates information pertaining to wind speed, wave height, currents and satellite reference positions and generates command signals for the control of the main propulsion and thruster units so that the vessel can remain on station and continue working in weather conditions approaching Beaufort 8 (gale force) without the need to deploy anchors. The effects of the weather are further negated by the "moonpool", a vertical shaft which runs through the centre of the ship and is open to the sea. The moonpool provides a sheltered haven for the launch and recovery of the diving bells and represents a considerable improvement on the traditional stern mounted "A" frame launching davit.

In an effort to increase the operational effectiveness of the DSV a number of vessels have been provided with well service equipment and can carry out intervention and workover programmes for the blossoming subsea market. This facility increases the likelihood of obtaining employment beyond the summer months after the routine underwater inspections have been completed.



DIVING SUPPORT VESSEL (DSV)



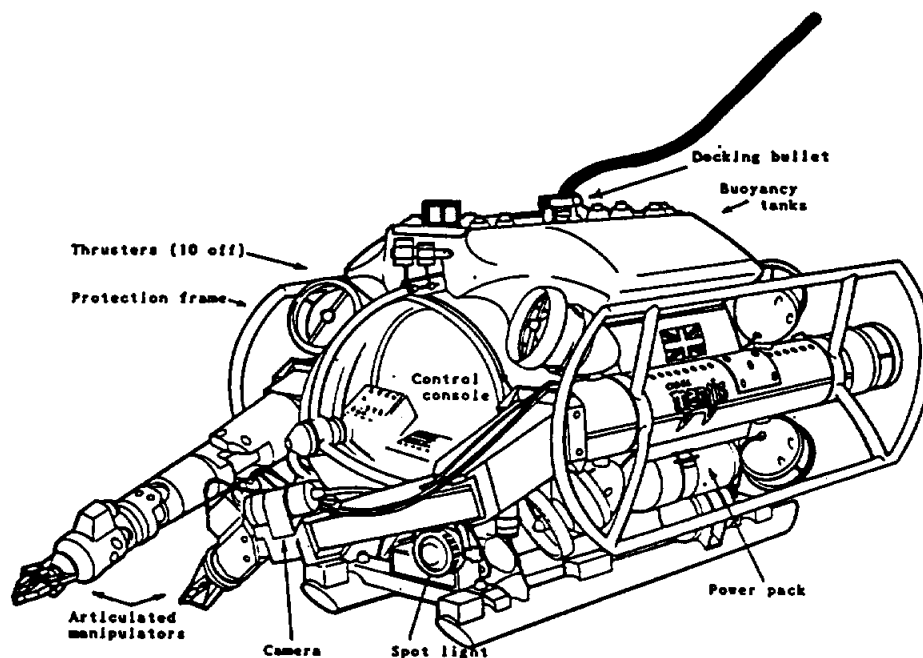
## ii) REMOTELY OPERATED VEHICLES (ROV)

A remotely operated vehicle (ROV) is essentially a mini-submarine that can be controlled from the deck of a ship or an offshore installation via an umbilical cable. The concept originated in the late 1970's and was developed to provide a cost effective alternative to the deep sea diver for routine inspection duties.

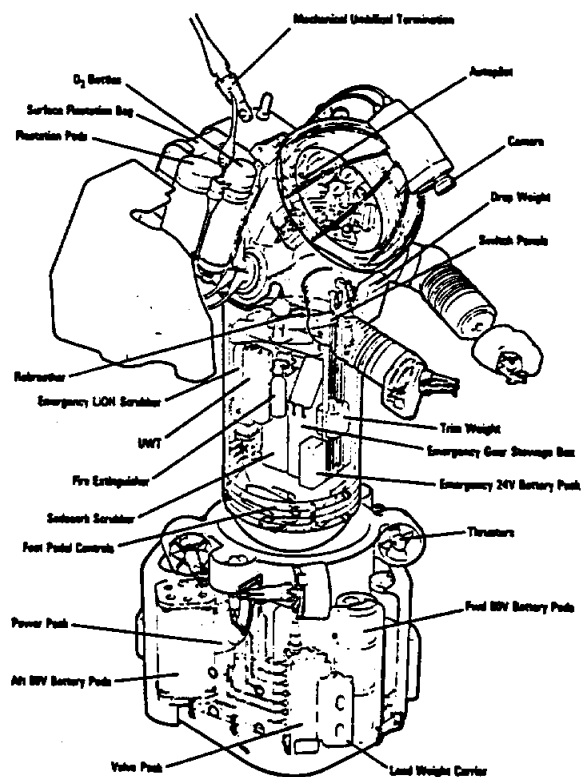
The external appearance of an ROV will depend largely on the type of work it is designed to carry out. The small inspection units often employ a spherical or cylindrical glass reinforced plastic (GRP) or acrylic hull to contain the electronic control and video equipment. The larger work units tend to use aluminium alloy pods to house delicate equipment. A steel frame provides protection against impact, and mounting points for ballast tanks, battery pods, manipulators (if fitted) and attachment of the umbilical cable. The complete assembly may weigh anything from 0.5 tonnes to 2.0 tonnes. Once in the water the ROV is manoeuvred by a number of motor driven ducted propellers which are electrically powered from self contained battery packs, or from an external source supplied via the umbilical cable. Buoyancy tanks assist in the maintenance of trim and water depth.

The first generation ROV's were designed purely to "eyeball" underwater activities, being driven around the work site whilst video pictures were relayed back to the command centre. They were, and still are used extensively to carry out the visual inspections on pipelines and jacket structures associated with the annual surveys. Further developments and the addition of articulated manipulators or "crabs claws" permit operations such as marine growth removal, ultrasonic thickness measurement and bolt tensioning to be carried out. However, it was the offshore industries acceptance of the advantages offered by the subsea wellhead that provided impetus to ROV development during the 1980's. The second generation ROV's were developed hand in hand with the new modular designed diverless subsea wellhead packages. These wellheads can be installed, maintained and repaired entirely by ROV. Ending the reliance on saturation divers also permits the exploitation of reserves located in water depths beyond the range of conventional diving techniques.

A discussion on ROV's would not be complete without a brief mention of manned atmospheric diving systems (ADS) such as the Osel Mantis and Slingsby Engineering's Spider. Occasionally referred to as microsubs they share many similarities with an ROV with the obvious exception of the increased hull capacity required to accommodate the pilot and life support systems. In fact the Mantis was constructed as a dual purpose vehicle and could be used in the manned and unmanned ROV mode. The main advantages of manned submersibles are the infinite levels of control afforded by an experienced pilot when compared to the remote operation of an ROV and the fact that they can be used at depths of up to 1,000 metres (3,300 feet), nearly twice the depth at which a saturation diver can operate. The hulls are maintained at a constant pressure of one atmosphere so there is no need for the pilot to undergo decompression after the dive. Unfortunately, these days manned submersibles tend to be restricted to military service, their use being discouraged by the leading oil companies on the grounds of safety, in spite of their excellent safety record.



**OSEL MANTIS Manned/unmanned ROV**  
(Hydrovision Ltd)



**SPIDER ADS SYSTEM**  
(Slingsby Engineering Ltd)

## **Part 2. UNDERWATER SURVEYS**

Specialised diving contractors are employed by the installation owners to carry out a planned inspection programme designed to detect any potential defects before they develop into major problems.

The scope of the planned inspection programme and its frequency must be agreed with the Certifying Authority and will normally include the following activities:

### **1. SPLASH ZONE VISUAL INSPECTION**

**Definition** - That part of the structure between the crest level of the 50 year (average) wave superimposed on the highest astronomical tide, and 3 metres below the lowest astronomical tide.

The splash zone can loosely be defined as that area of the jacket between the high and low water lines. It is a region which is particularly prone to corrosion and erosion because wave action makes maintenance of the protective paint coatings particularly difficult. It is also an area likely to sustain damage from impact with supply boats.

The splash zone survey will include an inspection of spider decks, boat moorings and landings, caisson clamps and risers.

### **2. SWIMAROUND SURVEY**

The object of the underwater swimaround is to detect any obvious signs of damage or distress such as missing structural members, failed joints, impact damage, loose or missing riser and caisson clamps.

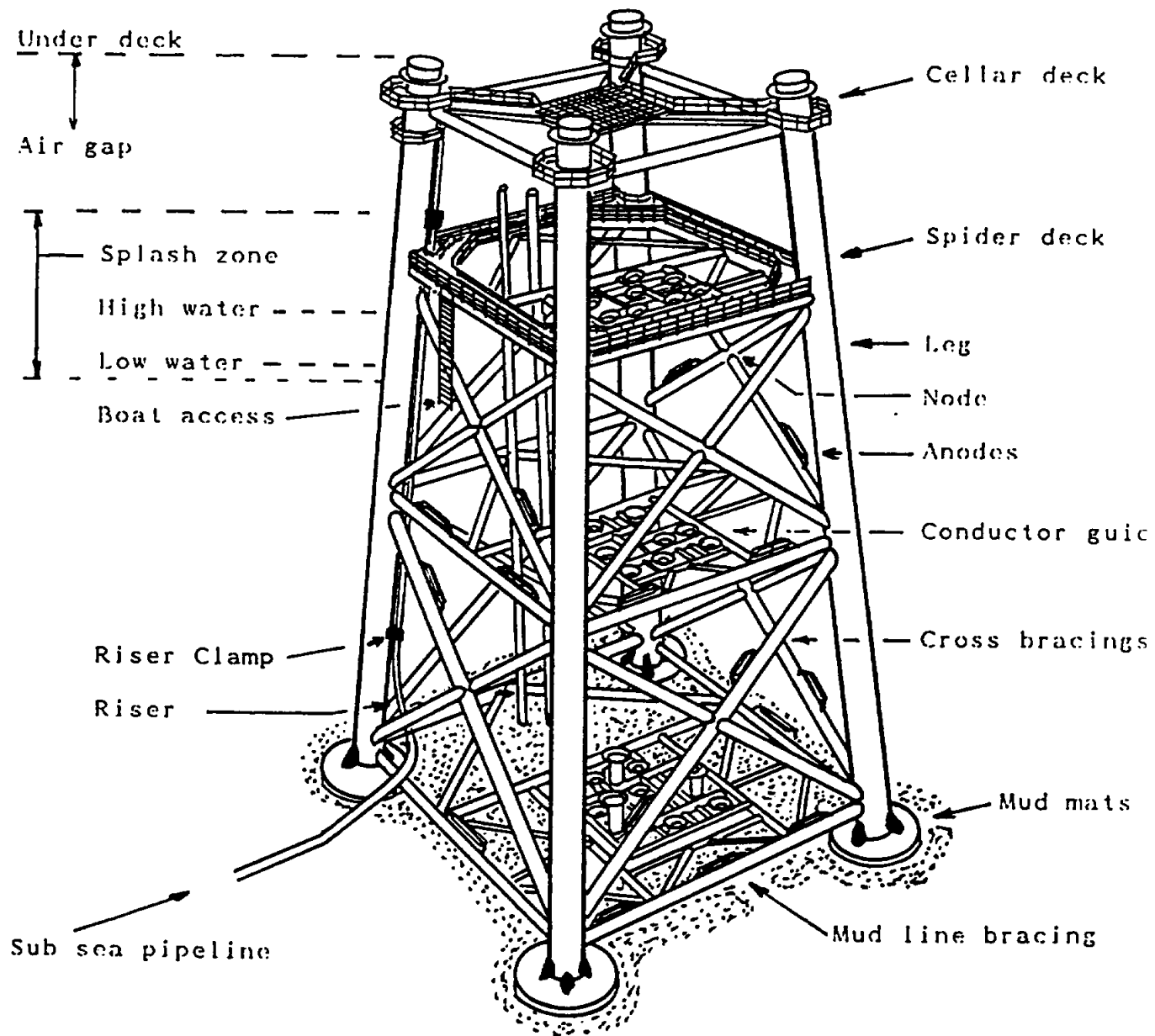
The sea bed will also be examined for 'debris' which may have fallen from the rig. This frequently includes gratings, scaffold poles and an assortment of objects dropped during construction projects.

### **3. NON-DESTRUCTIVE EXAMINATION**

An installation jacket consists of a considerable number of tubular members welded together. The point at which one tubular member is welded to another is referred to as a joint or node.

The planned inspection programme will identify those joints which, due to their design, are considered to be particularly highly stressed or to have low fatigue lives. A representative number of these joints will be thoroughly examined throughout the life of the jacket.

A thorough examination entails removing marine growth and scale by powered wire brush until bright metal is exposed. Should visual examination reveal a significant defect such as a crack, the suspect area will be subjected to a magnetic particle inspection. If the crack is confirmed some remedial grinding may be carried out. Should the defect remain after grinding a more extensive repair programme must be considered.



JACKET - COMPONENT PARTS

It should be noted that most jacket designs include a certain number of redundant structural members so discovery of a defect should not cause unnecessary concern.

### 4. FLOODED MEMBER SURVEY

This form of examination is relatively new to the industry but has gained considerable popularity due to the ease at which it can be carried out. Minimal cleaning of the structural member is required prior to attachment of an ultrasonic measuring device. The device can determine whether or not the member is full or partially full of water. The presence of water would indicate a crack or weld failure. If a flooded member is discovered it must be thoroughly examined using magnetic particle or ultrasonic inspection to determine the extent of the defect.

### 5. MARINE GROWTH MEASUREMENT

The additional weight imposed on an underwater structure by the presence of marine growth can be quite considerable. It must be carefully monitored if overloading of the structure is to be avoided.

Marine growth can be divided into two categories; hard and soft. The hard growth consists of crustacea such as mussels and the soft growth can be a combination of sea weeds and sponges. The soft weed is measured by wrapping a tape measure around the member to give a compressed growth reading.

A marine growth measurement of between 50mm to 100mm (2 to 4 inches) in depth can normally be tolerated before a cleaning programme is required. The thickness permitted will depend on the type of growth and the design of the structure.

### 6. SCOUR SURVEY

The sands of the sea bed have a tendency to drift in the same way as the sands of the desert. Scour is the term used to describe this subsea phenomenon. It is measured from a datum point, usually the first horizontal jacket bracing above the sea bed or mud line.

It is not uncommon to find a variation in sea bed levels of up to 4.5 metres (15 feet) between adjacent rig legs and if left unchecked the foundations will eventually become severely exposed and threaten the security of the installation.

Scour can also present problems with subsea pipelines by removal of the sea bed under the pipeline. The pipeline can be left suspended for considerable distances. This can induce excessive strains in the steel and leave the pipeline in a position where damage may be sustained from ships anchors or fisherman's nets.

The problem is normally rectified by dumping rocks, gravel or laying concrete mats to build up the sea bed and prevent further removal of sand. Another alternative is to pin nylon scour mats to the sea bed. These fibrous mats are constructed to encourage sand retention.

## **7. CATHODIC PROTECTION EXAMINATION**

The bulk of the underwater structure consists of bare steel and a cathodic protection system is employed to inhibit corrosion. This involves the attachment of zinc anodes at strategic positions on the jacket legs and bracings. Galvanic action promoted by the presence of sea water decomposes the anodes in preference to the steel structure.

Sufficient anodes (anything from 7 to 70 tons) are attached during construction of the jacket to last the life of the installation, normally 25 years. The underwater survey consists of monitoring anode condition and measurement of the potential difference generated. The potential should exceed 0.84 volts and can be measured directly using a Bathy corrometer.

There are two further surveys associated with monitoring the performance of the installations support structure. Whilst not part of the underwater survey they have been included in this chapter because they are structure and foundation related.

## **8. DIFFERENTIAL SETTLEMENT SURVEY**

Differential settlement readings provide an indication as to the continuing satisfactory performance of the jacket foundation piles.

The measurements may be obtained using an instrument similar to a building surveyors theodolite, or laser lines of sight directed at a fixed target on the shore line. In effect it entails measurement of the height of each corner of the installation relative to the other corners to see if any tilting has occurred.

Minor variations may be attributed to changes in deck loadings as may occur when any major items of equipment are added, or removed.

## **9. AIR GAP MEASUREMENT**

An offshore installation must be designed to resist the severest weather conditions. To withstand wave action there must be sufficient air gap or clearance under the lowest deck on the rig to accommodate what is known as a design extreme wave crest based on a 50 year return period, and still retain 1.5 metres (5 feet) of clearance gap. Occasional wave heights of 25 metres (85 feet) have been measured in the North Sea. The air gap must be monitored on a regular basis because it gives an indication of any settlement or sinkage that may have occurred due to reservoir depletion and sea bed subsidence.

Severe problems were encountered in the Norwegian Ekofisk field when several installations showed signs of sinking. The problem was addressed by cutting the jacket legs, jacking up the topside structures a distance of 6 metres and installing spacer spools.

## **Part 3. SUBSEA WELLS**

Subsea wells have been around for over 30 years and there are over 200 of them operating in the UK sector of the North Sea alone.

Basically subsea wells have two applications. They may be used in support of a fixed installation as an alternative to a satellite platform for recovering reserves located beyond the reach of the drill string, or used in conjunction with a floating production system (FPS). The combination of subsea wells and FPS provide a cost effective partnership for the recovery of oil from marginal fields, and are often the only means of developing very deep water fields.

Marginal fields may be categorised as those which contain reserves of less than 50 million barrels of recoverable oil or gas equivalent and their economic viability is ultimately dependant on how efficiently they can be developed. There are a considerable number of these marginal fields and extensive research has been carried out on the various options for the recovery of the oil and gas as the number of new, large field discoveries have diminished in mature provinces such as the North Sea.

### **1. SUBSEA WELLHEAD EQUIPMENT**

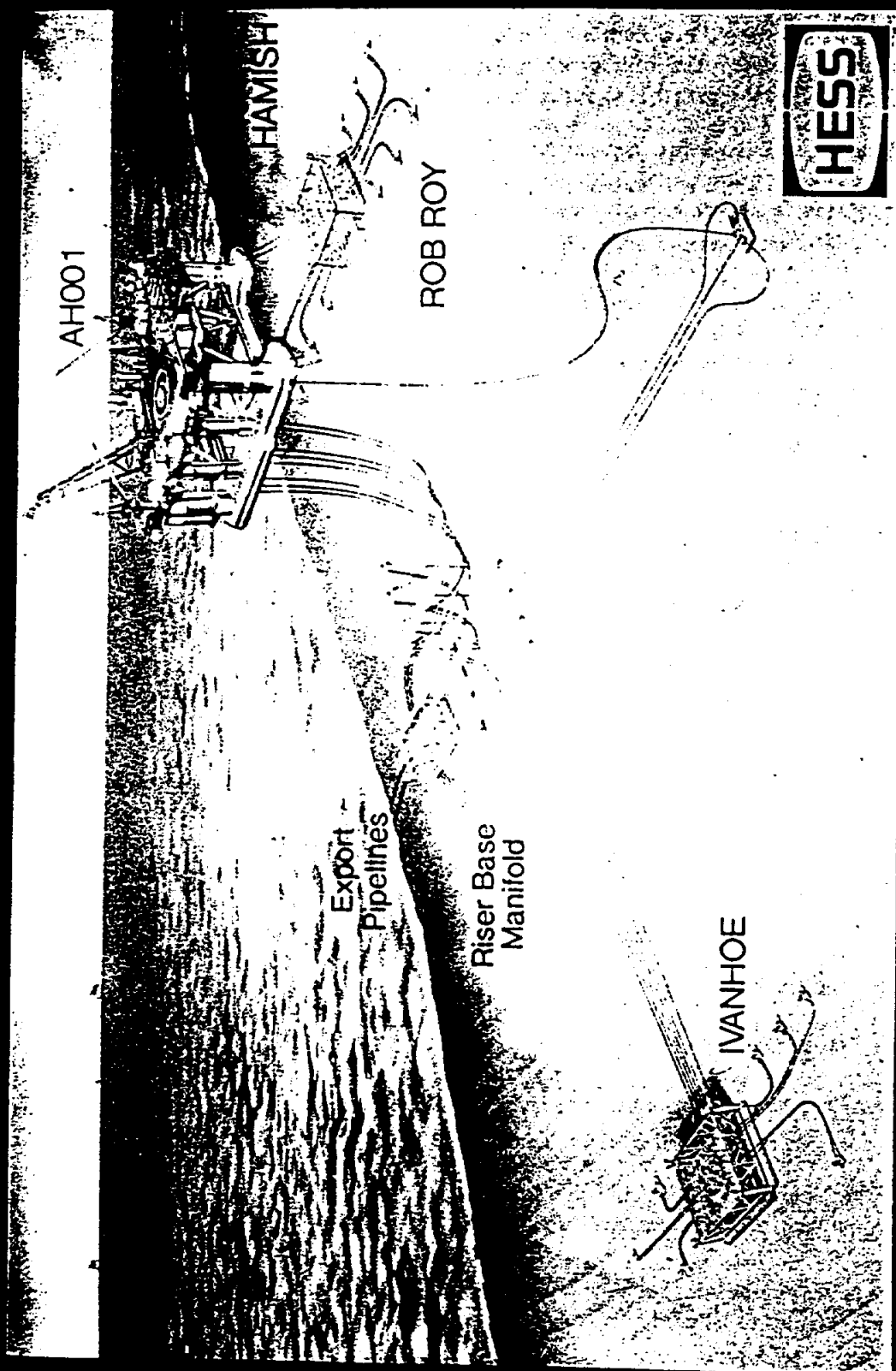
A subsea well consists essentially of a wellhead assembly and christmas tree that are basically identical in operation to their surface counterparts with the obvious exception of the detailed refinements required to ensure reliable operation whilst sitting on the sea bed surrounded by salt water and sand. They may be installed singly or in clusters on a template producing to a manifold which may be tied back to a floating production system (FPS), or a fixed installation.

Subsea wells may be drilled from a jack-up or semi-sub in a manner identical to conventional wells which terminate on a fixed platform. The most basic arrangement consists of a simple diver assisted christmas tree mounted over a mudline suspension system. However, as the need has arisen to produce oil from deeper waters more specialized subsea wellheads have been developed.

The latest state of the art wellheads and christmas trees are referred to as diverless and can be installed, maintained and repaired either by wire guided tools controlled from a surface support vessel, or by guidelineless (remote controlled) equipment. The wellhead sits on a guide base on the ocean floor which also provides location arrangements for the christmas tree. The christmas tree is bolted to an hydraulically activated collet connector prior to immersion, this facilitates attachment to the wellhead and flowline by remote control, all operations being monitored by an ROV (remotely operated vehicle). Reservoir products are transported back to the main installation via flexible flowlines and the christmas tree valves are operated by electrical or hydraulic control signals sent through an umbilical cable.

Ending the reliance on saturation divers has opened up vast reserves upto and beyond the thousand metre (3,280 feet) depth range that were previously thought to be unattainable. Whilst still referred to as new technology the diverless wellhead has proven extremely reliable and is being considered for use in more moderate water depths where the high initial cost would still appear to be justified when compared with the financial savings to be made on conventional diver intervention.

# IVANHOE, ROB ROY & HAMISH FIELDS SCHEMATIC



SUBSEA FIELD DEVELOPMENT



## 2. FUTURE DEVELOPMENTS

The use of subsea wells to recover reserves in the immediate vicinity of a host installation be it fixed or floating is a relatively straight forward operation. However, as the distance from the installation increases artificial means may be required to augment the natural reservoir pressure if the flow of hydrocarbons, and oil in particular is to continue. Whilst water injection is often used as a means of boosting reservoir pressure this option is only viable on relatively large oil fields. Gas lift recovery is however a practical alternative on marginal developments because of the inherent simplicity of the equipment. Unfortunately introducing additional gases into the produced oil further increases the already complicated task of transporting unstabilised hydrocarbon liquids over long distances.

The transportation of reservoir products, liquids or gases, is fraught with difficulties due to the volatile nature of the component parts of the hydrocarbon mixture, a problem exacerbated as pipeline length increases. The subject is more fully discussed in chapter 5. At any particular time the flow in an oil pipeline may be interrupted by "slugs" of vaporised gases whilst gas pipelines are likely to suffer from slugs of condensed liquids which drop out of the gas during pressure fluctuations. Large volumes of sand and water create additional problems, particularly as the reservoir ages.

The present horizontal range for deviation drilling from a fixed structure is about 8km (5 miles) whereas subsea wells may be located up to 15km (10 miles) distant from the mother platform. Extending the distance that wells may be located from the host installation has attracted considerable funding in recent years with the research proceeding along two quite different routes, namely subsea processing and multiphase pumping. The ultimate aim is to provide a reliable system for the exploitation of oil reserves up to 50km (30 miles) from the host facility.

### i) SEABED PROCESSING

The main advantage of seabed processing is that it ensures economic oil production over an extended period of time. It involves the separation of the gas from the liquids so that they may be transported back to the host installation through separate pipelines. This approach virtually eliminates the problems associated with the conveyance of unstabilised reservoir products over long distances and minimises the risk of hydrate formation. Hydrate formation can be further suppressed by the injection of a hydrate inhibitor such as methanol or glycol into the gas pipeline.

There are basically two types of seabed separation systems.

#### a. Seabed Process Facility

The seabed process facility is a relatively expansive collection of equipment using production separators in a similar fashion to those found on a conventional surface production installation. Single phase constant speed electrical pumps are employed to boost the pressure of the liquids as they exit the separator and provided that the pipeline is suitably sized to maintain the pressure above the bubble point the subsequent transportation should proceed smoothly.

#### b. Seabed Booster Station

The booster station is seen as an alternative to the seabed separation facility as a means of increasing flow from marginal fields, and deep water wells where reservoir pressure is insufficient to transport the hydrocarbons through the pipeline to the host facility.

It comprises a separator, electrically driven pump and compressor arranged in a single, vertical integrated unit mounted within a steel protection frame. As with the subsea process facility the liquids and gases are separated from one another prior to transportation. The provision of a gas compressor in addition to a centrifugal liquid pump increases the operational effectiveness of the system which is designed to permit production to commence until wellhead pressures drop to as low as 10 bar (150 psig).

The dimensions of such a booster station are impressive extending vertically upwards up to 15 metres (50 feet) from the seabed and weighing in excess of 100 tons, the entire package being designed for recovery by a surface support vessel via guideline wires. The accessibility of the equipment is seen as a major operational advantage.

## **ii) MULTIPHASE OPERATIONS**

A colossal amount of time and money has been expended on research into multiphase pumping and multiphase metering in recent years as the potential savings are enormous if reliable equipment can eventually be developed.

### **a. Multiphase Pumping**

The main advantage of multiphase pumping over equipment which relies on phase separation prior to pumping, is the fact that the reservoir products are transported through a single pipeline. This represents a considerable saving on costs when compared with installing both oil and gas pipelines over extended distances.

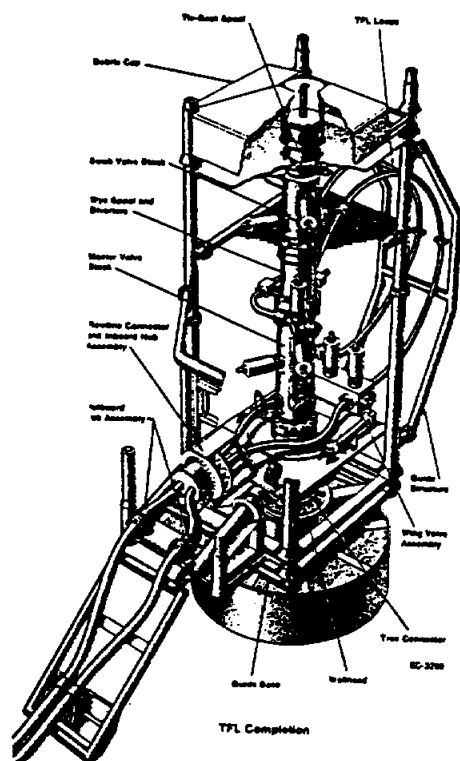
Multiphase pumps of the twin screw and helico-axial types have been developed and used successfully on land based applications. Their use offshore has been motivated by the desire to simplify equipment and further increase the potential of unmanned installations and subsea developments. Their use subsea is still at the experimental stage but the successful development of a multiphase pump would have far reaching effects within the industry.

### **b. Multiphase Metering**

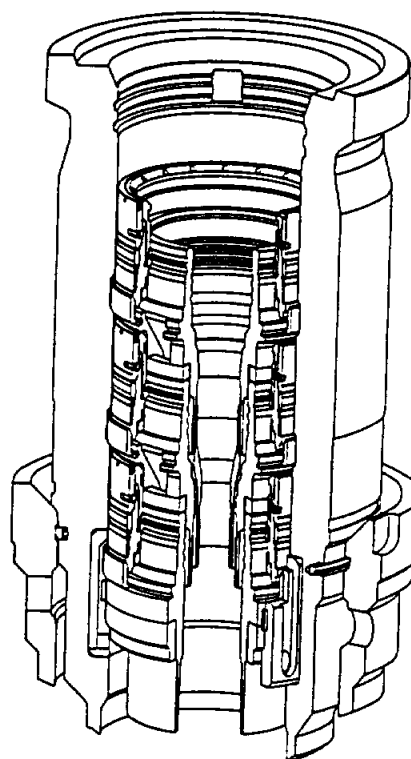
Various types of multiphase metering units are currently under development employing electronic sensors, or a combination of mechanical separators and electronic sensors to analyse and measure the flow of hydrocarbons in a pipeline. To determine the exact proportions of the various phases present is an extremely onerous but necessary task. Accurate measurement of the quantities of oil, gas, water and solids exiting a well is an essential prerequisite to successful reservoir management. At present it is a time consuming and labour intensive operation which involves the use of test separators and orifice meters on board the installation.

A limited degree of success has been achieved with multiphase metering during experimental field trials but a commercially viable unit is not yet available and a meter suitable for the additional rigours of subsea operation is not expected for several years.

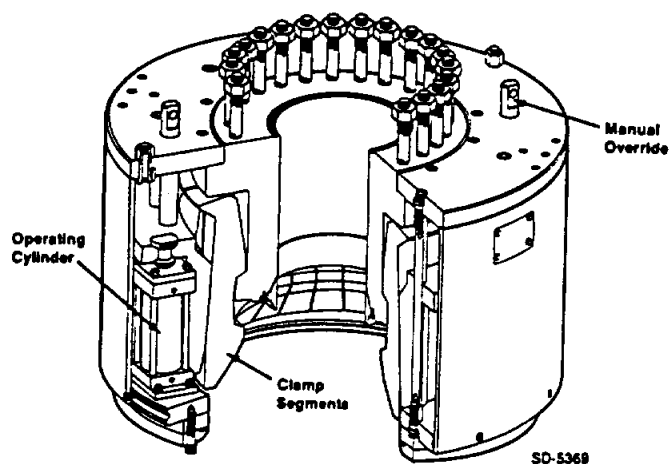
Of the 20 fields currently under development in the North Sea, 5 are considered marginal and will be exploited using subsea wells and floating production systems. Predictions indicate that a further 60 North Sea oil and gas fields could be developed using subsea completions in the next few years and it appears that the subsea industries of other oil producing countries are set to experience a similar pattern of growth.



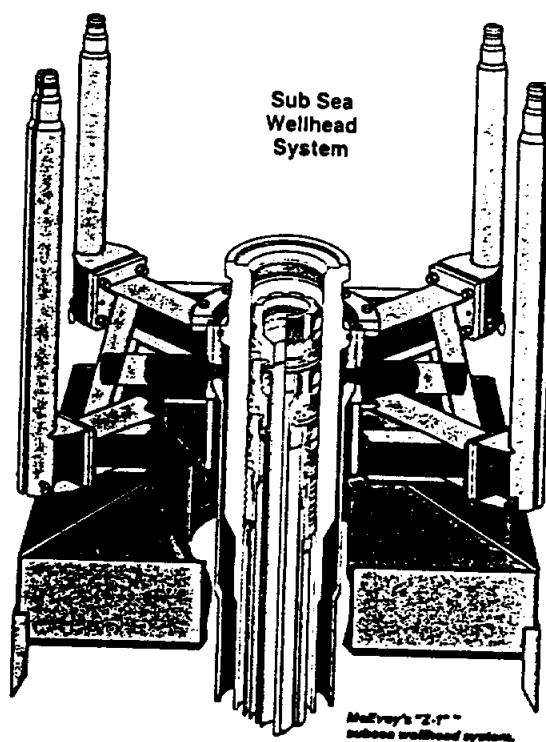
### Sub Sea Christmas Tree



### Sub Sea Wellhead



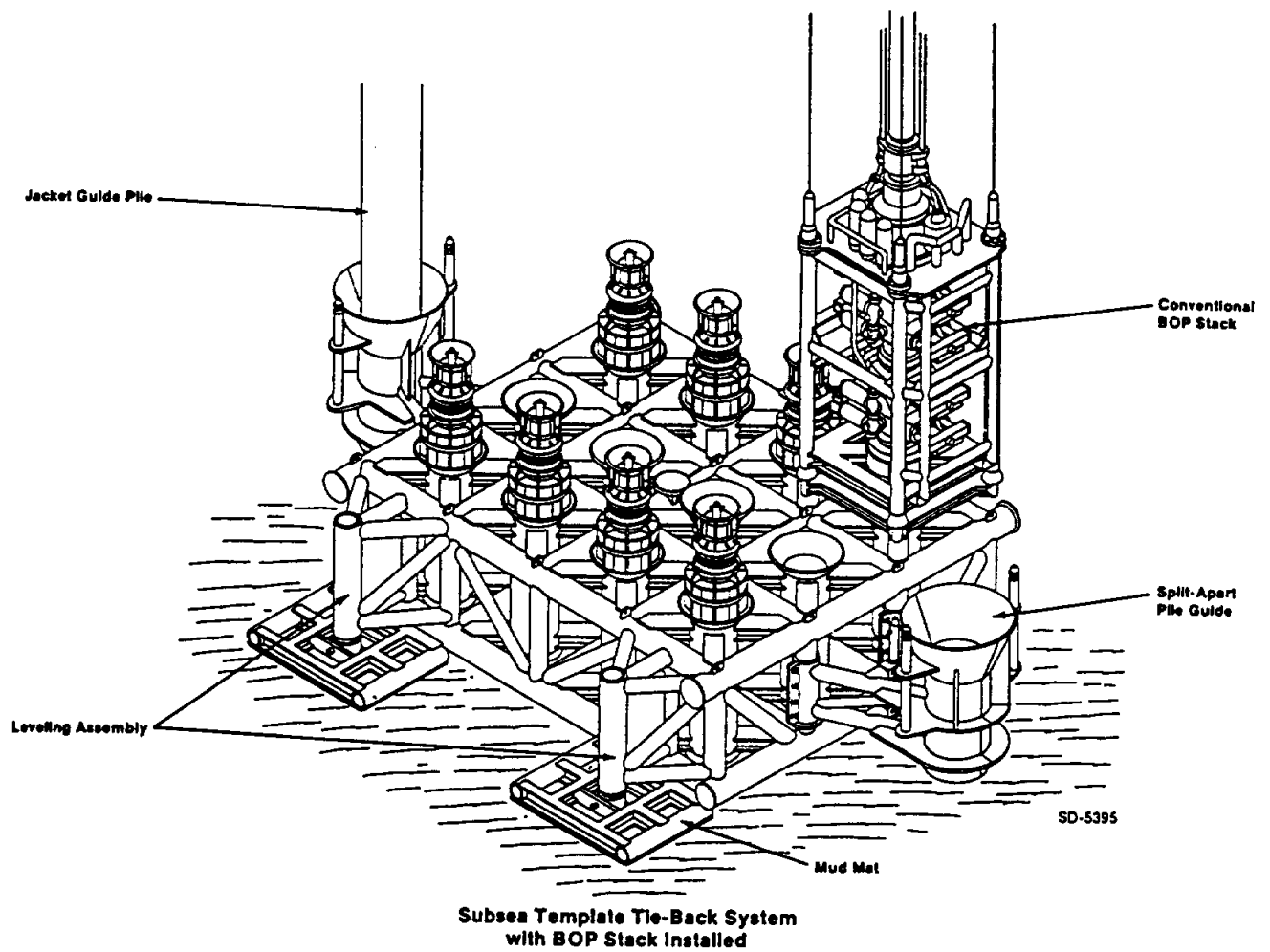
## Model 70 Hydraulically Operated Tree Connector



**McEvoy's "2.1" =  
subsonic wallhead system**

## SUBSEA WELLHEAD EQUIPMENT

(Reproduced with permission of Cooper Oil Tools, Houston, Texas)



**SUBSEA TEMPLATE**  
(Reproduced with permission of Cooper Oil Tools, Houston, Texas)

# Chapter Seven

## DRILLING

Of the many mysteries associated with the offshore industry, drilling is the most mysterious, cloaked in secrecy it is truly the blackest of the black arts.

Contrary to the wildcat gusher producing images created by the cinema, drilling a well is a highly organised operation which leaves very little to chance. In an effort to unlock some of the mysteries of the drill floor the following text has been divided into 6 parts and further sub-divided where required to assist in the explanation of what is a relatively involved subject.

### PART 1 – INTRODUCTION

1. The Formation of Oil and Gas
2. Exploration

### PART 2 – THE WELL

1. Well Construction
2. Cement Job

### PART 3 – EQUIPMENT

1. Drilling Derrick
2. Drill String
3. Drilling Mud

### PART 4 – OPERATIONS

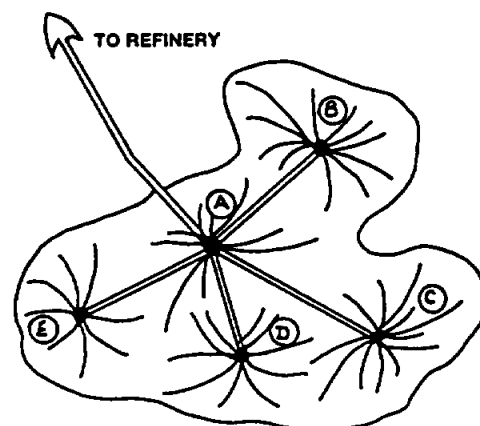
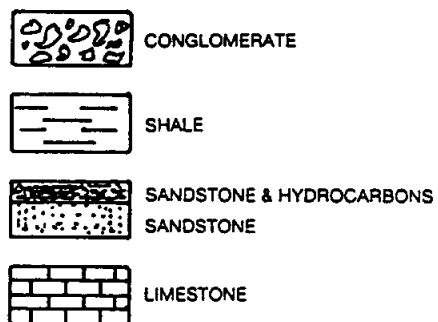
1. Drill Crew
2. Making Hole

### PART 5 – WELL CONTROL

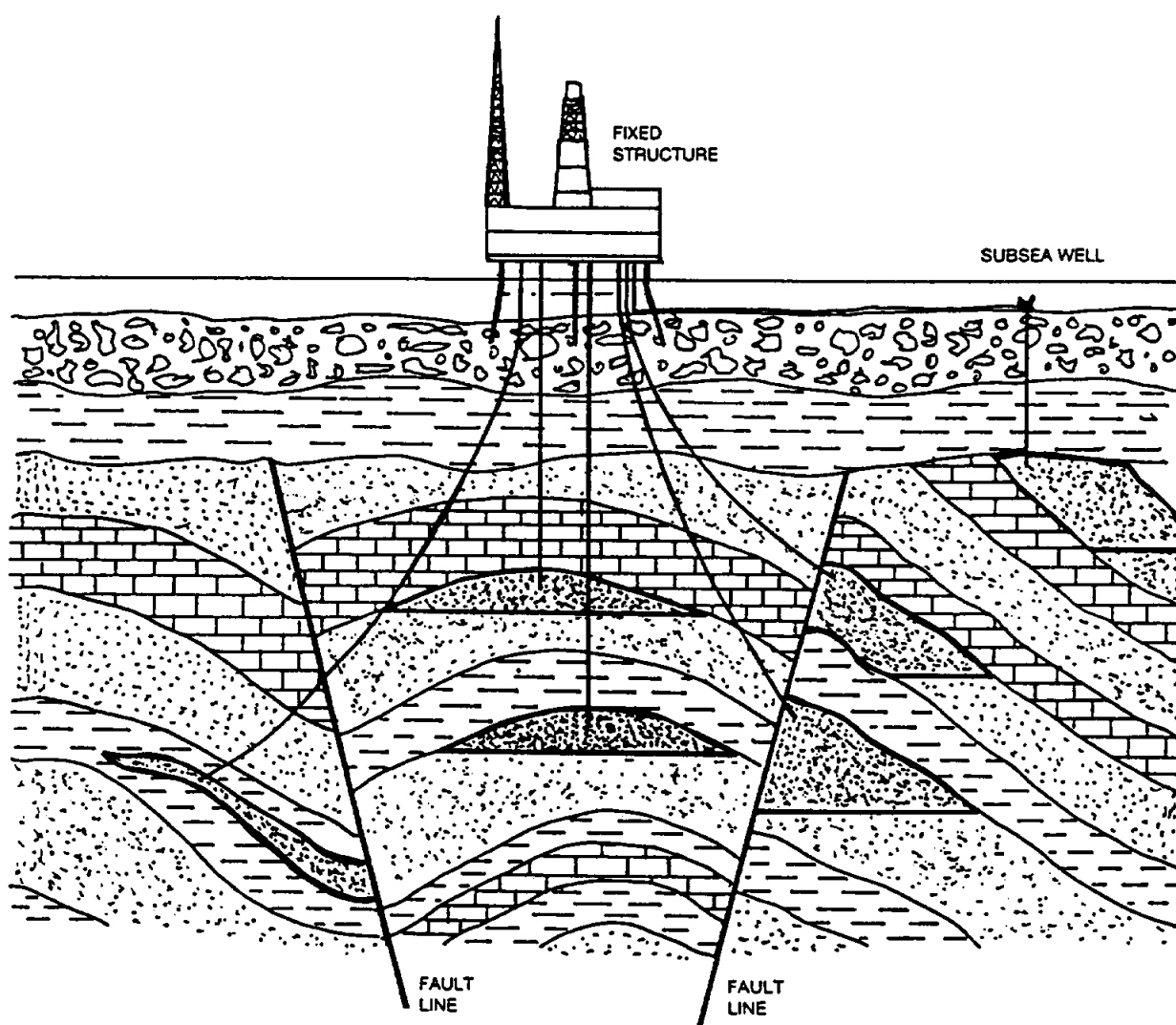
1. Diverter
2. Blowout Preventer (BOP)
3. BOP Operations

### PART 6 – ASSOCIATED PRACTICES

1. Floating Drill Ship Equipment
2. Directional Drilling



TYPICAL FIELD DEVELOPMENT  
PLAN USING 5 INSTALLATIONS



FORMATION OF OIL AND GAS  
OIL/GAS FIELD SCHEMATIC

## **Part 1. INTRODUCTION**

### **1. THE FORMATION OF OIL AND GAS**

It is thought that hydrocarbon deposits originate from the prehistoric remains of plants and animals. The most popular theory suggests that rivers transported sediment, flora and fauna into the sea where they mixed with plankton before being buried under considerable quantities of silt. Over a period of millions of years the organic matter decayed and decomposed under conditions of extreme pressure and heat into what we know today as hydrocarbon products. The deposits may be found in liquid, gaseous and solid (tar and oil shale) form and they all consist of the same base elements, hydrogen and carbon.

Whilst the exact mechanism which leads to the creation of oil and gas may not be fully understood, it is generally accepted that the hydrocarbon reservoirs were created by movement of the earth's crust. The various layers of rock, consisting primarily of the sedimentary sandstones, limestones, dolomites and shales were pushed into the equivalent of mountains and valleys. Where movement was excessive the layers slipped along geological fault lines thus creating conditions conducive to the formation of reservoirs.

A reservoir should not be thought of as some huge underground cavern containing oil or gas. The hydrocarbons actually exist within the structure of porous rocks in a condition analogous to a sponge full of water. The rock permits the passage of gas upwards and the drainage of oil downwards until an impermeable layer of rock, frequently shale, or a water table is encountered. These natural barriers prevent further migration of hydrocarbon products and encourage their accumulation, in effect the creation of a reservoir. An oil or gas field can cover several square miles and consists of several such geological traps or reservoirs, all of which must be tapped individually by bore holes or wells.

### **2. EXPLORATION**

Prior to the commencement of drilling activities, a Government licence must be obtained which will allocate an area or "block" of territorial waters designated as suitable for offshore exploration.

Having obtained an exploration block, the first operation entails enlisting the services of a survey vessel to carry out a seismic investigation of the rock formations located under the sea bed. A drilling programme will be prepared based on the geologists interpretation of the seismic survey results with exploration wells being drilled at locations where the rock formation indicates conditions conducive towards the accumulation of oil or gas.

The drilling of a wildcat or exploration test well is still the only foolproof means of confirming the existence of a hydrocarbon reservoir and a success rate of only 1 in 4 wells gives some indication as to the difficulties encountered in determining the existence of hydrocarbon deposits. It takes approximately 8 weeks and costs up to \$10,000,000 (\$60,000,000 in Arctic waters) to drill a test well so it doesn't pay to have too many failures.

On the occasions where drilling operations prove successful, a well test programme will be instigated to evaluate reservoir conditions and ascertain the exact nature of the hydrocarbon deposits. This entails flowing the well through a test facility located on the drilling vessel and the results will provide information as to the type of equipment that will eventually be required to produce the oil/gas and give an indication of any problems that may be encountered.

A successful well test programme will be followed by the drilling of a series of appraisal wells at locations considered by the geologists to represent the boundaries of the field. This will enable the physical dimensions of the field to be calculated and give an indication as to its development potential.

Where exploration surveys indicate that a field represents a commercially viable proposition, a permanent installation will be located at a position where it can reach the more favourable hydrocarbon bearing formations. Deviation drilling techniques permit the exploitation of reservoirs situated up to 6 km. horizontally distant from the rig whilst reserves located beyond the range of the drill string may be harnessed by subsea wells linked to the mother platform. Large fields may necessitate the installation of additional satellite platforms. The Leman gas field located off the coast of East Anglia supports more than 30 such platforms which are operated by Amoco and Shell.

Frequently fields are discovered which are considered to be marginal or borderline in terms of prospective profitability and often these must await improvements in the economic climate, or available technology before they can be considered for development. As an example, the advances in subsea equipment and drilling technology have recently permitted the exploitation of fields which were discovered 10 or 15 years previously and which were considered uneconomic at that time.

## **Part 2. THE WELL**

The majority of existing hydrocarbon reservoirs are located between the depths of 7,000 to 12,000 feet (2,100 to 3,500 metres) although discoveries of reserves located at depths of up to 15,000 feet (4,550 metres) are becoming more frequent. As one might imagine, if a hole is to be drilled to such a depth it must be drilled in several stages and reinforced to provide resistance against external pressure created by the rock formation. The process may be compared with the digging of a tunnel inasmuch as they both require additional support when passing through soft rock or sand. However, unlike a tunnel, the hole also requires reinforcing to withstand internal forces generated by the reservoir pressure.

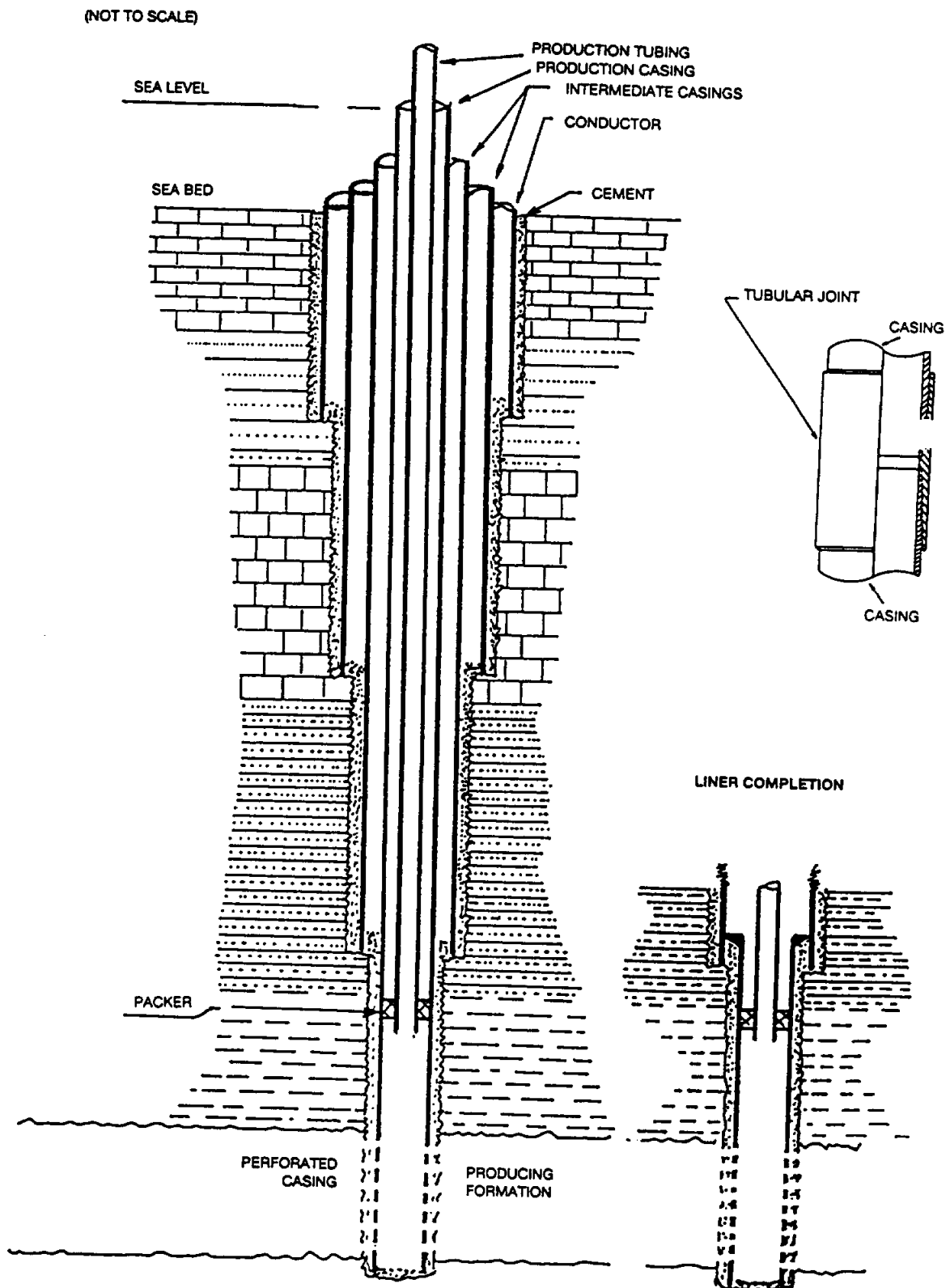
During the drilling operation a column of dense cutting fluid (drilling mud) stabilises the hole and prevents the ingress of loose formation products. On completion of each intermediate hole, permanent support is provided by the insertion of a steel pipe referred to as a casing string. The casing strings are assembled from 30 foot (9 metre) lengths of pipe known as joints which are screwed together as they are lowered into the hole. The casing string is then cemented into the rock formation prior to commencement of the next stage of drilling.

### **1. WELL CONSTRUCTION**

- i) The drilling operation commences with the installation of a large diameter steel pipe known as a conductor. Typically of 30 to 36 inch (0.75 to 0.91m) diameter the conductor provides the foundation for subsequent drilling operations and a support mechanism for the intermediate casing strings.

The conductor may be installed into a pre-drilled hole and secured with cement, or it may be piled into the sea bed. The latter approach involves driving the conductor to refusal, the depth at which it will go no further. The formation products are then drilled from the centre of the pipe and piling recommenced. This process is repeated until the conductor has been driven anything from 200 to 800 feet (60 to 240 metres) into the sea bed. A starting head is then fixed to the top of the conductor and a divester installed.





TYPICAL WELL CASING ARRANGEMENT

- ii) Drilling commences in earnest with the second hole which will be sunk to a depth of approximately 2,000 feet (600 metres). On completion of the hole, the drill string must be removed whilst the first intermediate casing string is lowered into the hole and cemented in place. A casing head spool is mounted above the starting head to support and seal the top of the casing and provide a temporary home for the BOP stack.
- iii) The number of subsequent holes drilled, their depth and diameter will be governed by the type of rock formation and the overall depth of the hydrocarbon reservoir. Broadly speaking the drill bit will be reduced in diameter every 3,000 to 6,000 feet (900 to 1,800 metres) and the hole "cased off" (casing inserted). However, on occasions hole collapse or loss of drilling mud into the formation will necessitate suspension of the drilling programme and premature installation of the intermediate casing string. Having thus reinforced the hole, drilling may be resumed using a smaller diameter drill bit.
- iv) Eventually the drill bit enters the hydrocarbon bearing formation. When the hole has been drilled to the required depth the drill string must be carefully removed to permit completion of the well, the hydrostatic head of drilling mud preventing hydrocarbon products entering the hole. Completion of the well involves the insertion of the production casing string which may be terminated using any one of three configurations.

**a) Casing completion**

As shown in the main sketch, the production casing string is run to the bottom of the hole and cemented in an identical manner to the preceding casing strings.

**b) Liner completion**

As shown in the detail sketch, the casing or liner extends from the base of the previous casing and is not returned to the surface. It is installed on the end of a drill string attachment and secured by a packing device prior to cementing. Liner completions are used extensively and permit a considerable saving on casing, in excess of 3,650 metres (12,000 feet) in a typical North Sea well.

**c) Open hole completion**

The open hole completion refers to the practice of leaving the hole uncased in the vicinity of the hydrocarbon formation, the casing or liner being terminated at the top of the hole.

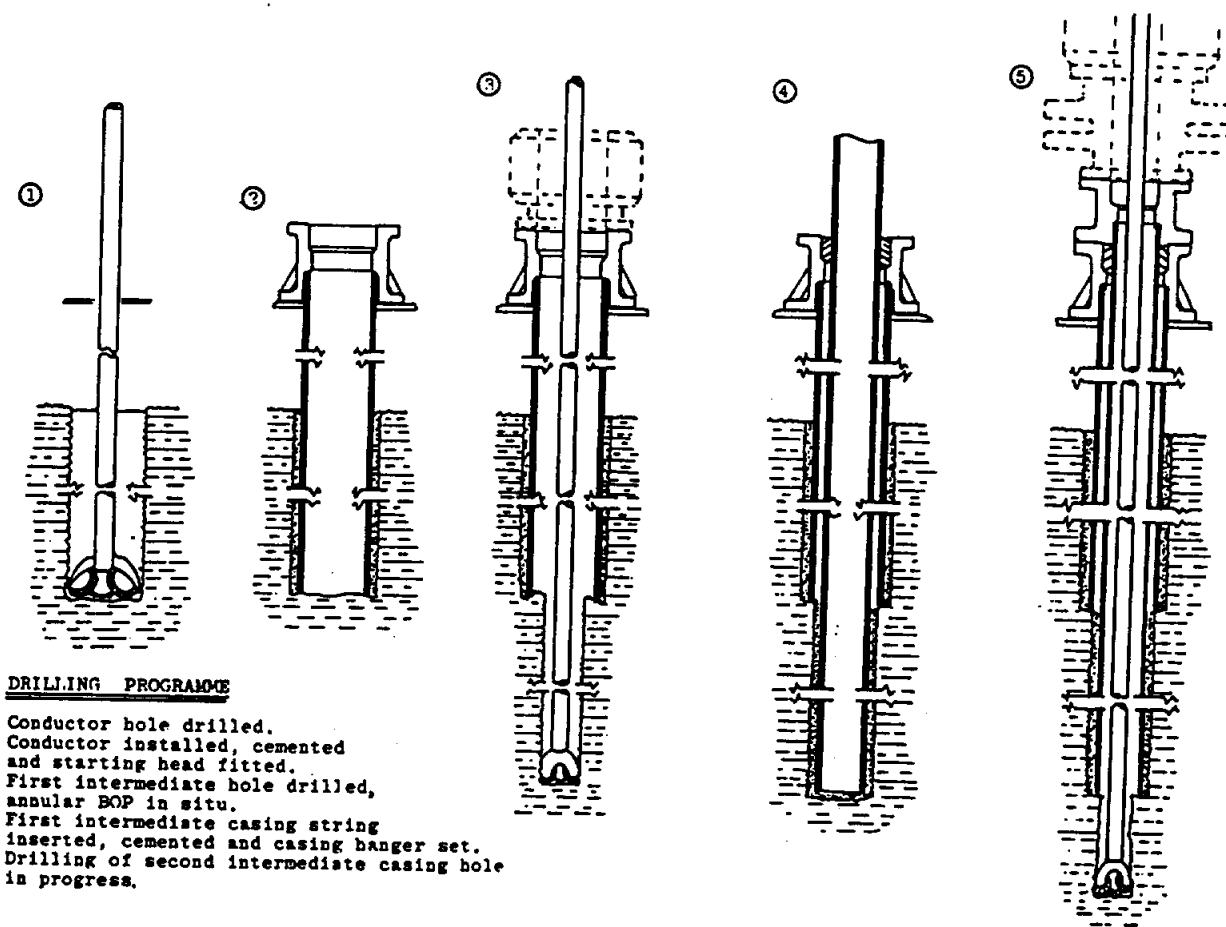
- v) The penultimate operation entails installation of the production tubing and christmas tree in preparation for perforation and the commencement of production.

The production tubing is essentially a small diameter casing string which is suspended from a tubing hanger located under the christmas tree and held within the lower reaches of the preceding casing by a packing device. This arrangement facilitates removal of the tubing should well modification work be required at a later date. The production tubing contains a number of machined recesses or nipples designed to accommodate the mudline safety valve, and steel plugs that are used to isolate the well during repair and maintenance operations.

With the exception of the casing located below the packer, the production tubing is the only component within the well which receives direct exposure to the reservoir pressure and it is through the production tubing that the oil and gas will flow to the surface. Once the christmas tree has been nippedled up (bolted up) to the production tubing hanger and hydrostatically tested, the perforation operation can commence.

- vi) It should be remembered that prior to perforation, the well bore is isolated from the hydrocarbon bearing formation by the casing string and is still full of conditioning or well preservation fluid (normally brine or diesel oil). Perforation involves the puncturing of the final length of casing string in the vicinity of the hydrocarbon bearing formation, a distance which can extend over several hundred feet. It is achieved by lowering shaped explosive charges into the well on a wireline tool string and detonating them by remote control. The charges blast through the steel casing and cement and permit the passage of reservoir products into the well bore.

Initially entry of the oil or gas into the production tubing is prevented by the hydrostatic head of preservation fluid. The hydrocarbon flow can be initiated and the well brought "on line" with coil tubing, or a blanket gas.



## DRILLING PROGRAMME

1. Conductor hole drilled.
2. Conductor installed, cemented and starting head fitted.
3. First intermediate hole drilled, annular BOP in situ.
4. First intermediate casing string inserted, cemented and casing hanger set.
5. Drilling of second intermediate casing hole in progress.

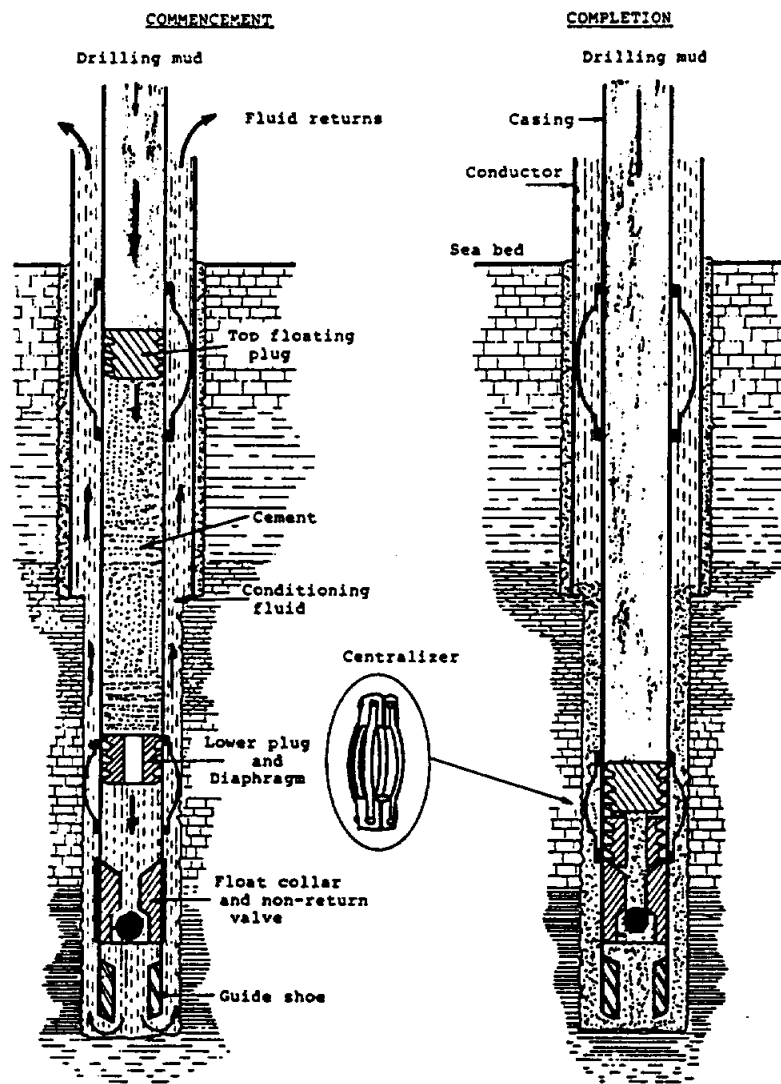
## DRILLING PROGRAMME

a) **Coil tubing**

Coil tubing involves the insertion of a small diameter (1" or 25.4 mm) steel tube through the christmas tree and down to the base of the well. High pressure nitrogen gas admitted through the tube helps displace the preservation fluid so that the flow of hydrocarbons can commence.

b) **Blanket gas**

Prior to perforation, the hydrostatic head of preservation fluid is reduced to a value less than the reservoir pressure and a charge of nitrogen gas is then admitted to the well bore. The combined pressure created by the brine and nitrogen exceed reservoir pressure and provide the necessary safety barrier. On completion of perforation, the nitrogen gas can be vented to atmosphere and the reduction in pressure will permit the reservoir products to displace the remaining column of brine and let flow commence.



**THE CEMENT JOB**

Having dealt with the drilling of the hole and the installation of the intermediate casing strings into the rock formation, we should consider how the casings and production tubing are secured on the production platform. The securing system is referred to as the wellhead and has been dealt with in chapter 8.

## 2. THE CEMENT JOB

As explained in the preceding section, a well is drilled in stages all of which are individually lined with a steel casing string that is secured into the formation by cement. Cementing the casing strings produces an extremely rigid assembly and provides protection against corrosion products released by the formation.

The sketch opposite has been prepared to assist in the explanation of the cementing process or "cement job".

On completion of each stage of drilling and prior to the introduction of the casing string the hole may be "conditioned". Conditioning involves the replacement of the drilling mud with a conditioning fluid, frequently a brine solution suitably weighted to prevent the ingress of hydrocarbons into the hole, should they occur.

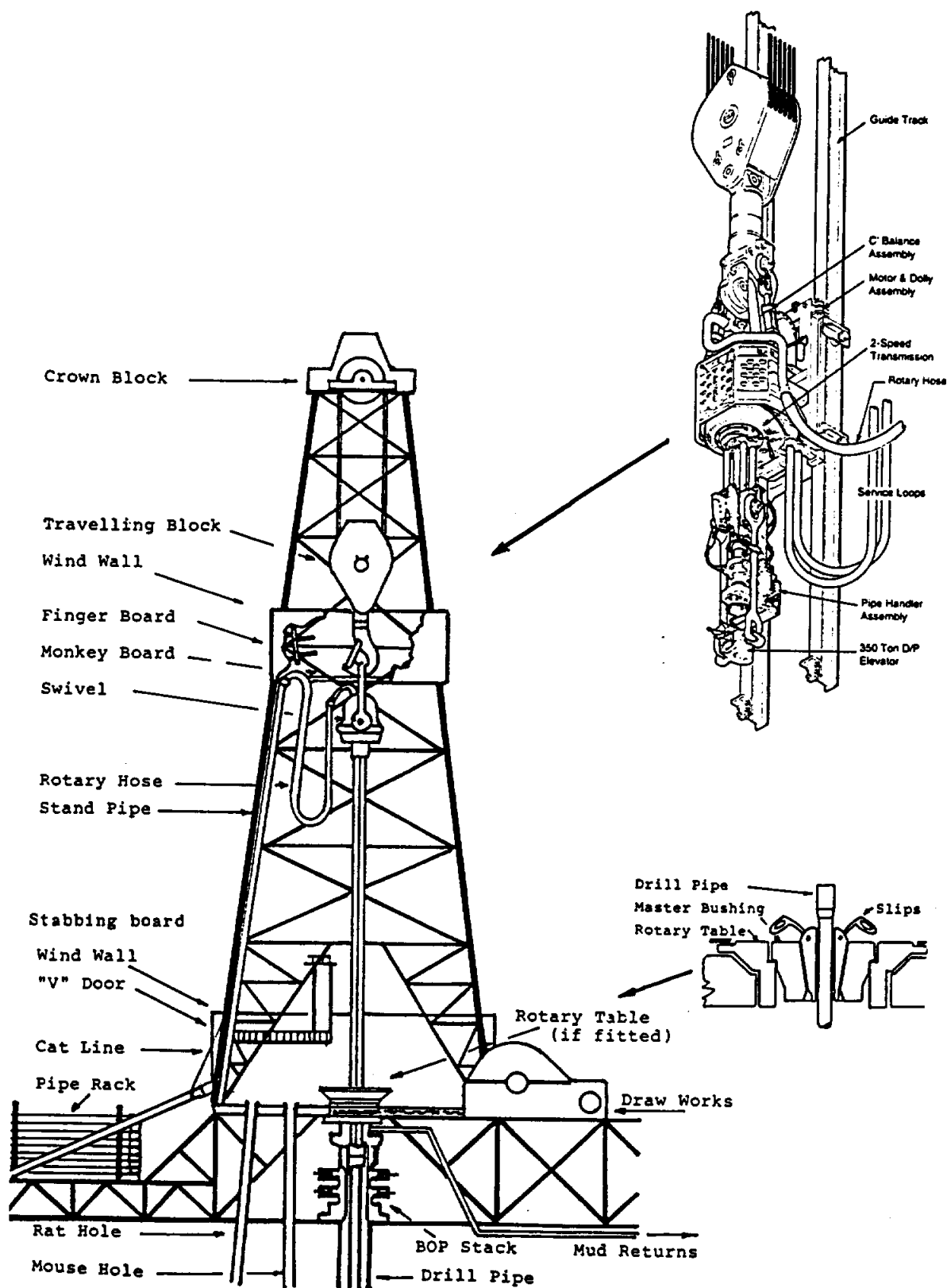
The conditioning process removes any "oiliness" left by the drilling mud and improves the chances of obtaining a secure bond between cement, casing and hole. With the hole suitably conditioned the installation of the casing string can commence.

The first section of each casing string lowered into the hole is fitted with an internal guide shoe and float collar which contains a non-return valve. Subsequent casings are fitted with external sprung steel centralizers at regular intervals to ensure that they locate centrally within the hole and provide an unrestricted channel for the passage of cement. The cementing process can proceed as soon as the final length of casing enters the hole.

The first operation entails insertion of a floating plug into the casing that will provide a barrier between the preservation fluid and the cement. A measured quantity of cement is then pumped into the casing, the volume calculated from the size of the hole and the external diameter of the casing string. A second floating plug is then installed above the cement and the drilling mud system re-connected.

The casing now resembles a giant syringe and as pressure is applied to the drilling mud, the column of cement moves slowly down the inside of the casing until it reaches the non-return valve located in the float collar at the base of the casing. When the bottom plug contacts the non-return valve, the diaphragm within the plug ruptures permitting the passage of cement through the plug and into the space created by the drilled hole and the external surface of the casing. Drilling mud pressure is maintained until a rapid increase in resistance indicates that the top plug has contacted the bottom plug and the cementing process is complete.

The cement takes from 6 to 24 hours to cure depending on the downhole temperature and during this period it is prevented from flowing back into the casing by the non-return valve in the float collar.



DRILLING DERRICK

## Part 3. EQUIPMENT

Having outlined the basic process by which a well is drilled and completed we can now discuss in greater detail the major items of equipment required to perform successful drilling operations from a sea bed supported structure such as a jack-up or a fixed installation.

The main components are:-

1. Drilling Derrick.
2. Drill String.
3. Drilling Mud System.

### 1. DRILLING DERRICK

The most prominent feature of an offshore installation is the drilling derrick. It consists of a steel lattice tower approximately 50 metres (168 feet) in height which supports the Crown Block and provides temporary storage facilities for drill pipe stands.

The sketch shows the main component parts of the derrick.

#### i) CROWN BLOCK

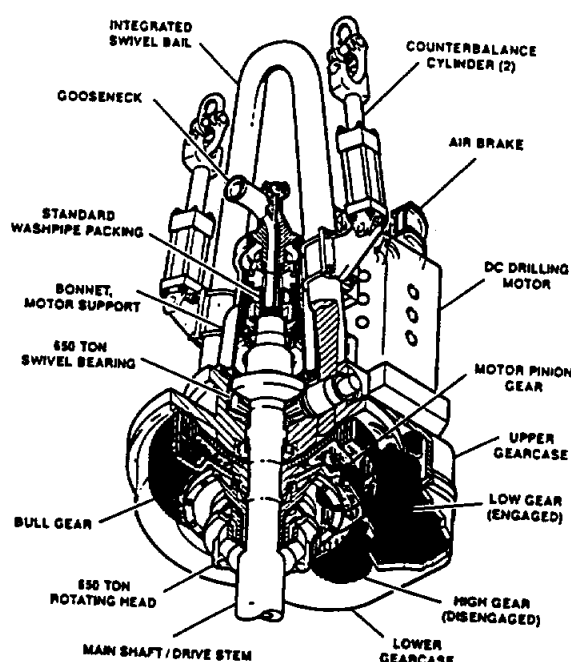
The stationary sheaves mounted at the top of the derrick over which the wire ropes attached to the travelling block pass.

#### ii) TRAVELLING BLOCK

The large heavy duty, multi-sheave lifting block which is used primarily to support the weight of the drill string during drilling operations and to hoist drill pipe and casing into and out of the hole.

#### iii) TOP DRIVE

The top drive assembly has all but superseded the rotary table as the means by which rotary motion is imparted to the drill string. It consists of a large electrically or hydraulically powered motor which is suspended from the travelling block and connected directly to the drill string.



**TDS-4S TOP DRIVE POWER TRAIN  
(Dual Speed)**

(Reproduced with permission of  
Varco BJ, Orange, California)

**iv) MONKEY AND FINGER BOARDS**

The small platform located in the top half of the drilling derrick from where the monkey, or derrick man, can manoeuvre pipe stands into and out of the finger board during a trip.

The finger board resembles a large peg board and is located alongside the monkey board. The finger board provides a location for the drill pipe stands.

**v) STABBING BOARD**

Small self-elevating platform from which casing can be guided into the well.

**vi) DRAW WORKS**

The collective name given to the power control centre on the drill floor. It consists essentially of a large hydraulically or electrically powered winch which provides the motive power to operate the travelling block and the rotary table (if fitted).

**vii) ROTARY TABLE**

Where fitted, the rotary table consists of a large casting located centrally within the drill floor and it is used to impart rotary motion to the drill string, being chain driven from the draw works. It contains removable bushings which permit the passage of the drill string components whilst also providing a drive mechanism for the rotation of the square section Kelly.

**viii) DOGHOUSE**

Tin hut or shed located at the side of the drill floor and used as a shelter by the drill crew.

**ix) MOUSEHOLE**

A pipe let into the drill floor in which a new section of drill pipe is inserted prior to its connection to the Kelly and subsequent inclusion in the drill string.

**x) RAT HOLE**

A pipe let into the drill floor to accommodate the kelly during the making of a trip.

**xi) PIPE RACK**

Area of deck in front of the drilling derrick where drill pipe and casing are stored prior to use.

**xii) PIPE DRAW (or ramp)**

Ramp leading from the pipe rack to the drill floor over which drill pipe and casing are dragged by the catline.

**xiii) "V" DOOR**

The V shaped opening in the windwall between the pipe rack and the drill floor.



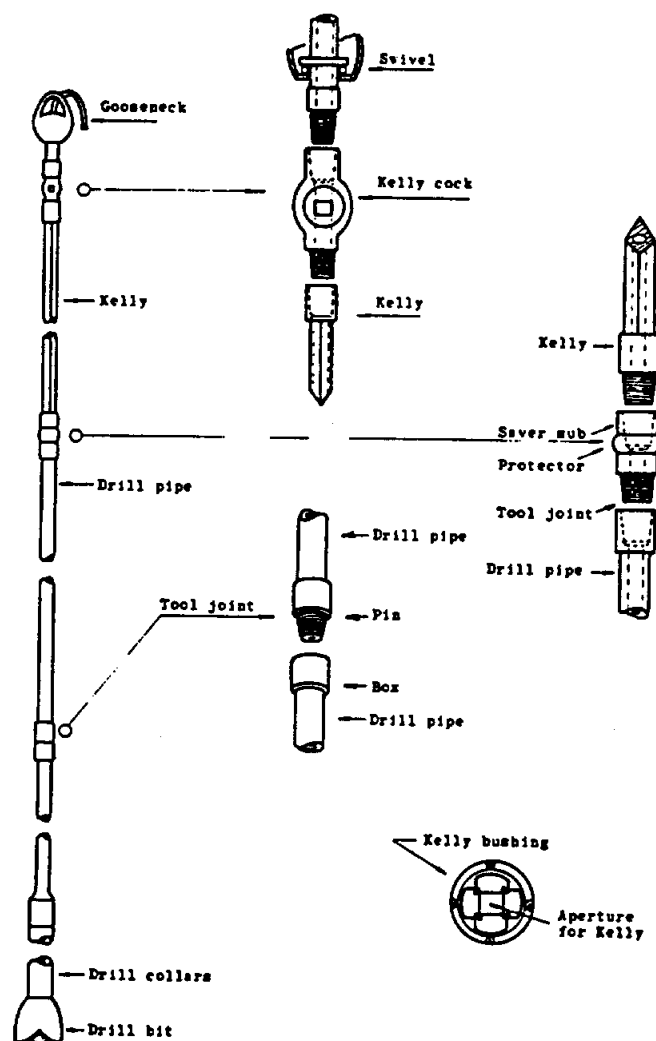
xiv) CAT LINE (or Tugger)

Small winch used to transport drill pipe and casing from pipe rack to drill floor.

## 2. THE DRILL STRING

The drill string is the collective name which describes the assembly of components used to drill a hole. They are:-

- i. Drill bit
- ii. Drill collars
- iii. Drill pipe
- iv. Kelly
- v. Saver-Sub assembly
- vi. Swivel



THE DRILL STRING

**i) DRILL BIT**

The drill bit, roller cone or rock bit consists of three rotating cones which are fitted with hardened steel, carbide tipped or diamond edged teeth. The choice of tooth material will depend on the type of rock formation through which the drill bit must pass.

**ii) DRILL COLLARS**

The drill collars are heavy, thick walled pipe joints which connect the drill bit to the drill pipe. Anything from 2 to 30 collars may be used to provide concentrated weight in the vicinity of the drill bit to assist in the rock breaking process. The collars also provide rigidity to the drill string which prevents the bit from wandering from the vertical during drilling operations.

**iii) DRILL PIPE**

Drill pipe is supplied in 30 foot (9 metre) lengths and consists of 3½ or 5 inch diameter heavy wall pipe with male and female couplings welded to each end. The couplings are referred to as pins (male) or boxes (female) and permit assembly and disassembly of the drill pipe during drilling operations.

**ii) KELLY (required only for rotary table drive)**

The Kelly consists of a long, hollow, square section forging which screws into the top section of drill pipe. It is driven by the rotary table and provides the drill pipe with both rotational movement and drilling mud.

**v) SAVER-SUB ASSEMBLY**

The saver-sub assembly consists of a simple male/female threaded spacer designed to protect the Kelly or power take off shaft threads from damage during the repeated make-up or break-out of the sections of drill pipe.

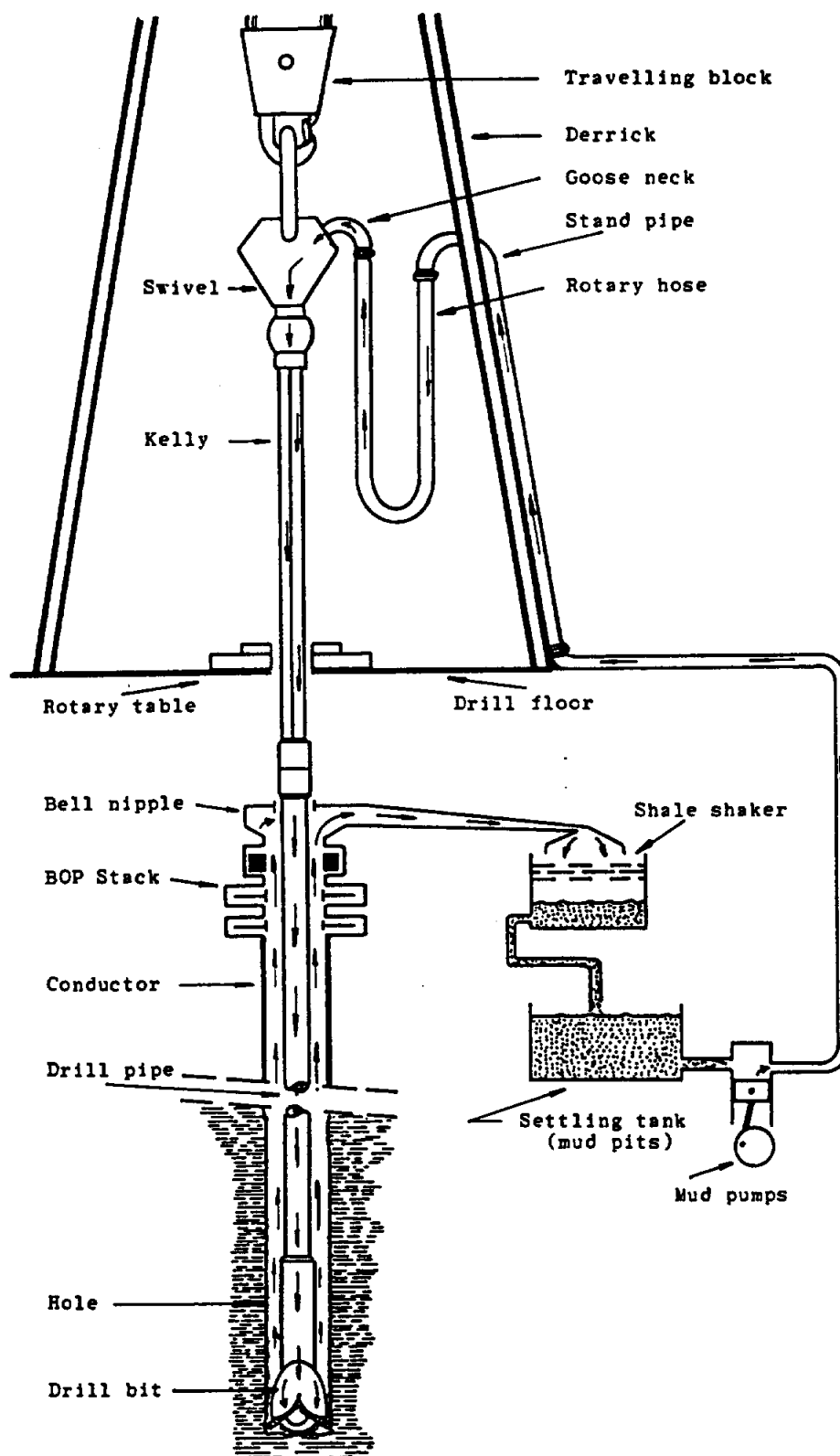
**vi) SWIVEL**

The swivel permits the drill string to revolve freely whilst suspended from the travelling block and provides for the passage of drilling mud. The mud is supplied via the rotary hoses which are connected to the goose neck on the swivel.

### **3. DRILLING MUD**

Drilling fluid or "mud" as it is universally referred to is the life blood of the drilling operation. It lubricates the drill bit, removes drilling debris, stabilises the hole and provides the principal safety barrier against the ingress of hydrocarbons into the well bore.

In actual fact, drilling mud is quite a sophisticated fluid consisting essentially of bentonite, colloidal clay dissolved in either water or fuel oil. Baryte (Barium Sulphate) is added as a weighting medium to permit variation of the specific gravity and the only resemblance the final product has to "mud" is its consistency and in the dreadful mess it creates.



DRILLING MUD SYSTEM  
(rotary table)

Considerable care must be exercised in the preparation of the drilling mud to ensure that drilling operations progress in a smooth and safe manner. The density of the mud must be continuously monitored and adjusted to ensure that the hydrostatic head it creates within the hole is always greater than the pressure likely to be encountered should the drill bit strike an unexpected pocket of oil or gas. The formation pressure is primarily a function of hole depth and can be estimated with a fair degree of accuracy. An adequate head of mud will prevent a blow out, that is a blow back of hydrocarbons into the hole and up to the rig floor. However, an excess of mud pressure must be avoided, particularly when drilling through soft formations where the mud will simply force its way into the structure of the rock and circulation will be lost. When this happens drilling must be suspended and a casing string inserted to reinforce the hole.

The majority of drilling operations are performed using a water based mud which is both cheaper and kinder on the environment than the oil based varieties. However, oil based muds are preferred for drilling operations through water sensitive shale formations and for the drilling of highly deviated wells which benefit from the additional hole stability provided by the denser mud as it cakes the well bore.

The disposal of drilling debris can create tremendous problems, particularly when one considers that the drilling of one well can liberate up to 2,000 tons of cuttings. Cuttings produced using water based muds can simply be flushed into the sea, whereas most countries have now prohibited the disposal of oil based mud cuttings in this manner on environmental grounds.

The schematic illustration shows the basic layout of the drilling mud circulation system employed on a rotary table powered drilling rig. The system is identical to that used on the more modern top drive systems with the exception of the Kelly which is no longer required.

- i) The cycle commences as high pressure reciprocating pumps deliver mud to the rotating drill string via the stand pipe, flexible rotary hoses and gooseneck attached to the swivel.
- ii) The mud passes down the centre of the Kelly and into the bore of the drill pipe where it eventually exits around the teeth of the drill bit. The mud acts as a cutting fluid, cooling the drill bit and retaining rock chippings produced by the drilling process in a suspension which can be channelled back up the hole and on to the rig.
- iii) The mud returns are collected within the bell housing situated on top of the diverter or BOP stack and are directed into a shale shaker prior to entry into the settling and storage tanks (or mud pits). The shale shaker consists of a series of vibrating gratings or screens which sieve the mud and remove the particles of drilling debris. Particles removed by the shale shaker are examined to provide the drill team with information pertaining to the physical characteristics and content of the formation through which the drill bit is passing.

Where an improved level of filtration is required centrifuges or hydro-cyclones may be used in addition to the shale shakers to clean up the mud.

- iv) Prior to recirculation of the drilling mud it is allowed to stand in the settling and storage tanks which are open to the atmosphere. This permits the release of any gaseous hydrocarbon products dissolved during the drilling process as will be the case when the drill bit enters a hydrocarbon bearing formation.

## Part 4. OPERATIONS

No account of offshore drilling would be complete without introducing the drill team and providing a brief description of the more routine operations they perform during drilling or "making hole". The terminology reflects the American origins of the industry for whilst it may have been a Scotsman, James Young, who patented the first process for the production of refined petroleum products, it was an American, Colonel Drake, who the same year, 1850 drilled the first well specifically for the production of oil. Colonel Drake's well in Titusville, Pennsylvania produced oil from a depth of 68 feet (20 metres).

Making hole is a particularly time consuming operation. Drilling can proceed at speeds of up to 300 feet (90 metres) an hour or down to 1 foot (0.3 metres) depending on the type of rock formation. A typical well takes approximately 8 weeks to drill and consumes 5 miles of casing and tubing.

Whilst automation is slowly creeping onto the drill floor the environment still dictates that drill crews work long hours in physically demanding conditions.

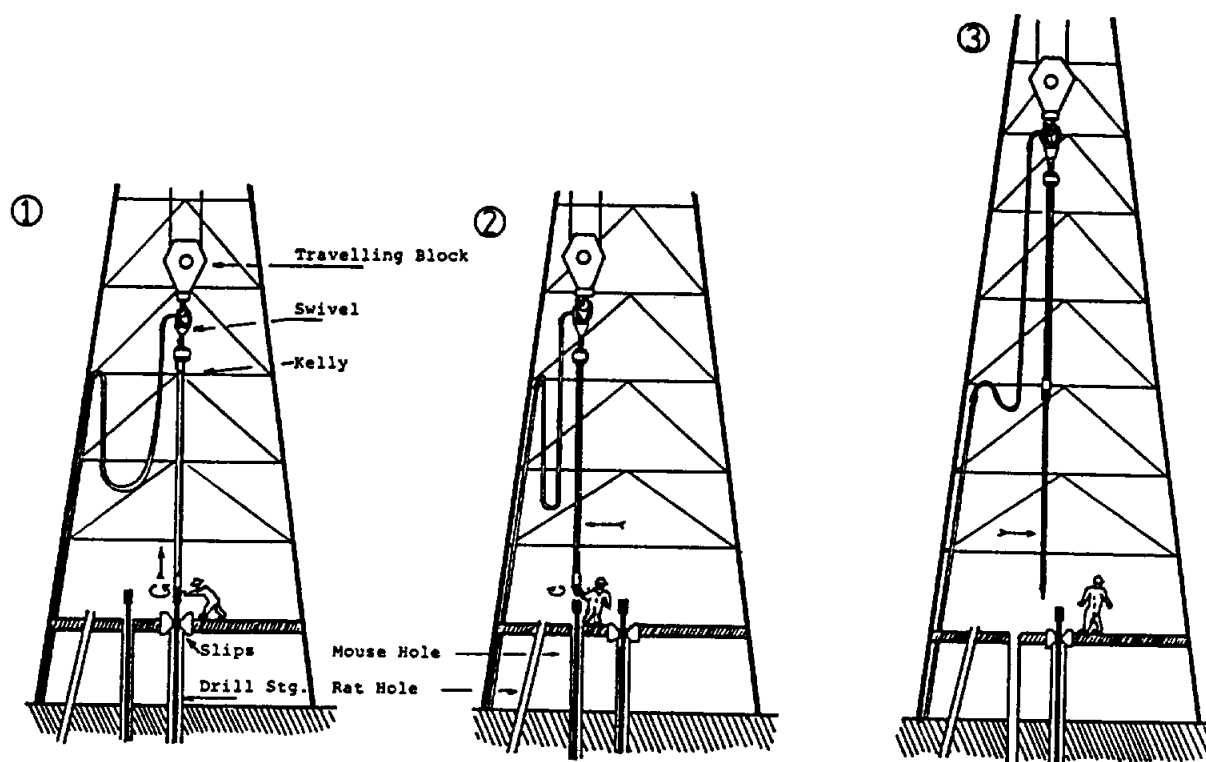
### 1. DRILL CREW

The drill team consists of the following personnel:-

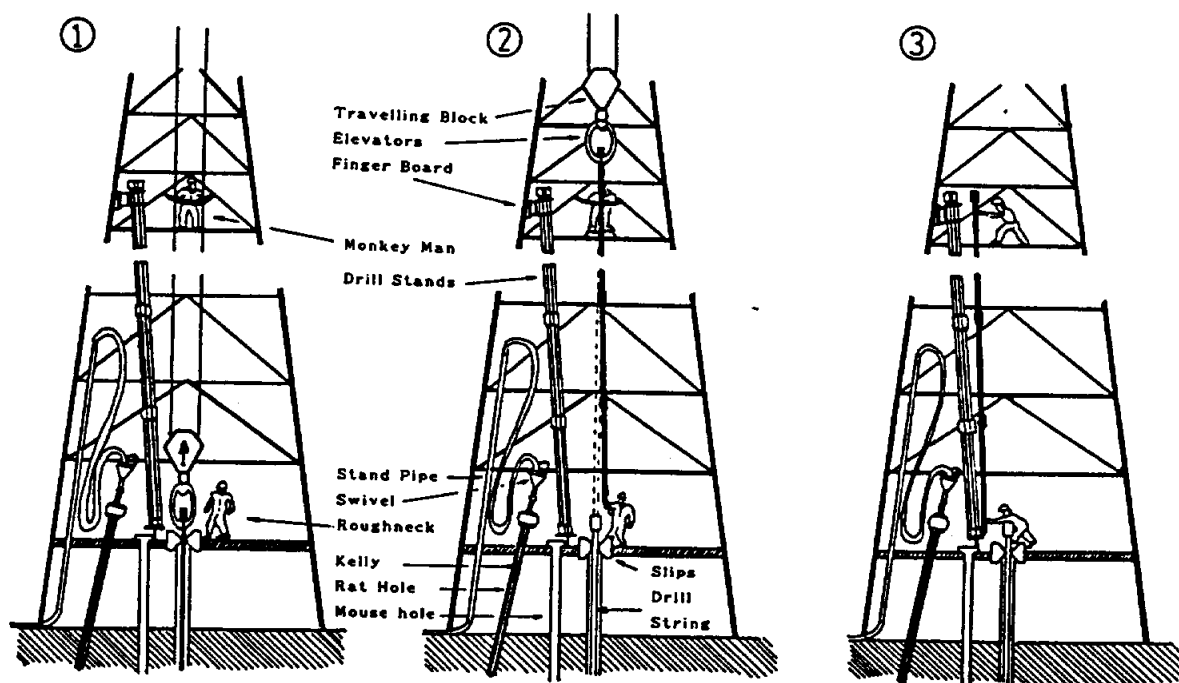
- i) **Toolpusher.** The toolpusher or drilling supervisor is in overall charge of the drilling programme.
- ii) **Driller.** The driller is in charge of all operations carried out on the drill floor, in effect the drill floor foreman.
- iii) **Assistant driller.** The assistant drillers main duties involve the preparation of drill floor machinery.
- iv) **Derrick man.** The derrick man works from the monkey board and assists in the installation and removal of drill pipe during the making of a trip, guiding the stands into and out of the finger board.
- v) **Roughnecks.** Drill floor labourers.
- vi) **Roustabouts.** General rig labourers.

### 2. MAKING HOLE

Whilst the rotary table has largely been superseded by the top drive assembly during the last 10 years, an account of drilling operations using both types of equipment will be given as the rotary table may still be encountered on older installations and as part of drilling history will frequently be referred to offshore.



### MAKING A CONNECTION



### TRIPPING OUT

### i) ROTARY TABLE DRIVE

Rotational movement is imparted to the drill string by the rotary table, via the Kelly bushings. As the hole progresses the Kelly slides through the bushings until approximately 30 feet ( 9 metres ) of hole have been drilled and a new section of drill pipe is required. The addition of drill pipe is referred to as "making a connection" and the process may be compared with the way a chimney sweep increases the length of his brush as it proceeds up the chimney.

To make a connection the rotary table must be stopped and the flow of drilling mud interrupted. The drill string is then lifted by the travelling block until the Kelly is clear of the rotary table.

The Kelly bushings are then replaced by "slips", a pair of wedges which prevent the drill string falling back down the hole when the base of the Kelly is disconnected. The Kelly is connected to a new section of drill pipe located in the mousehole and the complete assembly re-positioned over the drill string. The drill string joints are tightened using a pair of hydraulically powered pipe grips or "tongs" after which the drill string is ready for re-entry into the hole. The drill string weight is once again taken by the travelling block whilst the slips are removed and the drill string is lowered back into the hole. Once the Kelly bushings have been replaced, drilling may continue.

### ii) TOP DRIVE

The top drive assembly employs a large hydraulically or electrically powered motor to impart rotary motion to the drill string. The motor is suspended from the travelling block and 90 feet (27 metres) of hole can be drilled before additional drill pipe is required. The facility to drill three times as much hole as the rotary table between connections represents a considerable saving in time and is the main reason for the success of top drive systems.

To make a connection with a top drive assembly the motor must first be stopped and the flow of drilling mud suspended. The travelling block briefly supports the entire weight of the drill string whilst the slips are inserted into the drill floor. The motor can then be disconnected from the drill string and hoisted into position over a new section of drill pipe.

Drill pipe awaiting inclusion into the drill string is pre-assembled into "stands" consisting of three sections of pipe stood vertically inside the derrick finger board. The drive motor is connected to the top of a stand and the travelling block is used to lift it into position over the drill string whilst the two are coupled together. Drilling may be resumed once the slips have been removed and a further 90 feet of hole drilled.

Whilst the preceding text provides an outline of the way in which a hole is progressed, it will be appreciated that occasions arise which require the removal of the drill string in its entirety, the operation being referred to as "making a trip" or "tripping out". It is a time consuming operation which may require the removal of up to 12,000 feet (3,650 metres) of drill pipe during the latter stages of drilling.

The making of a trip will be required prior to the installation of a casing string and whenever the drill bit requires replacement. Drill bit life will be dependant on the type of formation being drilled but a life of 10 to 72 hours can be expected unless specialized diamond tipped cutters are used.

The tripping operation commences with the suspension of the drill string from the slips in the drill floor. The procedure is identical for top drive and rotary table powered equipment once the Kelly and swivel have been removed. The swivel is replaced with drill pipe elevators, a large clamp arrangement

which grips the drill string below the uppermost drill joint. The travelling block is then raised until three lengths of drill pipe ( a stand ) are exposed and the slips are re-set in the drill floor. The stand is then disconnected and stood vertically up the inside of the derrick, held in the finger board until required for further use. The process is repeated until all the drill pipe has been retrieved from the hole. The procedure is reversed once the new drill bit has been installed.

## Varco.BJ. DRILLING SYSTEMS

### Description:

The Varco Pick-up/Lay-down System PLS, is a new generation pick-up/lay-down system that together with a rig floor pipe racking system drastically reduces the manual handling of pipe on the rig floor and pipedeck. The PLS automatically picks up pipe from special pipe containers which may be loaded onshore or at the pipe yard. The pipe is horizontally transferred to the rig floor where a pipe pick-up boom rotates the pipe vertically and presents it to the arm of the pipe racking system. This eliminates the need to manually latch elevators on the pipe as well as removing the tugger or crane handling of each joint. The danger associated with tailing pipe into the V door and the handling of the pipe on the pipe deck is completely eliminated.

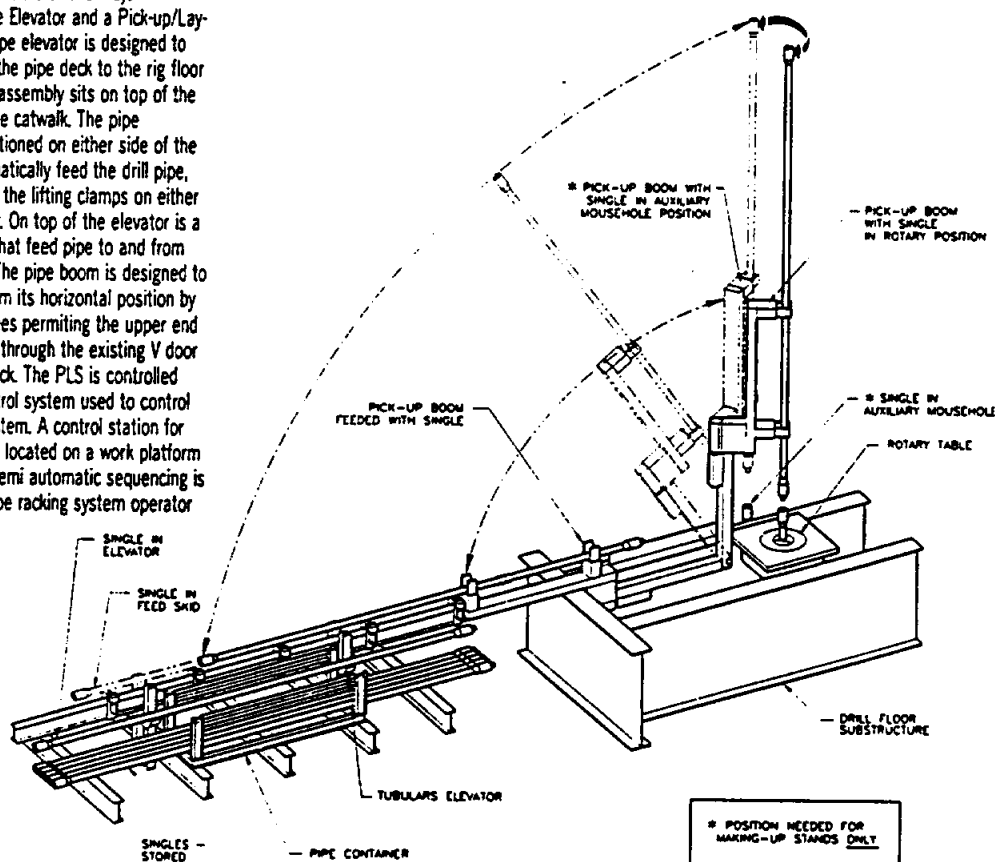
The PLS system consists of two major components, a pipe Elevator and a Pick-up/Lay-down boom. The pipe elevator is designed to raise pipe from of the pipe deck to the rig floor level. The elevator assembly sits on top of the pipedeck next to the catwalk. The pipe containers are positioned on either side of the elevator and automatically feed the drill pipe, collars or casing to the lifting clamps on either side of the elevator. On top of the elevator is a series of V rollers that feed pipe to and from the pick-up boom. The pipe boom is designed to pick-up the pipe from its horizontal position by rotating it 90 degrees permitting the upper end of the pipe to pass through the existing V door opening in the derrick. The PLS is controlled from the same control system used to control the pipe racking system. A control station for manual operation is located on a work platform near the rig floor. Semi automatic sequencing is controlled by the pipe racking system operator from his console.

### Benefits:

- Eliminates the need to feed each joint of drill pipe, collars or casing into the V door by crane
- Can be combined with a PHM racking system for fully automatic operation
- Can be operated in manual mode if required
- Reduces the number of Roustabouts required
- Improves pipe deck safety

### Specifications:

Elevator High Speed: 2 ft per sec  
Elevator Low Speed: 6 inches per sec  
Boom Elevation Time: 18 sec  
Pipe Sizes High Range: 9-3/4 to 20 inches  
Pipe Sizes Low Range: 3-1/2 to 9-3/4 inches



Varco BJ Pick-up/Lay-down System PLS

## AUTOMATED DRILL PIPE HANDLING SYSTEMS (Reproduced with permission of Varco BJ, Orange, California)



## PART 5. WELL CONTROL EQUIPMENT

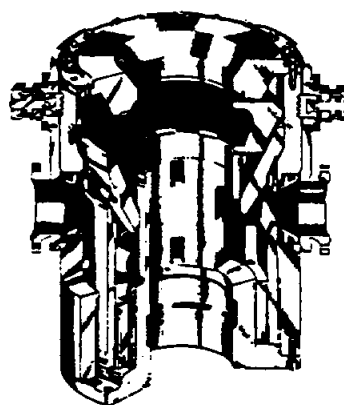
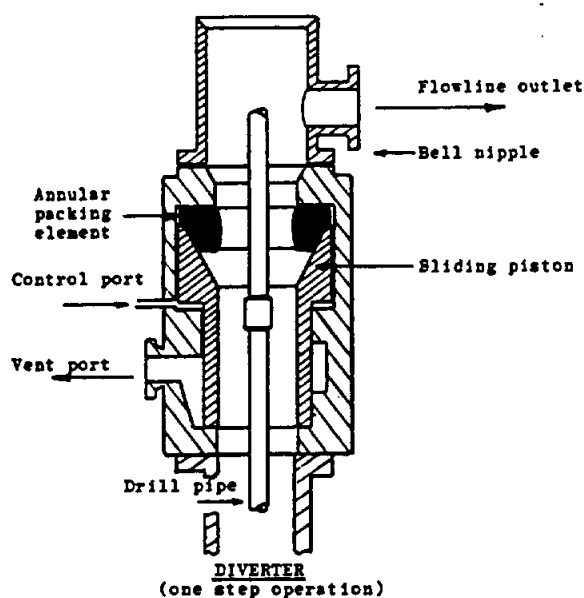
The diverter and blowout preventer (BOP) are probably the two most important items of equipment on a drilling rig and their description has been left until last because to understand their function one must first have a basic appreciation of drilling operations. Basically, diverters and BOP's are the last line of defence which provide the drill crew with a breathing space to take corrective action, or abandon the installation when control of the well is lost.

The initial stages of drilling a well are without doubt the most dangerous due to the ever present risk of penetrating shallow gas bearing sands, a hazard which has resulted in numerous fatalities and the complete destruction of both drillships and jack-ups. The diverter is used in preference to a BOP to provide a degree of protection against these hazards because attempting to confine hydrocarbons within a shallow conductor may lead to a blowout of the formation around the outside of the conductor which would create an unrecoverable situation. Once the hole depth has been substantially increased and the first intermediate casing string cemented in place the diverter can be replaced with a BOP stack.

### For Floating Offshore Drilling Rigs

The FS 21-500 is a diverter with a 21 inch bore and 500 psi working pressure rating. Drillships and semisubmersibles employ a diverter for venting gas flows encountered while drilling top hole through the 30 inch casing. The diverter also serves as the support for the upper flex joint and the inner barrel of the riser telescopic joint, so the diverter is in place whenever the riser is in service. On a floating rig, the diverter is never used as a BOP, so its pressure rating is 500 psi. Its bore accommodates the riser bore.

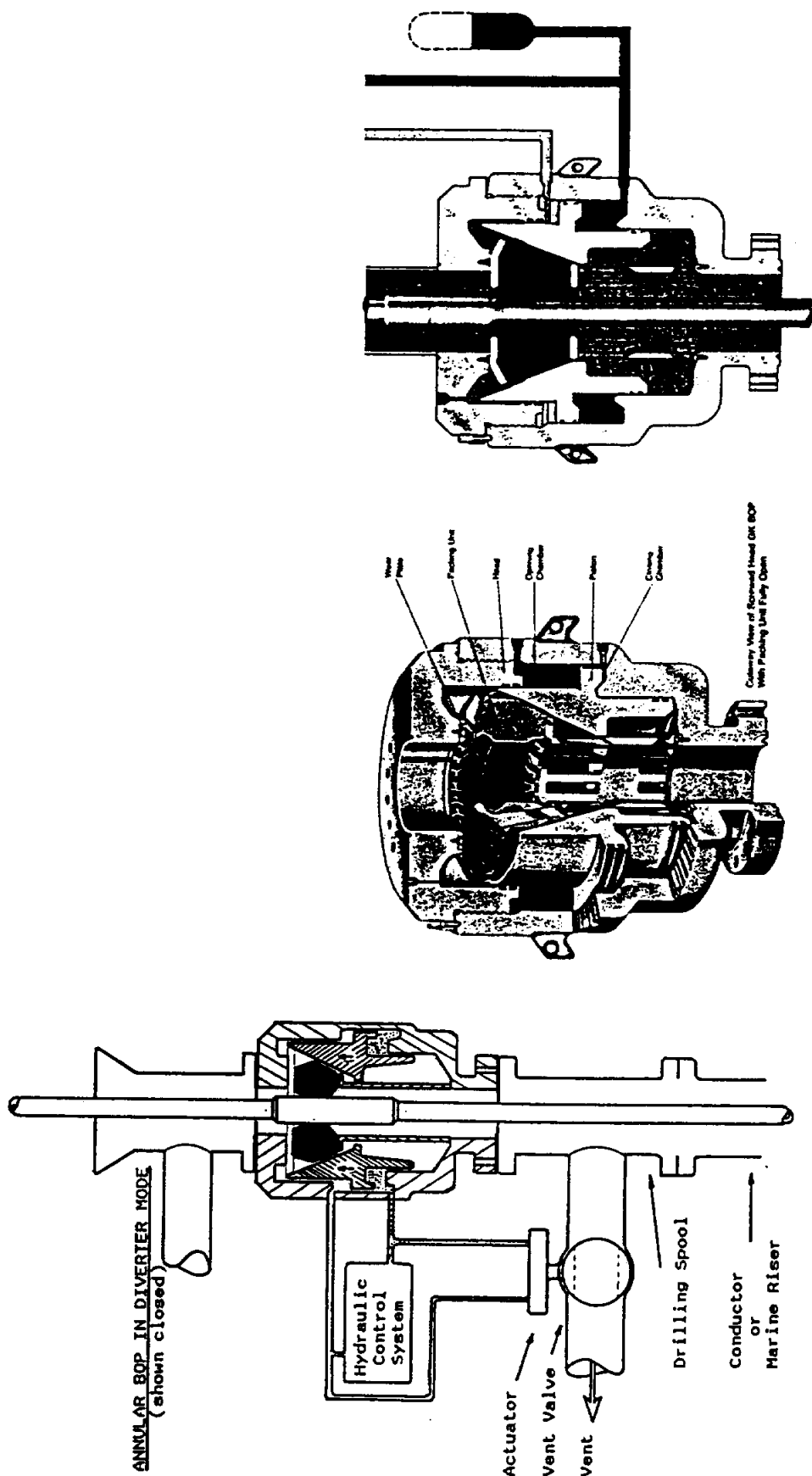
The FS diverter is fundamentally simple. Its design avoids the functional complexities which increase chance for human error



**FS 21-500 Marine Riser Diverter, internal view.**  
The FS is simple and safe. The piston moves up and closes the annular packing unit, stopping upward flow. The sleeve opens the vent and closes the flowline. The FS can be fitted with two vent outlets.

### MARINE RISER DIVERTER

(Reproduced with permission of Hydril, Houston, Texas)



**ANNULAR BLOWOUT PREVENTER**  
(Reproduced with permission of Hydril, Houston, Texas)

## 1. THE DIVERTER

As the name suggests, the diverter provides a means of diverting an unexpected release of well fluids, primarily gas and occasionally solids, to a location at the extremities of the rig where they can be discharged safely.

The diverter is situated on top of the conductor and must permit the passage of the drill bit whilst still being capable of effecting a seal around the drill pipe or Kelly. During normal drilling operations the diverter vents are closed and the drilling mud returns flow upwards and into the bell housing from whence they are channelled into the shale shaker. Activation of the diverter results in the closure of the packing element around the drill string and the sequential opening of the vents, thus providing an unrestricted passage to atmosphere for well fluids.

The diverter may consist of a proprietary item or it may be assembled from a fabricated manifold and a conventional annular blowout preventer (BOP). The illustrations show a diverter in which the constriction of the packing element, the opening of the vent port, and the closure of the flowline port are combined into a single operation controlled by the annular piston, an inherently more reliable arrangement than can be achieved with built up diverters.

The drilling of wells from a floating rig semi-sub or drill ship necessitates location of the BOP stack on the ocean floor. In these cases a diverter is normally mounted on top of the marine riser as a precautionary measure throughout the drilling programme.

The most noteworthy development in diverter technology in recent years has been the concept of diverting at the wellhead rather than on the rig. This is accomplished by siting a diverter on the sea-bed in addition to the diverter on top of the drilling riser and permits the venting of well fluids into the sea. The risks associated with a possible release of gas on the drill floor during the early stages of drilling are thus avoided.

## 2. THE BLOWOUT PREVENTER

The primary function of the blowout preventer is to confine well fluids within the well bore. It operates as part of a BOP system which includes the BOP stack, choke and kill valves, choke manifold and a hydraulically powered control unit.

There are two basic types of blowout preventer, that is the annular type and the ram type, examples of which are shown in the illustrations.

### i) ANNULAR BOP'S

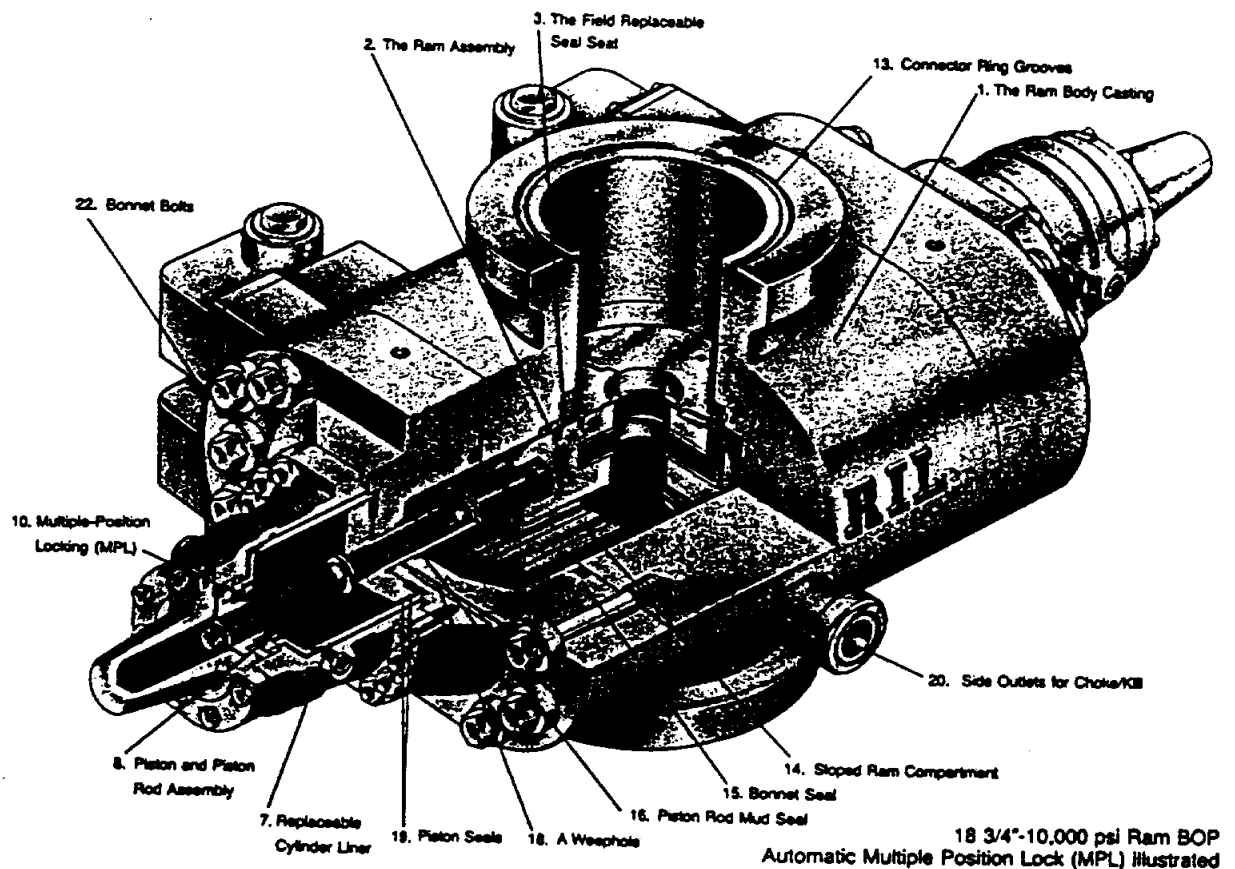
The annular BOP relies on the constriction of a reinforced elastomeric packing element to effect a seal around the drill pipe or Kelly. The flexible packing element can accommodate considerable changes in diameter and cross section but it typically cannot withstand pressures as high as a ram type BOP. Consequently, it is used in conjunction with ram type BOP's which are better suited to retaining extremes of reservoir pressure. In addition to containing well-bore pressure, annular BOP's are also used for "stripping" and "snubbing" operations which involve the vertical movement of drill pipe and casing into or out of the well under well pressure.

ii) RAM TYPE BOP'S

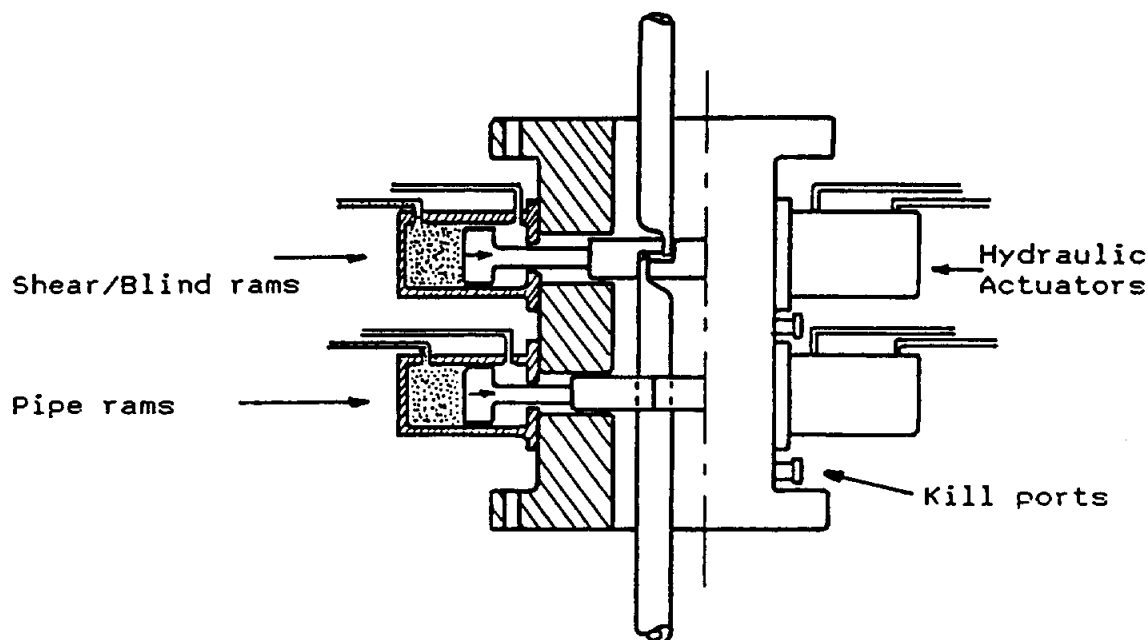
As previously stated, ram type BOP's are used in combination with an annular BOP and may feature any one of four ram configurations:-

- a) **Pipe rams.** These are supplied in various sizes and are designed to close and seal around the drill pipe.
- b) **Variable rams.** These are capable of closing and sealing on a limited range of pipe sizes.
- c) **Blind rams.** These seal against each other and are designed to seal the well bore in the absence of the drill pipe.
- d) **Blind/shear rams.** These are primarily used during subsea drilling operations where weather conditions may necessitate the rapid disconnection of the rig from the well. The blind rams incorporate a cutting edge capable of severing the drill string and sealing high pressure, high temperature well fluids within the well bore for an extended period of time.

A hydraulically controlled power unit typically provides the fluid power for operation of the rams, and the annular piston used in the annular BOP's.



**RAM BLOWOUT PREVENTER**  
(Reproduced with permission of Hydril, Houston, Texas)



RAM TYPE BOP SCHEMATIC

### 3. BOP OPERATIONS

Drilling operations proceed through the centre of a BOP stack which is mounted on top of the casing head. The stack consists of a drilling spool incorporating choke and kill connections, an annular and at least one ram type BOP. As anticipated well pressures increase, additional sets of rams are installed up to a maximum of three sets. A typical surface mounted high pressure well BOP stack would consist of one annular BOP, two sets of pipe rams and one set of blind/shear rams. A subsea BOP stack normally contains an additional set of pipe rams and two annular BOP's.

During normal drilling operations both ram and annular BOP's are held in the open position there being no hydrocarbon pressure within the hole. Should the drill bit penetrate an unexpected pocket of oil or gas the hydrostatic head created by the drilling mud should prevent well fluids from entering the hole.

When the drill bit enters a hydrocarbon bearing formation and the hydrostatic head exerted by the column of drilling mud is insufficient to cope with the formation pressure, the well fluids will commence displacement of the drilling mud which will be indicated by an increase in the volume of mud returning to the mud tanks. This situation is referred to as a "kick" and must be dealt with immediately if it is not to escalate into a full "blowout".

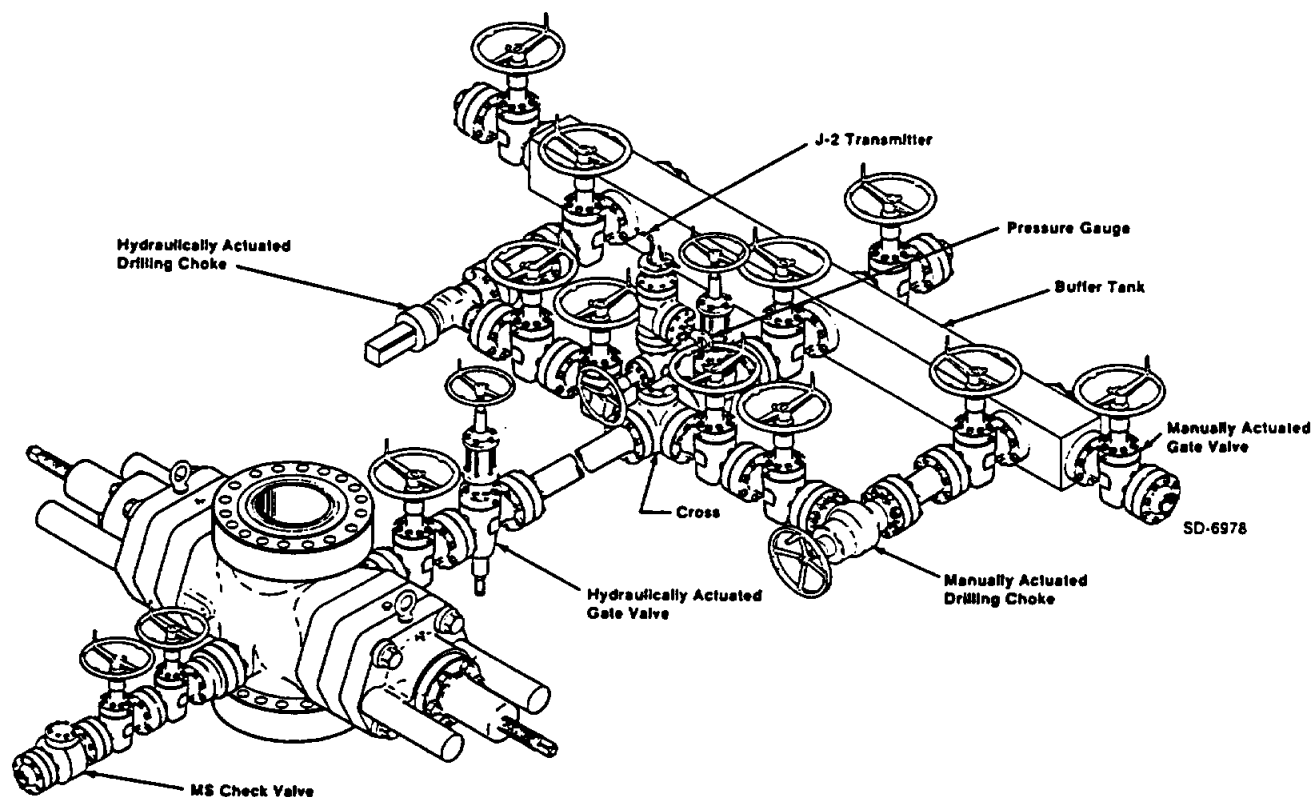
To control a kick the drill crew must first close the BOP pipe rams and the Kelly cock in order to contain the formation pressure within the well bore. Eventually the pressure will stabilise at which time a specially prepared mixture of dense drilling mud can be pumped into the well via the kill connections located on the drilling spool or BOP. The well pressure is thus neutralised by circulating the mud back through the choke line to the choke manifold. Having successfully "killed" the formation pressure with the hydrostatic head of mud, drilling may be resumed.

Should it be necessary to reduce the pressure within the well bore at any time during the well kill operation, this may be effected via the choke manifold connected to the drilling spool. The choke contains a variable orifice through which well pressure may be vented to atmosphere.

A blowout occurs when a rapid increase in reservoir pressure displaces the drilling mud from the hole, causing a release of oil, gas or solids. This situation is virtually unrecoverable and should obviously be avoided at all costs. When all else fails activation of the shear rams should cut and seal the drill pipe and provide valuable time in which corrective action, or abandonment of the installation may be effected.

Further information pertaining to blow-out prevention equipment can be found in the American Petroleum Institute (API) Recommended Practises (RP).

- i) API RP 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells (officially discontinued but still available).
- ii) API RP 64, Recommended Practice for Diverter Systems, Equipment and Operations.
- iii) API RP 16E, Recommended Practice for the Design of Control Systems for Drilling Well Control Equipment.



**CHOKE AND KILL MANIFOLD**  
(Reproduced with permission of Cooper Oil Tools, Houston, Texas)

## ***Part 6. FLOATING DRILLING VESSELS***

Having described the process and equipment used to drill a well from a bottom supported structure such as a jack-up or fixed installation, we must now consider the situation where water depths dictate that drilling operations are carried out from a drill ship or semi-submersible vessel (semi sub).

The procedure for drilling a well is relatively unaffected by the type of vessel employed, be it fixed or floating. The major changes occur in the selection of equipment used to occupy the space between the sea bed and the drill floor. This equipment must include a motion, or heave compensation system that will accommodate vessel movement relative to the sea bed.

A sketch has been prepared to assist in the explanation of the various components required to carry out drilling operations from a floating vessel.

### **i) GUIDE BASE**

The first operation entails installation of a guide base on the sea bed through which drilling operations may proceed. Wires extending from the drill ship to the guide base assist in the location of the drill string and wellhead equipment.

Prior to commencement of drilling the conductor pipe must be "spudded" (piled) through the guide base and into the sea bed. The conductor stabilises the soft sea bed, provides a passage for the disposal of drill cuttings and incorporates a suspension system for the support of the intermediate casing strings. The top of the suspension system is fitted with a machined collar designed for attachment to a wellhead coupling.

### **ii) BLOWOUT PREVENTER (BOP) STACK**

When drilling operations are carried out from a floating vessel, the blowout preventer is mounted on the sea bed. This ensures that should an emergency situation necessitate suspension of the drilling programme and departure of the vessel, the well may be left in a secure condition.

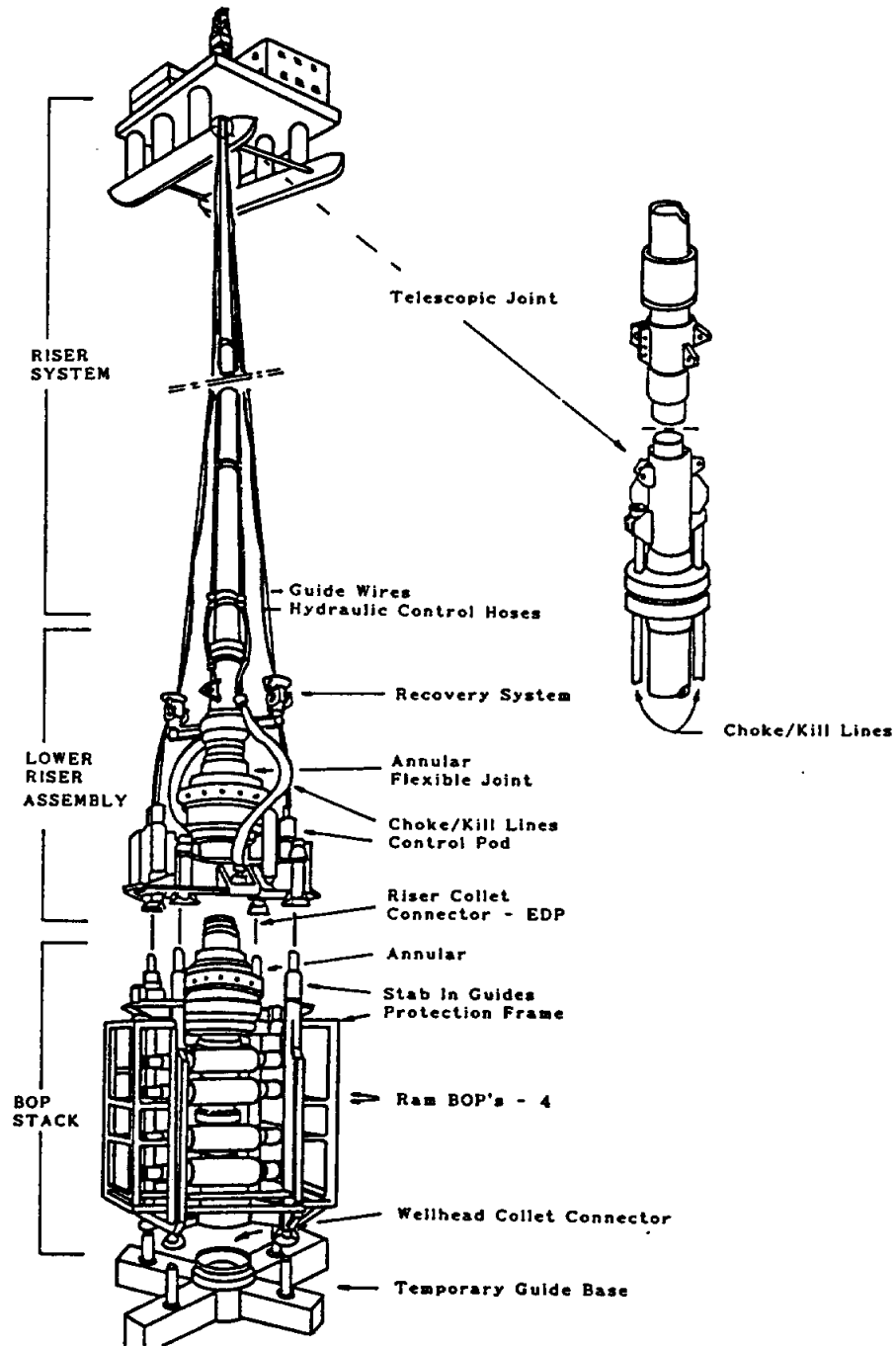
The BOP stack consists of a combination of annular and ram type BOP's housed within a tubular framework. The framework provides protection during transportation and incorporates location devices to assist in the attachment of the stack to the guide base. Remotely operated hydraulic couplings connect the base of the BOP stack to the conductor, and the top of the stack to the riser. The uppermost connector is frequently referred to as the emergency disconnect package (EDP).

### **iii) MARINE RISER FLEXIBLE JOINT**

A flexible ball joint located between the EDP and the marine riser can tolerate a certain amount of lateral movement of the drill ship relative to the wellhead. A second ball joint is attached to the top of the riser, frequently incorporated within the diverter.

### **iv) MARINE DRILLING RISER**

The length of steel pipe extending from the BOP stack to the drill ship is referred to as the marine drilling riser and it provides a return passage for the drilling mud. The riser incorporates a telescopic joint, the top half of which is attached to a tensioning system.



## DRILL SHIP EQUIPMENT

### v) TELESCOPIC JOINT

The telescopic joint permits relative vertical movement between the stationary lower section of drilling riser which is attached to the sea bed and the upper section of drilling riser which is connected to the drilling derrick. It consists of a hydraulic or pneumatically activated packing element which is located in the top section of drilling riser.

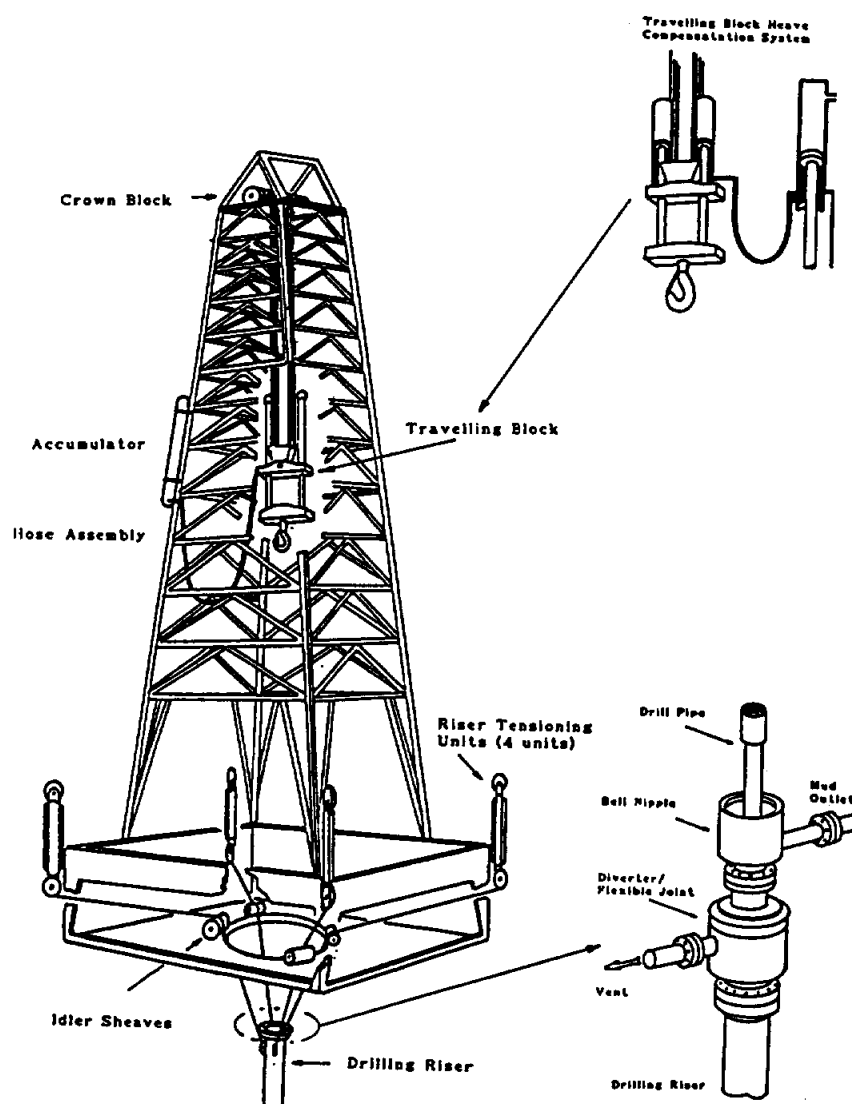


## vi) THE RISER TENSIONING SYSTEM

The riser tensioning system, or heave compensation system, is designed to keep the drilling riser in tension and to minimise the effects of hull movement. It can accommodate up to 15 metres (50 feet) of vertical wave induced motion or heave. Wires emanating from the upper section of drilling riser are connected to hydraulic/pneumatic cylinders which act like shock absorbers, extending as the vessel rides up and compressing as the vessel moves down.

## vii) DRILL STRING TENSIONING SYSTEM

The travelling block is fitted with a heave compensation system that is similar to, if somewhat less sophisticated than that employed to tension the riser. The hook is separated from the travelling block and mounted within a pneumatic/hydraulically activated piston assembly which ensures that a constant load is maintained on the drill string at all times.



DRILLING DERRICK ASSEMBLY

**viii) DIVERTER**

The diverter sits on top of the drilling riser and provides a means of controlling an influx of hydrocarbons into the well bore during the early stages of drilling, should one occur.

**ix) CHOKE AND KILL LINES**

Subsea choke and kill line connections are arranged slightly differently to those on a surface well inasmuch as they are manifolded to permit pressure release, or the pumping in of drilling mud through either connection.

They are run down the outside of the marine drilling riser in hard steel pipe with flexible couplings providing the means of attachment to the BOP stack. The choke and kill line connections to the vessel are by means of flexible hoses suitably dimensioned to absorb wave induced motion.

## **2. DIRECTIONAL DRILLING**

Directional drilling was developed primarily to permit the exploitation of hydrocarbon bearing formations at locations horizontally distant (up to 8km) from fixed installations that would otherwise necessitate an additional platform or subsea well.

The two most common techniques employed to drill a deviated hole are:-

**i) JET BIT**

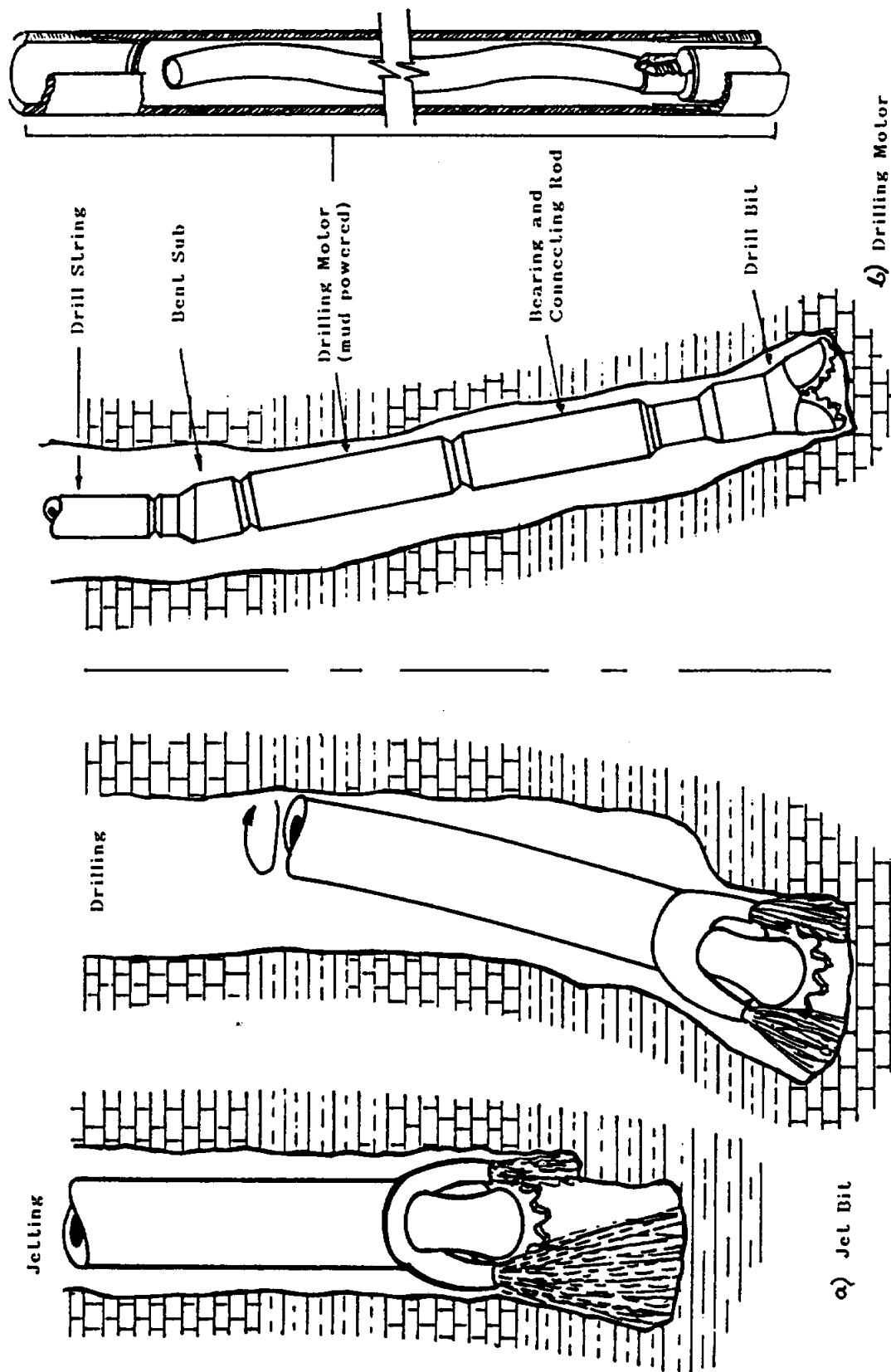
The jet deflection processes utilize a triple jet drill bit in which one of the drilling mud outlet connections or jets is considerably larger than the other two. The large jet is positioned in the desired direction of deviation whilst high pressure drilling mud is pumped through the stationary drill bit. The impact force provided by the mud erodes a hole into which the drill string will track on resumption of drilling. The process is simple and effective.

**ii) DRILLING MOTOR**

The drilling motor consists of a hydraulic turbine which is attached to the drill bit by a replaceable bearing section. It is powered by drilling mud and a bent sub permits orientation of the drilling motor to the required angle of deviation.

Recent events have lead to the development of advanced drilling motors which can be used to drill horizontal wells, a process which greatly enhances the productivity of oil and gas from thin hydrocarbon bearing formations. Deviation of the hole from the vertical to the horizontal position is a very gradual process which can involve up to 8,000 feet (2,500 metres) of vertical hole and 6,600 feet (2,000 metres) of horizontal hole. These large distances and the natural flexibility of the steel casing and tubing permit the well to be completed in a manner identical to a conventional vertical well.

Whilst still regarded as new technology horizontal drilling has proved remarkably successful and permitted the development of reserves which were previously considered unrecoverable.



DIRECTIONAL DRILLING

## Varco B.J.

DRILLING SYSTEMS

### Description:

The Type V Racking System was designed primarily to improve the efficiency and safety of drilling operations on Drillships and Semi-Submersibles where vessel motion makes handling tubulars dangerous and inefficient.

The Type V Racker System consists of three pipe racker assemblies normally located on the same side of the derrick as the setback area. Each assembly consists of a racker arm capable of moving in and out (towards and away from the rig centerline) and a carriage that moves laterally across the derrick. A racker head assembly on each arm is used to grip the pipe. In a typical tripping operation, the upper racker arm guides the upper end of the stand between well center and the fingerboard while the intermediate racker arm lifts and guides the lower end of the stand. The operation of the upper and intermediate racker arms are controlled from the derrickman's and assistant driller's consoles, respectively.

The lower racker arm is used to assist in the handling of tubulars at the rig floor. The operation of handling the kelly, casing, collars, and marine risers can now be easily and safely performed. The lifting force and vertical motion of the intermediate racker lifting head is provided by a stand lift cylinder assembly controlled from the assistant driller's console. In a variation on the basic three arm Type V Racker System, the lower racker arm is replaced with the hydraulically powered Telescoping Arm which is normally mounted on a pedestal on the rig floor. The substitution of the lower racker arm can provide more operating flexibility in some cases.

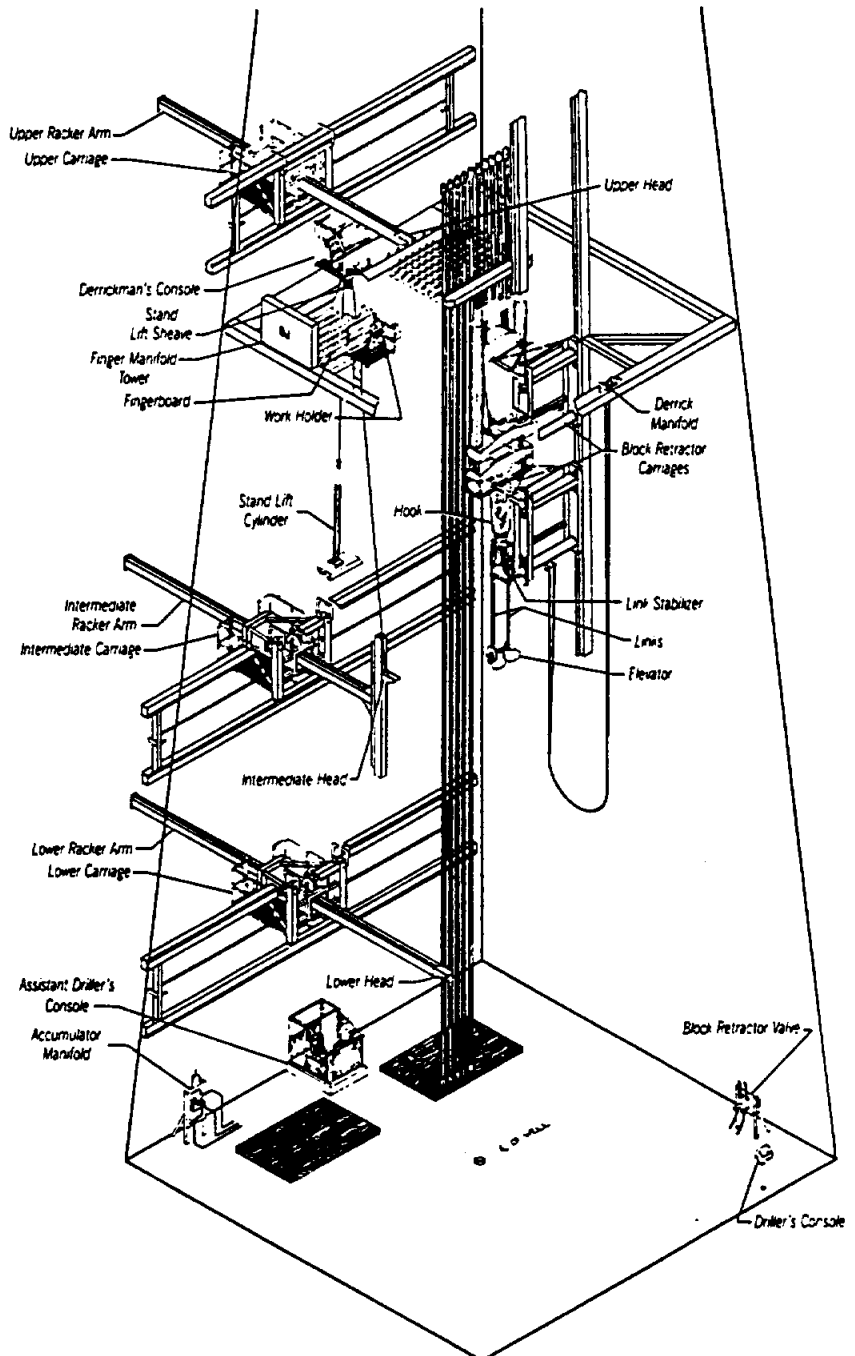
For maximum efficiency and reduction in trip times the system should be combined with a remotely operated Varco pneumatically powered fingerboard, air operated elevators and a retract system on the Top Drive/Traveling block.

### Benefits:

- Greatly improves rig floor safety
- Simple Electro/Hydraulic System
- Provides remote control racking
- Lower Maintenance Costs
- Reduces trip time when used in conjunction with a retract system.

### Specifications:

Pipe Size (inches): 3-1/2 to 9-1/2  
Lifting Capacity: 20,000 lbs  
Max Reach: Customer specified  
Max Push: 4,000 lbs



Varco B.J. Type V Three-Arm Racker System

## AUTOMATED DRILL FLOOR EQUIPMENT

(Reproduced with permission of Varco B.J., Orange, California)

## **Chapter Eight**

### **THE WELL - COMPONENT PARTS**

PART 1. CHRISTMAS TREE.

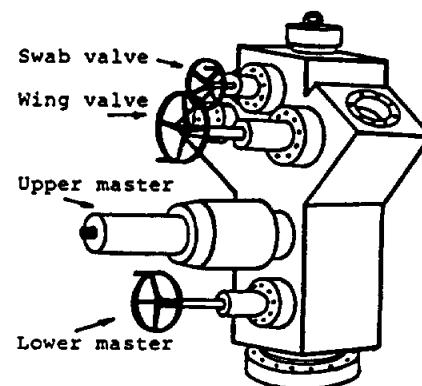
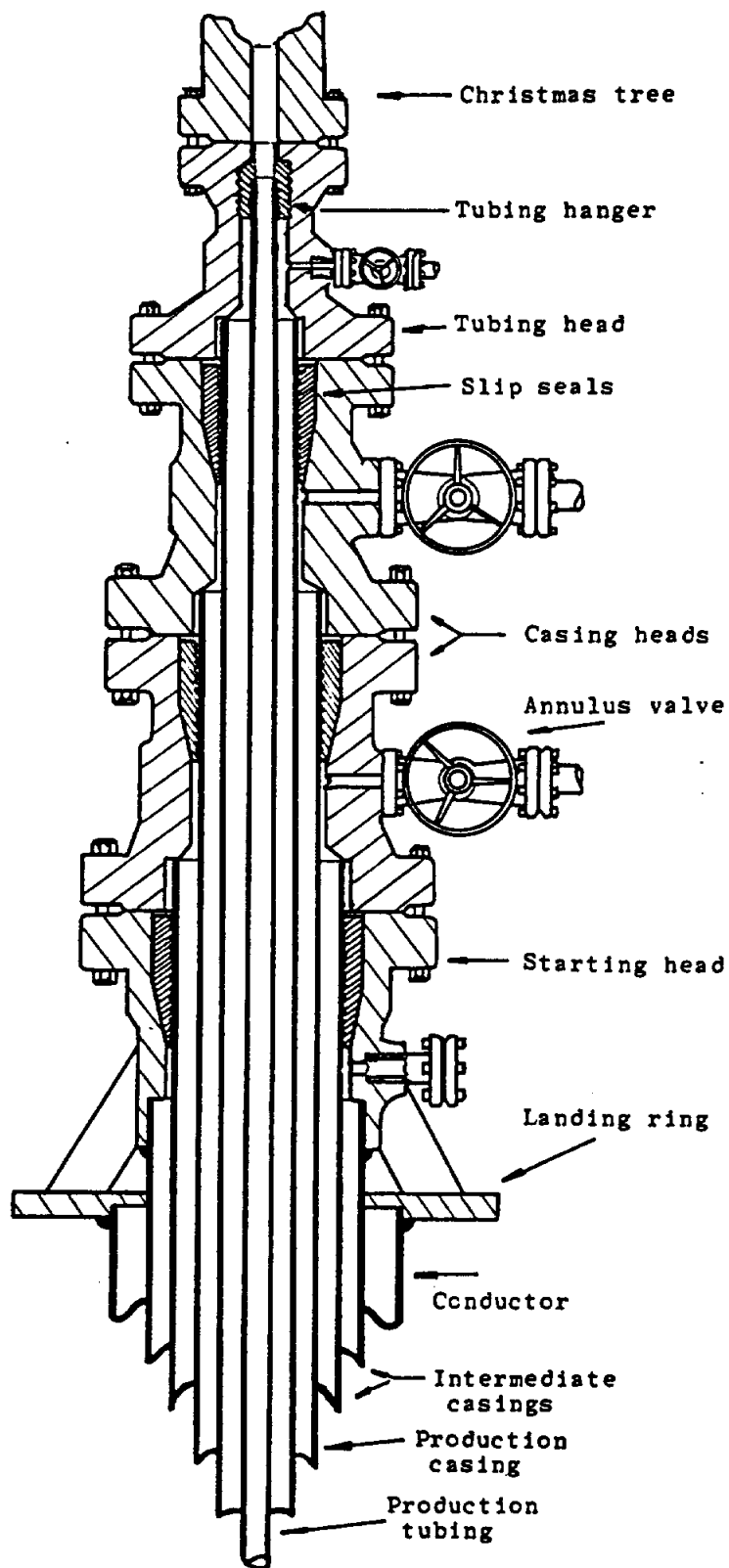
PART 2. SURFACE WELLHEAD.

PART 3. MUDLINE SUSPENSION SYSTEM.

PART 4. MUDLINE SAFETY VALVE.

PART 5. PRODUCTION PACKER.

PART 6. EMERGENCY SHUTDOWN SYSTEM.



THE CHRISTMAS TREE

## Part 1. THE CHRISTMAS TREE

The christmas tree is essentially the heart and soul of the offshore (and onshore) hydrocarbon production system. It is the primary means of well control and plays a key role in the emergency shut down (ESD) system.

The christmas tree sits on top of the wellhead casing system and represents the interface between the well and the production and process facility.

The tree consists of an assembly of gate valves which control the flow of hydrocarbons. It may consist of individual valves bolted together from which the name "christmas tree" was originally derived, or it may feature a cast or forged steel "solid block" into which the valve chests are machined. Occasionally it is a combination of the two. In all cases the valve seats and gates are removeable for replacement or repair.

A wellhead skid controls the operation of the christmas trees and mudline safety valves. The skid permits valves to be operated locally, remotely or via the ESD system and timing mechanisms provide a means of controlling the speed and sequence of valve operation. This sequence would normally be:-

### TO CLOSE

- i) Wing valve.
- ii) Master valve.
- iii) Mudline safety valve.

During an ESD operation, complete closure of the christmas tree valves should be effected within approximately 45 seconds according to API recommendations, the only organisation to provide guidance on this particular aspect.

### TO OPEN

- i) Mudline safety valve.
- ii) Master valve.
- iii) Wing valve.

A christmas tree will normally consist of the following valves:-

## 1. MASTER VALVE OR VALVES

This isolates the tree from the production tubing. The more modern trees have two master valves referred to as the upper and lower master valves. The lower master valve is opened first and closed last. This ensures minimal flow of hydrocarbons over the valve seat, thus protecting it from abrasive particles and ensuring a good seal is maintained.

In most cases the lower master valve is manually operated and the upper master valve is operated via a hydraulic or pneumatic actuator and is connected into the ESD system.

These actuators are fail safe in operation. The valve is held open by oil or air pressure against a compressed coil spring.

Modern christmas trees are fitted with a wire cutting master valve. Should an emergency situation arise when wireline operations are in progress the valve will close and cut the wire. The wire and tool string can be recovered at a later date.

## **2. WING VALVE**

christmas trees may be manufactured with one or two wing valves. One valve is permanently connected to the hydrocarbon process system and is fitted with a hydraulic or pneumatic actuator. The other valve is manual in operation and permits injection of chemicals or gases into the well without disturbing production pipework.

Both valves are offset from the vertical line so that a clear entry into the well is maintained through the swab valve for wireline work. The flow of gas from the well may be regulated by wing valve operation or by a choke fitted above the wing valve.

## **3. SWAB VALVE**

The swab valve is positioned directly above the master valve and permits entry into the well when wireline equipment is attached.

The valve is manually operated and the top connection is fitted with a swab cap to protect the threads and prevent the accumulation of debris.

Further information pertaining to christmas trees can be found in the:-

- i) American Petroleum Institute (API) publication entitled, API Spec. 6A, Specification for Wellhead and christmas Tree Equipment.
- and
- ii) The Department of Energy Guidance Notes on Offshore Installations: Guidance on Design, Construction and Certification, Part II, Section 43.



## ***Part 2. THE SURFACE WELLHEAD***

The wellhead assembly on a fixed installation consists of a collection of components designed to support and seal the intermediate casings, production tubing and christmas tree. It also provides a base for the location of the blowout preventer (BOP) during drilling operations.

Assembly of the wellhead commences with the installation of the conductor pipe and the various stages can best be described with the aid of a sketch.

### **1. BASE PLATE/LANDING RING**

Once the conductor has been driven to the desired depth the base plate or landing ring can be positioned and welded. Landing rings are used to help distribute wellhead loads through the conductor and in to the formation. It should be noted that these components are designed specifically to support the casing strings and are not required to be pressure retaining. At this stage in the drilling operation the formation should be of a type which can not support the existence of hydrocarbons.

### **2. STARTING HEAD**

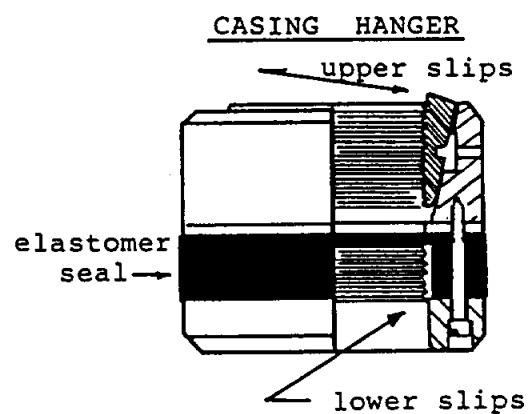
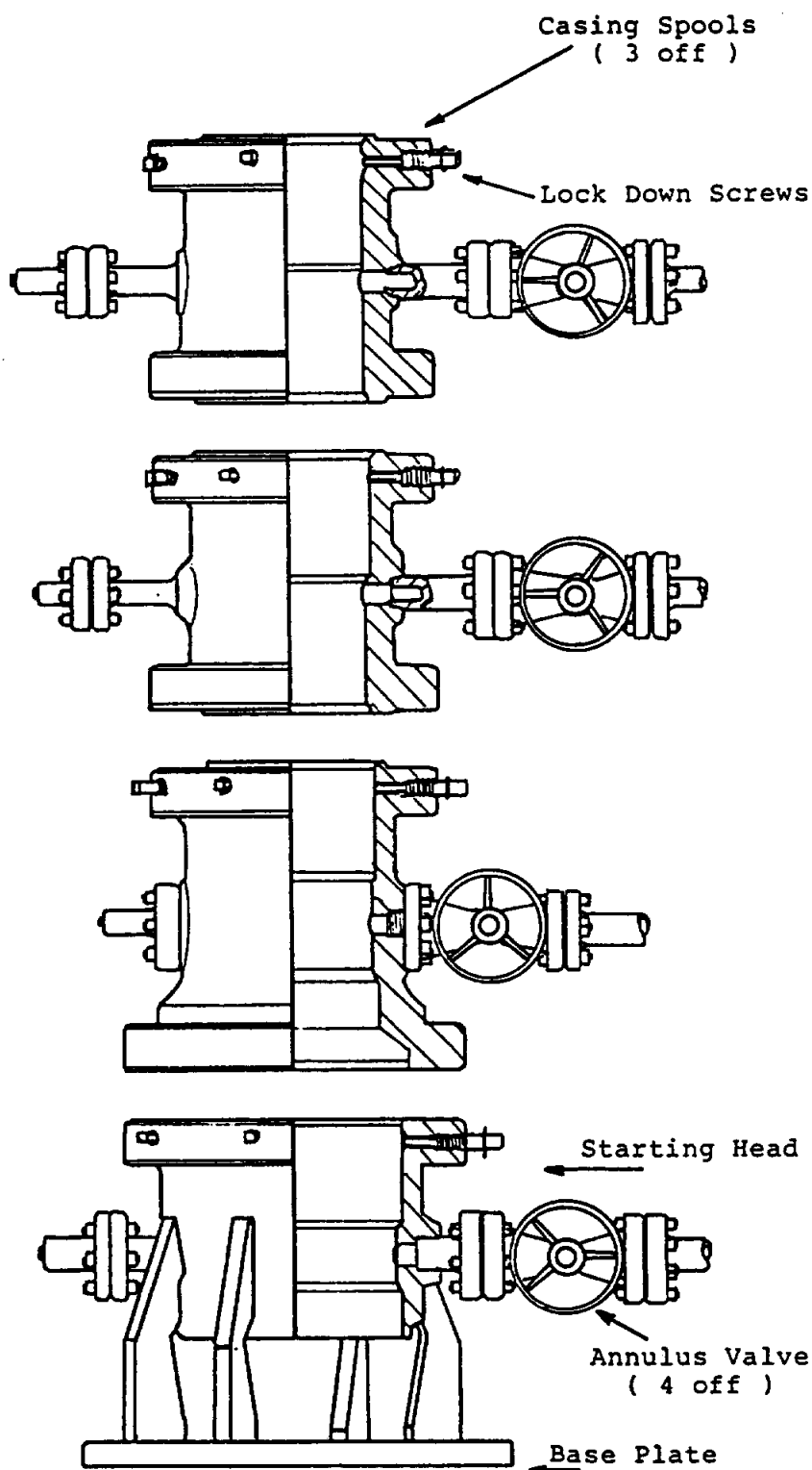
Depending on the design the starting head may be screwed on to, or welded to the top of the first intermediate casing string and it may incorporate a landing ring. The function of the starting head is to transmit the loads created by subsequent casing strings through to the conductor, and to provide the initial location for the blowout preventer.

The blowout preventer will remain in place for the remainder of the drilling operation being moved on to each subsequent casing head in turn.

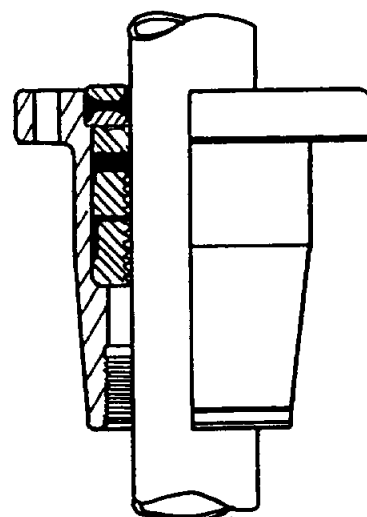
### **3. CASING HEAD SPOOLS**

Following the installation of the starting head, all subsequent casing strings will be terminated within a casing head spool. The spool is designed to support and seal the upper section of casing against oil or gas pressure and provide connections through which the condition of the annulus spaces may be monitored during production, and for the cement returns during installation. Generally speaking, the casing head spool is installed after the casing has been cemented, but before the cement has cured.

Examples of casing head support and seal arrangements are shown highlighted in the sketch. The casing slips or hangers are manufactured with a serrated steel internal face designed to bite into the casing string and thus provide support within the casing head, and a metal to metal seal. A secondary rubber or neoprene "pack off" seal may then be activated under the compression forces provided by external lock down screws or internal cap-head screws. This two-fold sealing arrangement may vary slightly from one manufacturer to another but the basic principles of operation remain the same.



CASING HEAD SPOOL,  
CASING AND HANGER



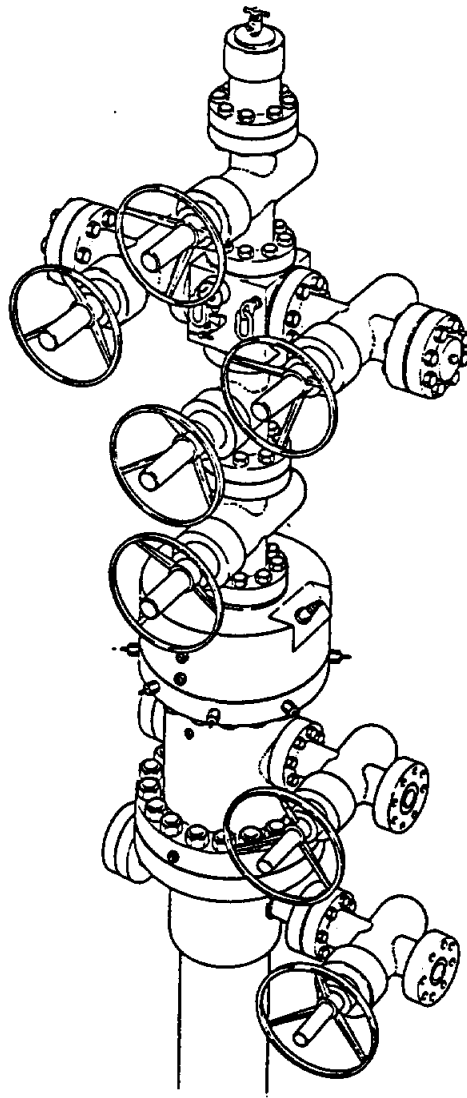
**THE WELL COMPONENT PARTS**  
(Reproduced with permission of Cooper Oil Tools, Houston, Texas)

#### 4. TUBING HEAD SPOOL

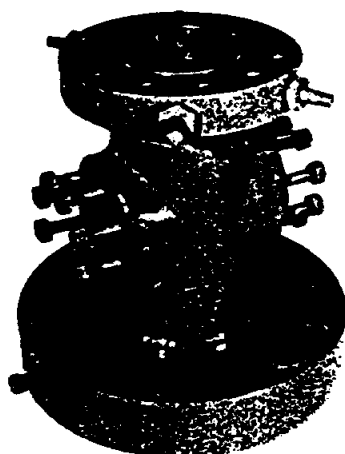
The tubing head spool provides a location arrangement designed to support the production tubing within the production casing. The production tubing sits in a bushing or tubing hanger and is the only item within the well which receives direct exposure to reservoir pressure. The intermediate casings and casing head spools are designed to resist well pressure but will only be subjected to pressure should failure of the production tubing packing seals occur, or a gas lift enhanced oil recovery system is fitted.

#### 5. CHRISTMAS TREE

The final operation consists of installing the christmas tree in preparation for bringing the well "on stream". The christmas tree permits isolation of the reservoir products from the process equipment.

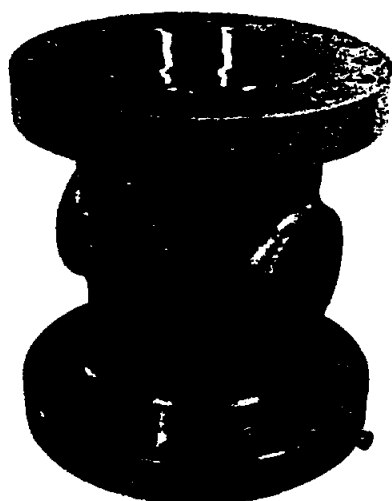
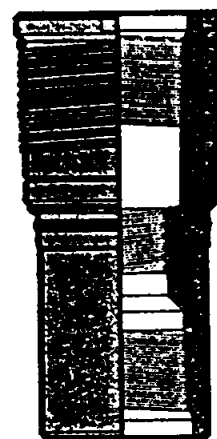


WELLHEAD COMPONENTS - SCHEMATIC

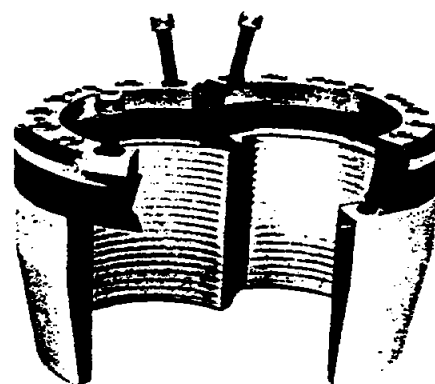


Type U Tubing Head Body  
With Studded Outlets

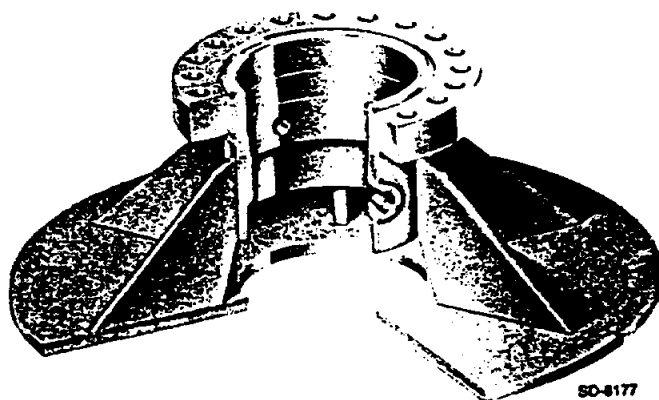
Type WBU and WB-20  
Tubing Hanger Bushings



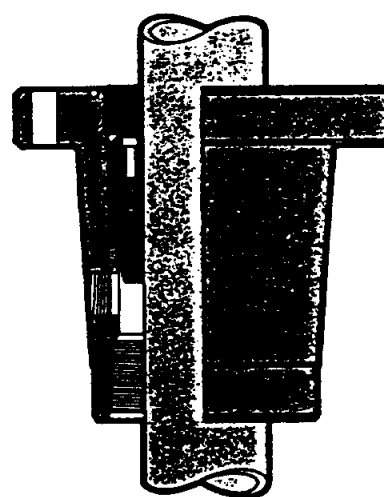
Starting Head



Casing Slips



WF Casing Head with Welded-On Landing Base



Starting Head (Threaded)

# **WELLHEAD COMPONENTS** (Reproduced with permission of Cooper Oil Tools, Houston, Texas)

### **Part 3. MUDLINE SUSPENSION SYSTEMS - (MLSS)**

A mudline suspension system provides an alternative to the surface wellhead for the support and sealing of intermediate casing strings. As the name suggests the suspension system is located at the mudline or seabed and sits within the conductor pipe rather than on top of the conductor as is the case with the surface wellhead.

The sketch opposite shows a simplified layout of a MLSS, typical of the type installed by bottom mounted drilling rigs or jack-ups. Before continuing with the description of the various components it would be beneficial to recap on how the conductor and intermediate casing strings are formed.

The conductor and casings are assembled from 9 metre (30 foot) lengths of pipe which have externally threaded ends. They are joined together and sealed against oil/gas pressure by internally threaded tubular couplings or "joints". The MLSS employs special joints which incorporate a casing hanger that screws into the casing string as it is lowered into the hole.

The assembly process commences with the installation of the conductor. A joint containing a landing face is screwed into the conductor at a position that will coincide with the mud line. The first intermediate casing will locate or "hang off" this protrusion and each subsequent casing string will be supported in a similar fashion, that is "hung off" the preceding intermediate casing hanger joint. Some designs of MLSS employ a sprung loaded, expanding casing hanger which latches into the preceding casing to provide additional support.

The MLSS has two main applications.

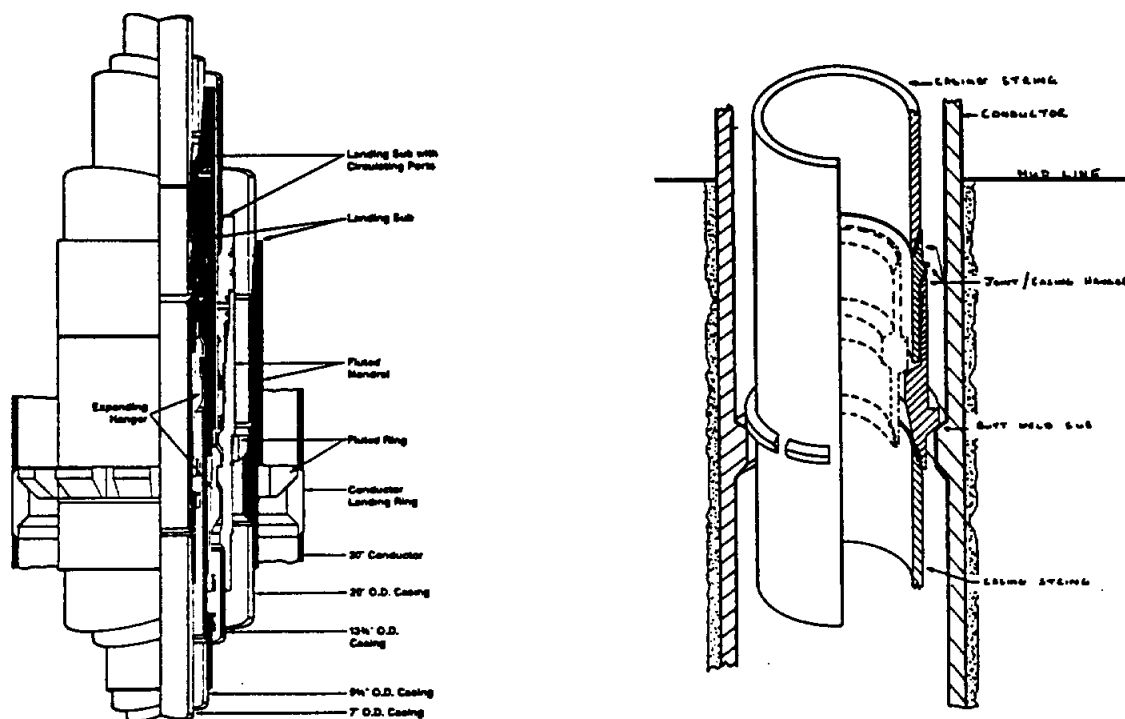
#### **i) PRE-DRILLING OF WELLS**

The drilling of wells for a production installation is a particularly time consuming operation. A considerable saving in time and hence money, can be achieved by drilling the wells prior to the arrival of the permanent installation and the design of the MLSS is ideally suited to this application.

On completion of drilling, plugs are set in the well and the conductor and intermediate casing strings which extend from the seabed to the drill floor are removed. They are simply unscrewed from the casing hanger and replaced with threaded abandonment caps. The process is reversed when the permanent installation arrives and the wells are required for production.

#### **ii) SUBSEA WELLS**

Subsea wells are drilled in an identical manner to surface wells. However, the absence of a fixed structure to support a conventional wellhead necessitates the use of either a MLSS or subsea wellhead, both arrangements sharing the same basic installation concepts. As in the previous example, on completion of drilling, the casing strings extending from the casing hanger to the drill floor are removed and replaced with a location device which will accommodate the subsea christmas tree.



### MUDLINE SUSPENSION SYSTEM

(Reproduced with permission of Cooper Oil Tools, Houston, Texas)

## Part 4. MUDLINE SAFETY VALVE

The mudline safety valve (MLSV), or to give it its correct title the surface controlled sub-surface safety valve (SCSSV), is located in the production tubing at a depth of 60 to 90 metres (200 to 300 feet) below the surface of the sea bed. It provides a last ditch barrier to isolate the well should the installation be destroyed by an explosion or collision with a ship. The valve is fail safe in operation.

The most graphic example of MLSV operation was provided when the Piper Alpha installation was destroyed by fire and explosion in July 1988. The mudline safety valves on all 36 wells closed satisfactorily, but unfortunately two of the wells provided fuel for the fire via leaks in the annulus spaces, the isolation of which ultimately required the attention of Red Adair's specialist fire fighting team.

The valves should be checked for leakage on a regular basis, preferably monthly. This entails closing the valve and depressurising the production tubing up to the christmas tree. The production tubing should remain free of any significant pressure build up for a period of 10 minutes. Should the valve fail the test it should be replaced immediately.

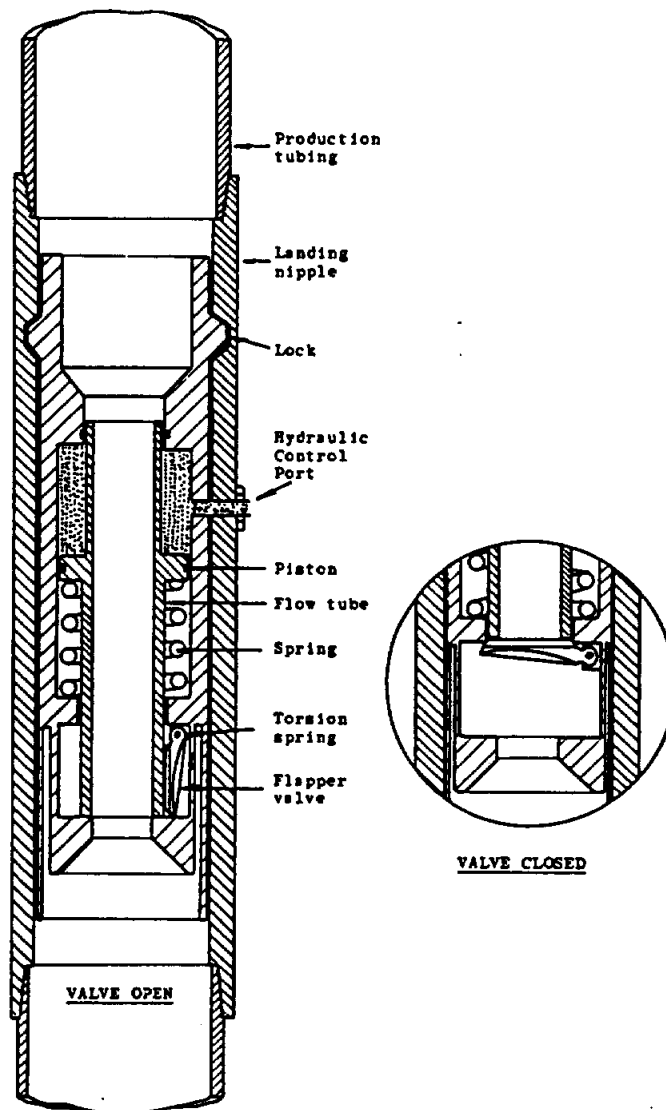
The actual valve which may be of ball, but more probably a flapper type is located in a tubular housing. The housing design determines the method by which it is installed in the production tubing, that is, it may be tubing retrievable or wireline retrievable.

- i) The tubing retrievable MLSV is screwed into the production tubing as a joint when the tubing is run (installed). Replacement involves a workover and pulling (removal) of the production tubing, a costly and time consuming exercise.

- ii) The wireline retrievable MLSV can be recovered, as the name suggests, by a wireline operation. These valves are often preferred for the ease in which replacement can be effected. The production tubing is fitted with a machined recess or landing nipple in which the MLSV is located and latched into position using a wireline tool string. The disadvantage of the wireline retrievable MLSV is that it restricts the through-put of the production tubing.

**MLSV Operation** – The sketches below show the operation of a flapper type wireline retrievable subsurface safety valve. Hydraulic oil pressure is required to keep the valve open against spring pressure. The hydraulic oil is normally supplied via a stainless steel instrument pipe routed through the well-head although some of the older installations achieved the same result by pressurising the annulus space.

All hydraulic signals to the MLSV are controlled from the wellhead skid. The valve will operate automatically via the ESD system or rupture of the fire loop. The valve can also be operated manually from the wellhead skid or from ESD push buttons located at strategic points around the installation.



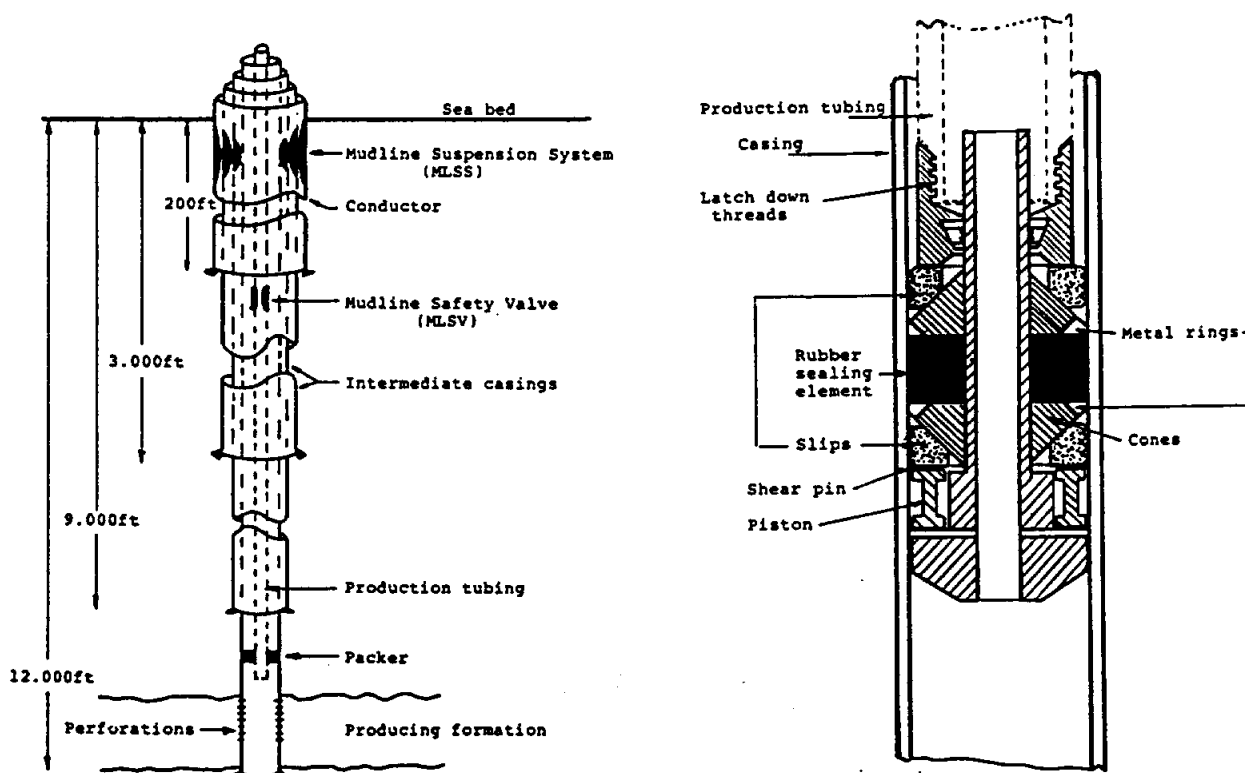
**MUDLINE SAFETY VALVE**

## Part 5. THE PRODUCTION PACKER

The function of the production packer is to seal the base of the production tubing into the intermediate casing string. Both permanent and temporary packers are available but the permanent type are generally preferred for their more reliable operation over prolonged periods.

The sketch below has been prepared to assist in the explanation of the mode of operation of a permanent packer. It should be noted that the packer is installed prior to perforation of the casing or liner so the well is full of well preservation fluid and devoid of all hydrocarbon pressure.

A packer can be run (inserted) as part of the production tubing or installed on a wireline tool string. Once in position the seals are activated by a mechanical tool, or by hydraulic pressure depending on design. The sketch shows a hydraulic packer and to activate the seals a steel blanking plug must first be set in the production tubing below the packer. The tubing is then pressurised in order to energise the setting piston which moves upwards snapping the shear pin and compressing the rubber sealing element. When the pressure is released the steel slips bite into the intermediate casing and prevent re-expansion of the sealing element. The packer is thus permanently set and should removal be required it must be drilled out, a major operation.



TYPICAL CASING ARRANGEMENT

PRODUCTION PACKER



## **Part 6. EMERGENCY SHUTDOWN SYSTEM (ESD)**

The emergency shutdown system is a name given to control equipment which is installed for the purpose of shutting down the production process and venting it to atmosphere in order to reduce the onboard hazard. The ESD system should operate automatically and independently of all other control and monitoring systems. It should also be possible to initiate an ESD from manual push buttons located at strategic positions on the installation, such as the control room, wellheads, helideck and lifeboat stations. Most modern installations also have the facility to activate the ESD system via the telemetry system.

The principal aim of the ESD system is to protect personnel, plant and equipment and minimize the risk of environmental pollution from the production process.

The design of the ESD system will vary from platform to platform depending on equipment complexity and production requirements. Hence an installation with a compression facility will have a more complex system than a basic oil or gas producing satellite platform.

The ESD system operates selectively in stages but these final events must occur.

- (1) Shutdown of all production and associated test facilities.
- (2) Closure of all wellhead valves.
- (3) Opening of all blowdown (vent) valves.
- (4) Closure of mudline safety valves.

The number of shutdown stages will vary from platform to platform as will the cause and effect philosophy. There are general guidance notes available to the industry but the ESD system philosophy is normally specific to a particular company.

A typical ESD system would operate on three levels of shutdown.

### **1. UNIT SHUTDOWN**

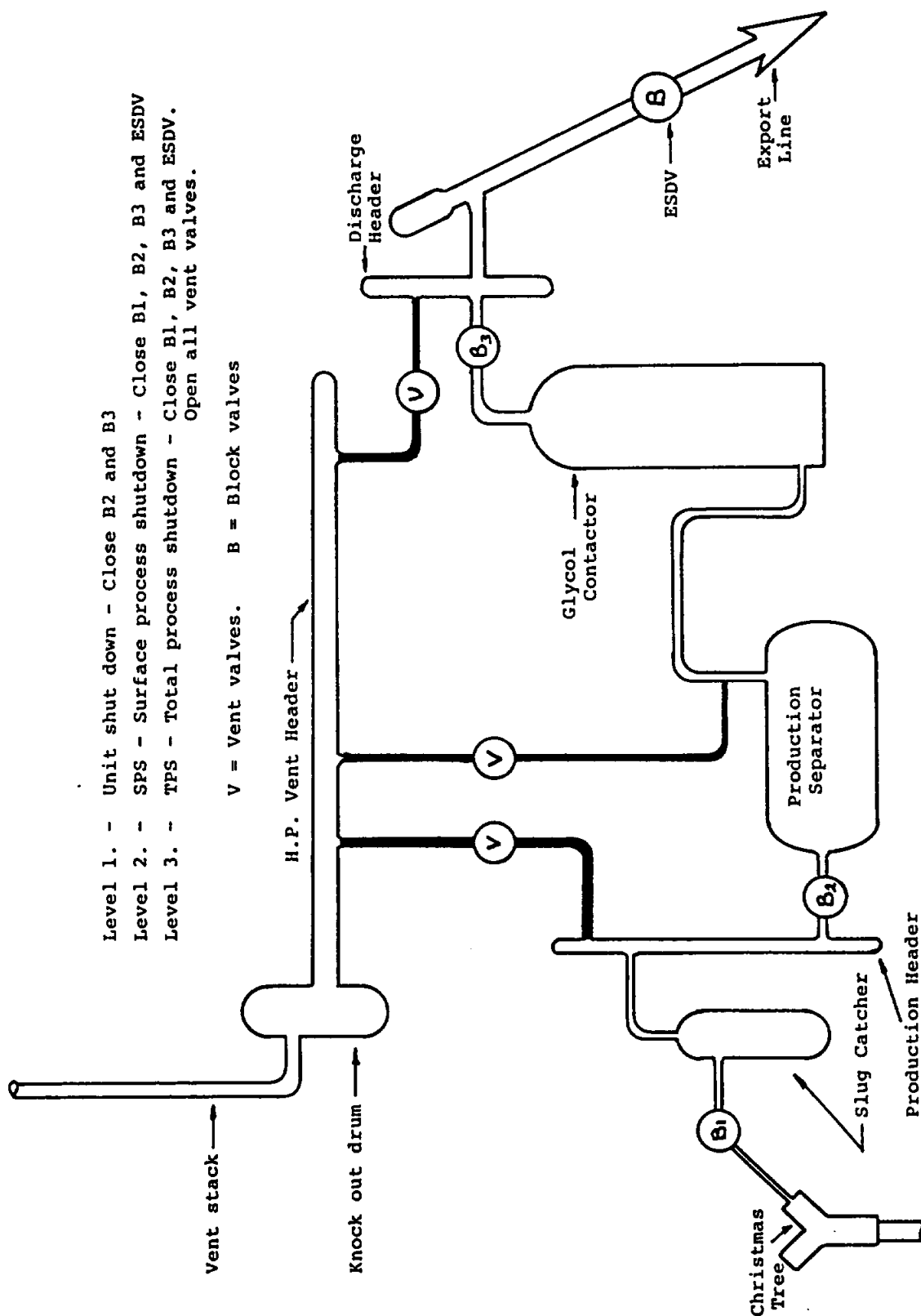
This shuts down individual process and utility systems and may be initiated manually and/or automatically. It gives the operator a chance to take corrective action prior to losing all production.

A unit shutdown can occur due to an internal trip caused by an event such as a flame failure on a glycol reboiler or by activation of a fire/gas signal (25% LEL gas).

### **2. SURFACE PROCESS SHUTDOWN (SPS)**

All process and chemical injection systems will shutdown on an SPS but utilities such as main power generation remain available. It can be initiated automatically, manually and via telemetry but does not vent the process equipment.

An SPS can be initiated by disturbances such as a high level gas alarm (50% lower explosive limit - LEL) main power generation failure, high/low export line pressure.



SCHEMATIC - EMERGENCY SHUT DOWN SYSTEM (shows only one train)

### 3. TOTAL PLATFORM SHUTDOWN (TPS)

All platform process and utility systems are shutdown on a TPS. Wellheads and mudline safety valves close and main power generation shuts down (emergency power generator will normally still run). The blowdown valves open and the platform is depressured.

A TPS is normally initiated from a fire signal (heat detector or combination of U/V detectors).

As a further safety precaution a pneumatic fire loop is often included in the ESD system. This can either be a stainless steel instrument piping loop fitted with fusible plugs or it may simply consist of a small bore plastic pipe. The loop extends throughout the wellhead and process areas and is pressured to 3.5 to 7.0 bar (50-100 psi.). Should a fire occur, the fusible plugs or plastic pipe will melt and release the air pressure. This will then activate the ESD system via an electrical, pneumatic or hydraulic solenoid.

### GUIDANCE NOTES ON ESD SYSTEMS

1. A.P.I. Spec. RP 14.G. Basic surface safety systems for Offshore Production Installations.
2. Technical requirements for E.S.D. systems for Offshore Installations by I. Turner of Lloyd's Register of Shipping (paper commissioned by UK Department of Energy in 1982 and prepared by Det Norske Veritas and Lloyd's Register of Shipping).

### EMERGENCY PIPE-LINE VALVE REGULATIONS SI NO. 1989/1029

As a result of the explosion and eventual destruction of the Piper Alpha installation on 6th July 1988, which claimed 167 lives, the Government passed the Offshore Installations (Emergency Pipeline Valve) Regulations 1989 (SI 1989 No. 1029). The Department of Energy publish comprehensive guidance notes to assist in the interpretation of the regulations.

Basically the regulations require that all fixed pipelines bringing toxic or flammable substances on to, or off a platform be fitted with an emergency shutdown valve (ESDV).

The ESDV must be of a fail safe design which will operate automatically on signals generated by the ESD system. The valve must be protected from damage arising from fire, explosion or impact from dropped objects.

The ESDV should be located below the lowest deck and as far down the pipeline riser as is practicable whilst still being above the highest anticipated wave crest and available for maintenance.

These regulations were considered necessary due to the fact that many offshore installations share a common subsea pipeline for the conveyance of their products to a reception facility on the mainland. The ESDV is designed to isolate an installation should an emergency situation, such as a fire develop. Hopefully this will prevent a re-occurrence of the Piper Alpha disaster where the initial fire was fuelled by oil and gas pumped in by adjoining platforms.

The SI 1029 lays down strict rules to ensure that regular maintenance and tests of the ESDV's are carried out and officially recorded.



# Chapter Nine

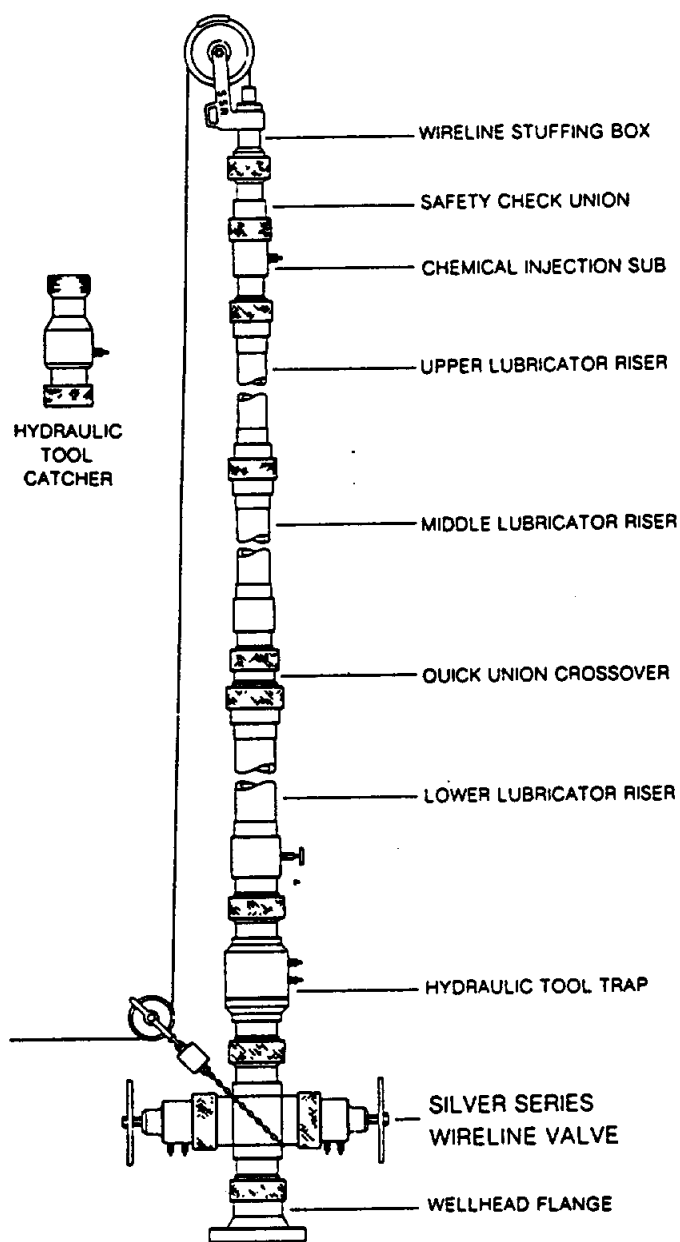
## WELL MAINTENANCE

### Part 1. WIRELINE

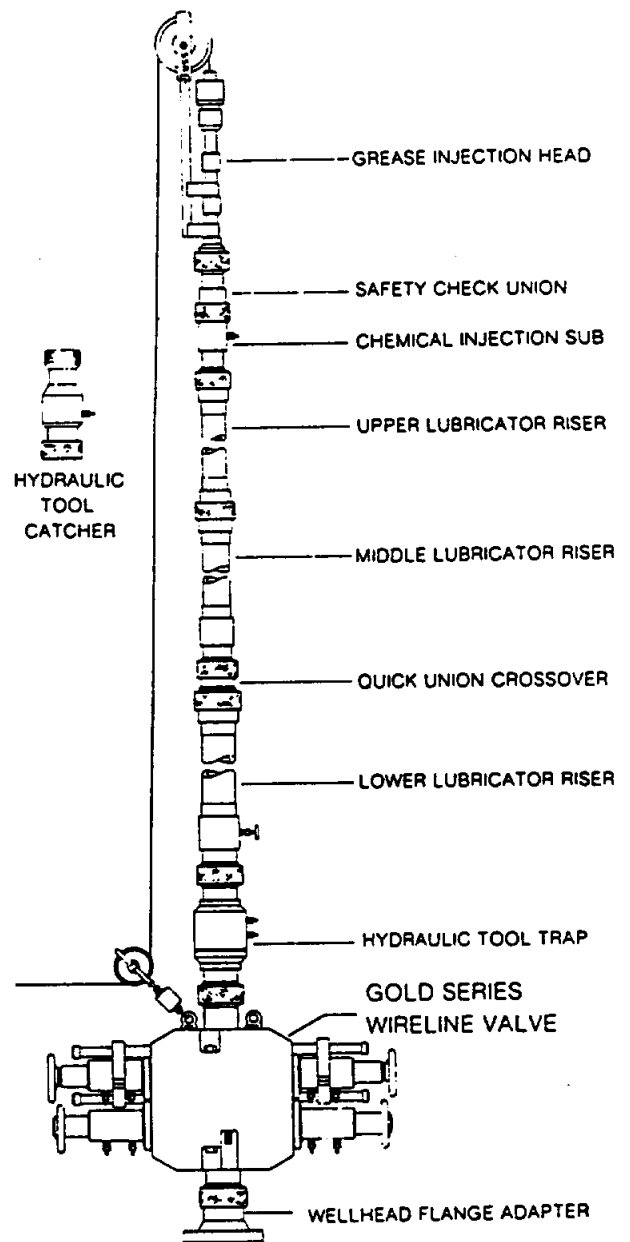
1. Wireline Equipment.
2. Wireline Tool String.
3. Wireline Operations.

### Part 2. WORKOVER OPERATIONS

1. Well Stimulation.
2. Well Modifications.



**SLICK LINE LUBRICATOR STACK**



**WIRE LUBRICATOR STACK**

(Courtesy of SSR (Int.) Ltd)

## Part 1. WIRELINE OPERATIONS

Wireline equipment has been in use since the early days of the oil and gas industry. It permits mechanical devices to be installed or removed in the production tubing with minimal interruption to the production process.

The equipment is attached (flanged or screwed) to the top of the christmas tree as shown in the sketch. Various wireline tools can then be attached to the wire and lowered through the christmas tree swab valve and into the production tubing.

Most operations can be carried out using a single strand wire or slick line (also called piano or music wire) which is available in thicknesses ranging from 0.066 to 5/16 inch (1.65mm to 8.0mm) and supplied in lengths of 10,000 to 40,000 feet (3,030 to 12,120 metres). However, when a stronger line is required a braided wire of 3/16" to 5/16" (4.75mm to 8.0mm) diameter is normally used (often called torpedo or well shooters line). An electric line may also be used as an alternative to the simple wireline. The electric line facilitates the passage of electrical signals and permits the use of more sophisticated equipment. The electric line can even be used to operate a video camera which may be lowered into the well and used to identify leaks and blockages in the production tubing.

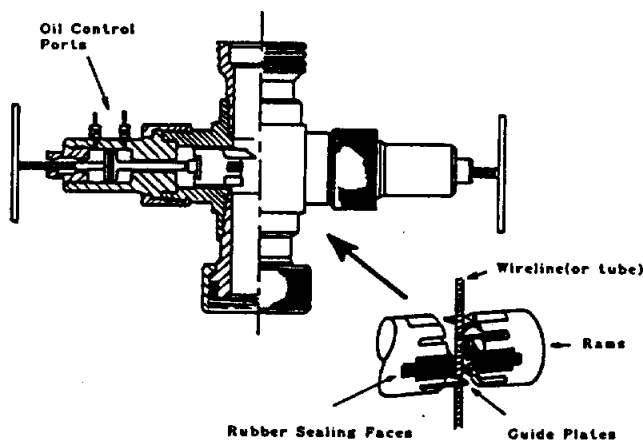
The wire is wound around a drum which is powered by a diesel driven hydraulic pump. Hydraulic equipment is preferred on the grounds of safety for use in a hazardous area.

### 1. WIRELINE EQUIPMENT

The wireline assembly shown opposite contains the following items of equipment:-

#### i) WIRELINE VALVE OR BLOWOUT PREVENTER (BOP)

The wireline valve lies at the heart of the wireline operation. It enables quick and safe isolation of well pressure from the lubricator sections mounted above it. The valve is often referred to as a BOP (blowout preventer), somewhat of a misnomer as a blowout can only occur during drilling operations. However, the wireline valve is basically a smaller brother of the drilling BOP being almost identical in design and operation so the confusion is understandable.



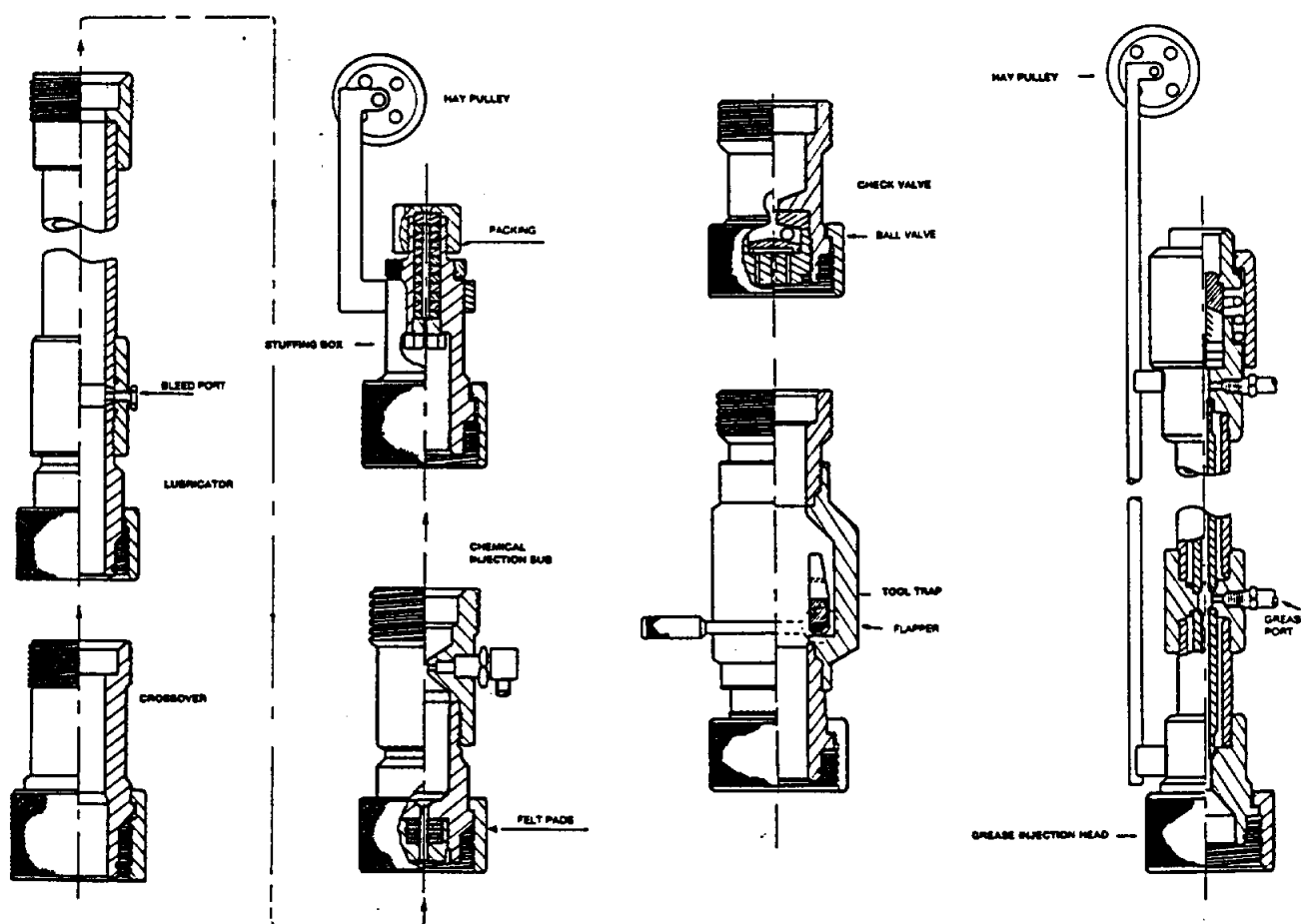
COIL TUBING/WIRELINE VALVE

In its simplest form the wireline valve consists of a pair of rams fitted with rubber inserts which can be manually wound in to close and seal around the wire, thus sealing the production tubing.

A more sophisticated version is available which employs two pairs of hydraulically operated rams. The top rams are fitted with rubber inserts for sealing on the wire and the lower blind rams are designed to shut off well pressure should the wire become detached from the winch drum. The wireline valve is attached to the christmas tree at the swab connection. A crossover may be required between the two to compensate for diameter, flange or thread variations.

During wireline operations on a producing well the tree should remain connected to the emergency shutdown (ESD) system. This ensures that should an emergency situation develop, the christmas tree master valve will close and cut through the wire line. The wire, complete with tools, will drop into the well thus allowing the mudline safety valve to close.

The master valve on older christmas trees may not be designed to cut wires. Where this situation occurs a fail safe wireline cutting gate valve should be installed between the wireline valve and the christmas tree and connected into the platform's ESD system.



WIRELINE STACK COMPONENTS



**ii) LUBRICATOR OR RISER**

The name "lubricator" is misleading as no lubrication actually takes place within this component. It consists of a length of pipe, approximately 8 to 10 feet (2.4 to 3.0 metres) in length and of a diameter to suit a particular tool string, normally 3.1/2 to 5.1/2 inches (90 to 140 mm). It is fitted with male (pin) and female (box) unions (screwed or welded) at each end to permit ease of assembly. Several sections of lubricator may be joined together to give the necessary height above the wireline valve to facilitate the entry of the tool string.

**iii) STUFFING BOX and CHECK VALVE UNION**

The stuffing box is a simple device attached to the top section of lubricator whose function is to seal the wire against gas pressure. The tubular body is filled with layers of packing and may incorporate a plunger or ball valve designed to shut off gas pressure should the packing become damaged, or the wire break. In the absence of a plunger or ball valve a separate check valve union will be mounted below the stuffing box.

**iv) HAY PULLEY**

The hay pulley is attached to the top of the stuffing box, its function being to redirect the wire to the winch drum.

**v) GREASE INJECTION HEAD or H.G.T. (high pressure grease tube)**

The grease injection head is used in place of the stuffing box when braided wire is used in preference to a single strand wire. Grease is pumped through the injection head at a pressure approximately 500 psig (35 bar) above the gas pressure to seal and lubricate the wire.

**vi) TOOL TRAP**

The wireline winch drum is fitted with a counter to enable the operator to determine the depth of the tool string. However, there is always the risk of stripping the wire from the rope socket as it is winched into the stuffing box and to prevent the tool string from dropping back into the well, a tool catcher may be fitted. Mechanical and hydraulic tool traps are available, some of which latch onto the rope socket under wireline tension and some which close under the tool string as it is raised into the lubricator assembly. The location of the tool trap in the lubricator stack will depend on the design.

**vii) CHEMICAL INJECTION SUB**

The chemical injection sub provides the means by which chemicals may be applied to the wireline. The chemicals are introduced into the sub assembly at a side port and are absorbed by replaceable felt pads which wipe the wire as it enters and leaves the well. Methanol is frequently used to combat icing whilst corrosion inhibitors provide the wire with some protection against hydrocarbon products produced from sour reservoirs.

## **2. WIRELINE TOOL STRING**

The sketch shows a typical wireline tool string arrangement. The wire rope socket, jars and knuckle joint are present during all wireline operations and special tools are added to the basic string depending on the task in hand.

The wire is fed through the stuffing box and lubricator prior to addition of the tool string and the complete assembly is then mounted on top of the wireline valve. The wireline toolstring is then lowered through the christmas tree swab valve, master valve or valves and into the production tubing.

The components of a tool string may be described as follows:-

### **i) WIRE ROPE SOCKET**

This device joins the tool string to the wire. The wire is threaded through the body and around a plug which is then pulled into a taper. Slip rope sockets are a variation on this basic theme and are designed to break at 50%, 60%, 70%, 80% or 90% of the wires tensile strength should the tool string become jammed. Failure of the wire simplifies tool string retrieval, the rope socket being designed to facilitate the attachment of a latching recovery tool.

### **ii) JARS**

The simplest form of jar is a heavy length of tube and various weights are available. They are used to 'jar' free tools stuck in the tubing (as in the previous case describing the rope socket) and to provide extra weight to assist latching operations.

Mechanical jars can only be used to jar in a downward direction. Hydraulic jars are required for jarring in an upward direction. Their operation is self explanatory.

### **iii) KNUCKLE JOINT**

The knuckle joint contains a ball and socket which provides flexibility within the tool string.

### **iv) WEIGHT BARS**

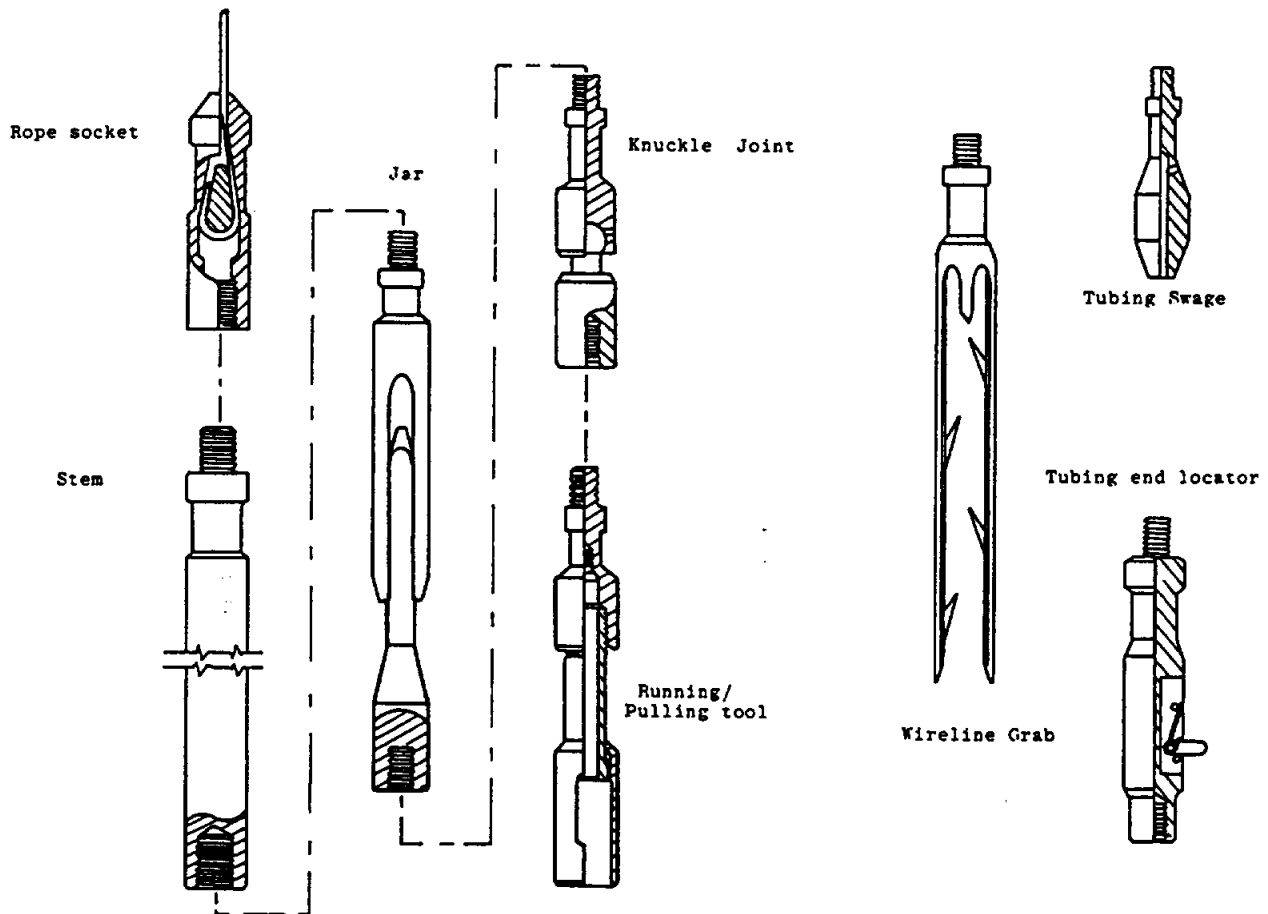
Weights are used to increase the effectiveness of jars and weigh from 5 to 33 pounds (2.25 to 15 kilogrammes).

### **v) PULLING/RUNNING TOOLS**

Pulling refers to the removal of a device such as a mud-line safety valve or pressure test plug from the production tubing. The installation process is known as running a tool and relies on a latching mechanism for emplacement.

## **3. WIRELINE OPERATIONS**

A multitude of operations can be carried out using wireline equipment and four of the basic tasks will now be described.



## WIRELINE TOOL STRING

## SELECTION OF TOOLS

### i) PERFORATING

Perforating is carried out on a new well prior to bringing it into service and on existing wells which have been subjected to modifications in the vicinity of the hydrocarbon bearing formation or pay zone. It is a wireline process by which a string of explosive charges is lowered through the production tubing to the depth at which the gas or oil producing formation exists. When the explosive charges are detonated the concentrated blast punches holes through the casing, and into the formation. The numerous small holes produced permit hydrocarbons to flow into the production tubing and up to the rig. The casing may be perforated over a distance of several hundred feet.

## ii) LOCATION PLUGS AND VALVES

Two of the more frequent operations carried out using wireline equipment are the change out of wireline retrievable mudline safety valves (MLSV or SCSSV) and to a lesser extent the fitting of plugs in the production tubing.

The production tubing is the innermost tubing string in the well through which hydrocarbon products are conveyed from the pay zone to the christmas tree. As the tubing is installed it is fitted with a number of landing nipples (shouldered joints) set at different depths which are designed to accommodate the mudline safety valve (MLSV), and on occasions, steel blanking plugs. The blanking plugs permit pressure tests to be carried out on the production tubing when searching for leaks, and provide the means by which the well can be isolated prior to changing a christmas tree.

The installation of MLSV's is a straightforward wireline operation. They are attached to a suitable running tool and latched in to the landing nipple, a pulling tool being used to separate the latch prior to removal.

## iii) FORMATION SURVEYS

- a. **Bottom hole surveys.** An accurate assessment of the condition of a production well can be made by lowering self-contained pressure and temperature sensing devices in to the hydrocarbon bearing formation on the end of a wireline tool string. The data obtained enables the reservoir engineers to determine whether or not the well is producing at its maximum potential.
- b. **Logging.** During drilling operations the hydrocarbon bearing potential of the formation can be determined by "logging" the hole using electric wireline operated tools. A log is a record of readings generated by a logging tool which transmits electric, sonic or radioactive signals into the formation. The return signals are computer analysed and a profile of the logged zone developed. Subsurface formations possess certain measurable characteristics which help to identify the type of rock structure and the hydrocarbon content.

## iv) WELL MAINTENANCE

Typical operations are cleaning the production tubing of wax, clearing blockages with a swage and removing sand. Special tools have been developed for each of these operations as shown in the sketches.

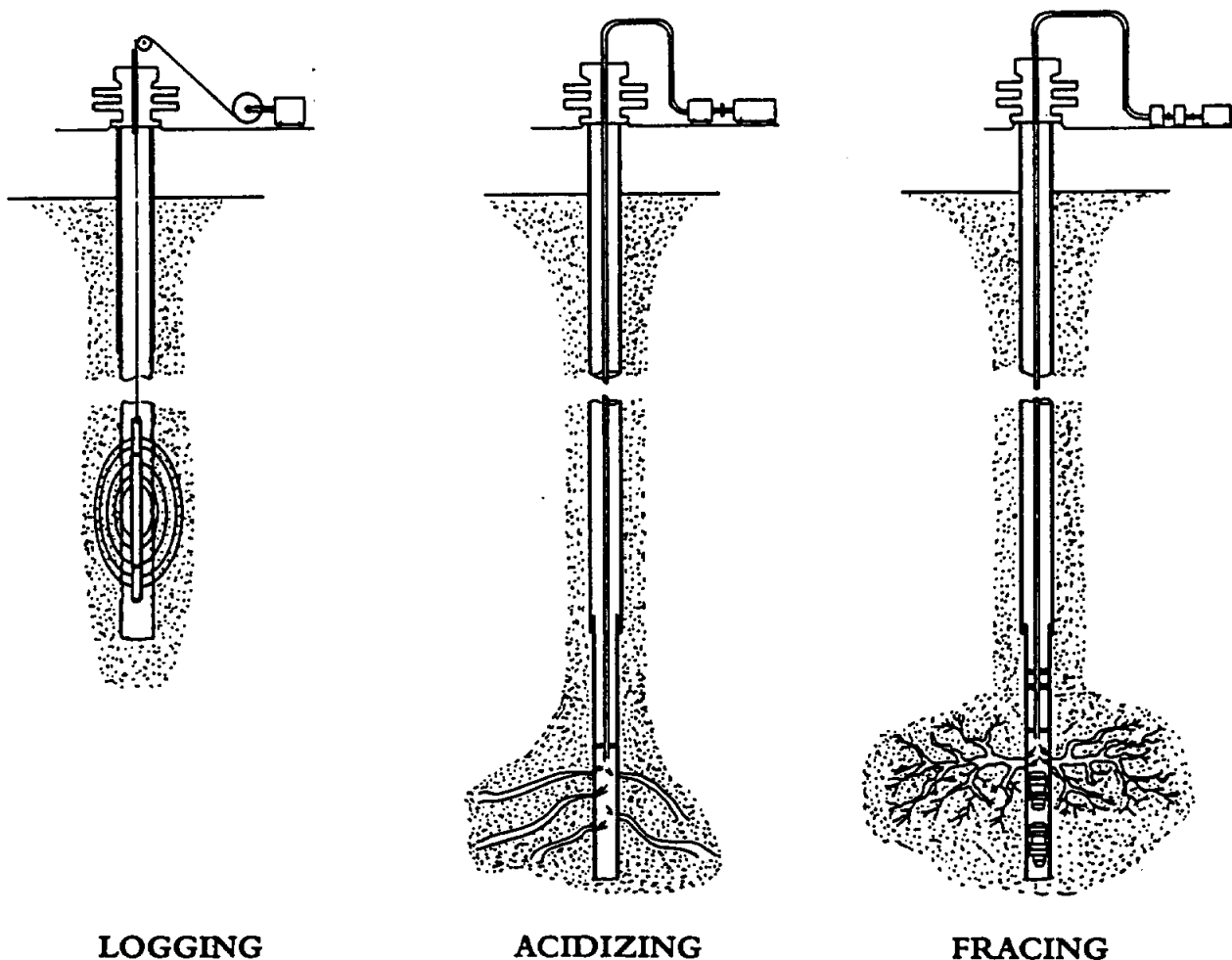
There is also a fishing tool for recovering broken wires. The term "fishing" may also be used to describe the process of latching onto MLSV's or plugs prior to their removal.

## PART 2 WORKOVER OPERATIONS

During the life of a well, which maybe 25 years or more, situations inevitably arise which call for the modification or repair of equipment associated with the production tubing. Mechanical problems such as leaks in packers, tubing joints and cement seals develop and the depletion of hydrocarbons may result in changes in reservoir conditions which can restrict output, typically caused by the build up of sand. These problems can be corrected by suspending production on the affected well and carrying out a "workover job". Workovers involve the use of highly sophisticated equipment normally supplied by contractors who specialize in a particular field of operations. They may be loosely divided into two categories, that is workovers which deal with the rectification of defects in the production tubing and casing, and workovers designed to improve or stimulate the hydrocarbon bearing formation in the vicinity of the well bore.

### 1. WELL STIMULATION

Three of the more common well stimulation processes may be carried out using containerised equipment temporarily located on the platform, or from purpose built well stimulation ships, depending on the size of the task in hand, the operations involving the injection of gases (nitrogen) or liquids (acids)



into the well through coil tubing equipment. The equipment is mounted above the christmas tree and outwardly resembles the wireline valve and lubricator stack used for wireline operations. However, it is a one inch (25mm) diameter steel tube that passes through a coil tubing BOP into the christmas tree and on into the well and not a wireline tool string. The inherent flexibility of the tubing enables it to be coiled around a large drum when not in use, hence the derivation of the expression coil tubing.

**i) FRACTURING (FRACING)**

Fracturing is used to improve the flow of hydrocarbons into the well bore. It involves the injection of oil or water based fluids at very high pressures into the rock formation. This induces cracks and opens fissures thus enlarging and extending the drainage area.

Sand, or artificially manufactured proppants may be injected with the fracture fluid so that when the hydraulic pressure is released, the solid particles will remain in place holding the fissures apart as the liquid drains away.

**ii) ACIDIZING**

Acid can be used to remove damage near the well bore in sandstone and carbonate formations and to produce long linear flow channels away from the well.

Matrix acidizing involves injecting acid below fracture pressure to dissolve deposits restricting the perforations.

Fracture acidizing involves injecting acid at a pressure greater than fracture pressure. The acid forces the fracture line apart and dissolves a flow path which remains when the fluid pressure subsides and the fracture closes once more.

Additives are mixed with acid solution to prevent the corrosion of steel and the formation of sludges which could block the tubing perforations.

**iii) SAND CONTROL**

Sand can congregate at the well base and block the perforations. Small quantities can be scooped out using wireline equipment but where large quantities exist more drastic action is required.

A popular solution is to install a slotted screen in the open hole, or in the casing. Gravel packed around the outside of the screen will permit the passage of hydrocarbons whilst hindering the passage of sand.

Another solution involves the precipitation of resin between the sand grains in order to bond them together and prevent the flow and further accumulation of sand.

## **2. WELL MODIFICATIONS**

The removal of the production tubing is a major operation requiring the use of the drilling derrick, or a mobile workover rig. Problems which necessitate the removal of the production tubing tend to be fairly serious in nature and for safety reasons the well must be killed before work commences. This can be done most effectively by displacing the contents of the production tubing with brine in order to

overbalance the formation pressure. With the well thus suitably killed the christmas tree can be removed, replaced with a BOP stack and the work can proceed.

These are some of the more basic well workover operations.

### i) PRODUCTION TUBING DAMAGE

The production tubing is exposed to the full force of reservoir pressure and all the associated contaminants which accompany the hydrocarbons such as formation acids and abrasive sands. Consequently it is not unusual for problems to develop as the well ages and leaks occasionally occur which require the replacement of all, or at least part, of the production tubing.

### ii) MUD-LINE SAFETY VALVE REPLACEMENT

Mudline safety valves may be of the wireline retrievable, or tubing retrievable type. As the name suggests the tubing retrievable valves require the removal of the production tubing in order to facilitate their replacement. Whilst the mudline safety valves tend to be very reliable in operation it is unlikely that they will see out the life of a well. As the valve is located only 30 metres (100 feet) below the sea bed replacement of the MLSV does not necessitate the removal of the entire production tubing but it is still quite a considerable task.

### iii) PRODUCTION TUBING REPLACEMENT

As the reservoir ages it is common practice to replace the production tubing with one of a smaller diameter in order to increase the velocity of well fluids. This ensures that impurities such as water and sand are brought to the surface where they can be separated and disposed of by the process plant rather than risk their accumulation in the production tubing which will eventually kill (block) the well.

### iv) PACKER REPLACEMENT

Quite a common problem which afflicts older wells is leakage of the packer which seals the production tubing into the inner most casing string. The remedy involves the removal of the production tubing so that the defective packer can be machined out. This is achieved using a milling cutter on the end of a drill string. With the casing suitably cleaned and all drilling debris removed the production tubing can be replaced and a new packer activated.

### v) CEMENT SQUEEZE

Occasionally leaks develop in the production casing string joints, or where corrosion has taken place. This may manifest itself as a reduction in well output as reservoir products are lost from the well into the formation, or it may be indicated by increased water production when water seeps from the formation into the well. Again the solution necessitates the removal of the production tubing in order to isolate the damaged casing with blanking plugs. Cement is then pumped under pressure between the plugs from whence it is squeezed out through the leak zone where it will set to form a permanent repair. A similar procedure is used for blanking off redundant perforations.

### vi) EOR EQUIPMENT

Some enhanced oil recovery aids such as deepwell pumps and gas lift equipment are installed or run with the production tubing. Therefore any repairs or modifications will involve removal of the production tubing and a workover.





# Appendices

## APPENDIX I - STRUCTURAL STEEL

It is beyond the scope of this book to enter into a discussion on the design of an offshore installation and historically the only readily available publication on the subject is produced by the American Petroleum Institute, API RP 2A - Recommended Practice for Planning, Design and Construction of Fixed Offshore Platforms. However, having established a suitable design the structure must be constructed in accordance with the requirements of a recognised specification.

Traditionally structures have been constructed to the American Welding Society's AWS D1.1 - Structural Welding Code. In common with the majority of engineering reference books which originate in the USA, AWS D1.1 provides a wealth of information on all aspects of welding (including weld procedures and welder qualification tests) and includes guidance on the selection of materials, workmanship, inspection and non-destructive examinations.

More recently in Europe, the Engineering Equipment and Material Users Association have developed a standard aimed specifically at the North Sea, namely EEMUA 158, Construction of Fixed Offshore Installations in the North Sea. The EEMUA 158 defines the basic requirements for fabrication work on primary structures whilst recommending that steel work other than primary be fabricated in accordance with AWS D1.1

If not referenced specifically, EEMUA 158 and AWS D1.1 will almost certainly provide the basis from which company specific structural construction specifications are prepared and as such will be encountered repeatedly on new building, repair and modification projects.

### 1. STRUCTURAL STEELWORK

The component parts of the jacket and topside support framework of an offshore installation are categorised as either primary or secondary structure and the steels used for construction are similarly identified as primary and secondary steels.

#### i) PRIMARY STRUCTURE

Primary structural members are those which contribute to the overall integrity of the installation and include such items as jacket legs, piles, braces, columns and beams. Where these components are subjected to significant tensile loads they must be constructed from steels with guaranteed through thickness properties and are often classed as "Special Structural" primary steels, examples of which are nodes and pad eyes/ears.

#### ii) SECONDARY STRUCTURE

Secondary structural members can be described as those components whose contribution to the integrity of the structure as a whole is not significant and includes items such as deck stringers, crane pedestal supports and stairways. Failure of a secondary structural member is unlikely to affect the overall integrity of the installation.

Some of the more readily identifiable structural components are:-

**Can** - Large cylinder formed from rolled plate and welded end to end to construct jacket legs.

**Bracing** - Tubular support member arranged to provide stiffening to the jacket legs. May be manufactured from cans or seamless or welded pipe depending on the diameter required.

**Node** - Intersection of bracings. May be welded or cast with cast steel components preferred for modern deep water jackets.

**Plate girder** - "I" section beam manufactured from steel plate and used as deck support. Normally referred to as a PG.

**Pad eye/ear** - Fabricated or cast steel bracket through which (eye) or around which (ear) wires are attached for the lifting of the module during installation.

## **2. MATERIAL SPECIFICATIONS**

Structural steels used for the construction of offshore installations will normally comply with one of four specifications.

### **i) BRITISH STANDARD 4360 - WELDABLE STRUCTURAL STEELS**

The B.S. 4360 is used extensively in the U.K. and abroad for the manufacture of structural steels with properties suitable for use Offshore. More recently it has been adapted to provide the basis of a Euro Standard specific to offshore structures, EEMUA No. 150.

### **ii) EEMUA NO. 150 - STEEL SPECIFICATION FOR OFFSHORE STRUCTURES**

The major European purchasers of engineering products have formed an organisation known as EEMUA, Engineering Equipment and Material Users Association. The EEMUA No. 150 specifies parameters for the selection of structural steels and provides comparison tables for British, European and American material grades.

### **iii) ASTM - AMERICAN SOCIETY FOR TESTING AND MATERIALS**

The ASTM Organisation provide a range of specifications covering low strength carbon steels through to high strength low alloy steels, most of which are suitable for offshore structures.

### **iv) API SPEC. 5L - LINE PIPE**

Whilst Spec. 5L pipes are manufactured primarily for pipeline service, they are also used extensively as jacket bracings. The project fabrication specification must be studied to confirm the suitability of the materials and establish if any additional mechanical tests are required prior to use.

The specifications listed above contain numerous grades of steel which may be compared firstly by tensile strength, secondly by yield strength and thirdly by impact (charpy) properties. The materials are generally referenced using a number to indicate tensile or yield strength and a letter to give an indication as to the resistance to brittle fracture. For example EEMUA 355D has a minimum yield strength of 355 N/mm<sup>2</sup> with impact values recorded at -20°C.

## APPENDICES

In order to simplify the selection of steels for a particular project the fabricator or client may tabulate materials into groups or types depending on their application. The numbering system employed has not been standardised so the previously mentioned EEMUA 355D may be listed as a type 2 material by one fabricator whilst a competitor lists it as a type 4. To avoid confusion all materials should be selected in accordance with the requirements listed by the latest revision of the fabrication specification specific to the project in hand.

## APPENDIX II - WELDING

Welding is an extremely complex subject and the preserve of the Welding Engineer. However, an appreciation of the more frequently encountered terms and specifications will prove of considerable value.

### 1. TERMINOLOGY

**QA/QC** - Quality assurance and quality control are not welding terms in themselves but wherever fabrication and welding are carried out there will almost certainly be a Quality System in evidence. A Quality Assurance System in accordance with the British Standard 5750, (or an equivalent such as ISO 9000) is required to ensure that the end product is manufactured in accordance with the specification.

**W.P.** - The purpose of the weld procedure test is to prove the compatibility of welding consumables with construction materials, to confirm the suitability of the process and equipment and to establish the parameters for items such as the geometry of the weld preparation, pre-heat/interpass temperatures and heat inputs.

On completion of welding, the test piece is subjected to both non-destructive and destructive examinations in accordance with the specification to which approval is sought. Whilst some specifications such as AWS D1.1 permit the use of pre-qualified procedures this practice tends to be frowned on by the offshore industry. The weld procedures are invariably qualified prior to commencement of construction using samples of materials and consumables that will eventually be used in production.

The American Petroleum Institute publication API Std 1104 - Standard for Welding Pipelines and Related Facilities, is a self contained reference document which deals specifically with welding procedures. It provides a step by step guide on how the tests should be conducted, tested and documented and is highly recommended reading. The AWS structural welding code is also very informative.

**WPQR** - The welding procedure qualification record exists as a permanent record of the welding procedure test and contains all the relevant information categorised as either essential or non-essential variables and the non-destructive and destructive test records.

**WPS** - The weld procedure specification is prepared from the WPQR and provides the welder with specific guidance on how to approach a particular weld. It includes information pertaining to the size and type of electrode, the number of runs and the amperage to be used. A number of WPS's may be prepared within the tolerances permitted by the WPQR to cover such items as variations in component size, thickness and material type.

**SWIS** - The site welding instruction sheet is associated with EEMUA 158 and fulfils an identical function to the WPS.

**Welder Qualification Test** - To ensure that a welder possesses the necessary skills to produce a sound weld he must complete a test piece which is representative of conditions that will be encountered during production welding. Whilst the test weld must comply with a particular WPS it will normally permit the welder to weld a considerable number of similar WPS's.

**Pre-heat** - Pre-heat is used primarily to slow the cooling rate of a welded component in order to reduce the shrinkage stresses, prevent excess hardening and loss in ductility. It also assists in the diffusion of hydrogen and thus reduces the likelihood of underbead cracking. Preheat may be applied by propane gas torch, or by the attachment of electric resistance mats. The degree of preheat is governed largely by the thickness of the material and can be calculated from the carbon equivalent formula.

Carbon Equivalent.- 
$$Ceq = \%C + \frac{\%Mn}{6} + \frac{\%Ni}{15} + \frac{\%Mo}{4} + \frac{\%Cr}{4} + \frac{\%Cu}{13}$$

The approximate temperature requirements based on carbon equivalent values are:-

up to 0.45%	preheat optional
0.45% to 0.60%	95°C to 205°C (200°F to 400°F)
0.60% and above	205°C to 370°C (400°F to 700°F)

**Interpass temperature** - In a multi-pass weld, the temperature of the weld metal prior to commencement of the next pass is referred to as the interpass temperature and it must be controlled within pre-determined limits if weld defects are to be avoided.

**Post weld heat treatment (PWHT)** - Stress relief. As the same suggests, stress relieving is carried out to reduce the stresses caused by welding and may be required when material thickness exceeds  $\frac{3}{4}$  inch (19mm). It involves heating the component to a temperature of 590°C to 650°C (1100°F to 1200°F), holding or soaking for a period of 1 hour per inch of material thickness and cooling slowly to ambient temperature. PWHT may be effected by the attachment of electric resistance heating mats or by inserting the component into a furnace.

**SMAW** - Submerged manual arc welding using conventional "stick" electrodes is the most widely used of the various arc welding processes. The stick or welding rod consists of a steel wire covered with a flux designed to decompose under the heat of the arc and generate a shielding gas which will prevent the formation of oxides and nitrides in the molten weld pool.

**SAW** - Submerged arc welding or "sub-arc" is the term used to describe an automatic or semi-automatic welding process. The welding wire is fed from a reel whilst powdered flux is poured over the weld preparation to ensure that the arc remains submerged. Metal deposition may be up to 10 times that achieved with SMAW welding. The process is only suitable for downhand (flat) welding and whilst circular components can be welded they must be rotated with the initial pass or "root run" being manually welded.

**FCAW** - Flux cored arc welding, a development of SMAW welding, can be used in all positions and exists in both automatic and semi-automatic forms. The flux is contained within the core of the welding wire which is in effect a stick electrode turned inside out. The welding wire is supplied in reels and automatically fed through a gun so that the operator can weld continuously without the inconvenience of the frequent interruptions required to change electrodes.

**GMAW** - Gas metal arc welding is a semi-automatic welding process normally referred to as MIG (metal inert gas) and mixtures of carbon dioxide, argon and helium gases are used as shielding agents in preference to a traditional flux. The gas is circulated around the welding wire which is fed from a reel. MIG welding permits high deposition rates and is used for spot welding being suitable for use on steels, alloy steels, aluminium, copper and magnesium.

**GTAW** - Gas tungsten arc welding is normally referred to as TIG (tungsten inert gas) welding and employs a non combustible tungsten electrode to create an arc whilst the filler wire is fed either manually or automatically into the molten weld pool. Protection against oxidation is provided by an argon, or argon/helium shielding gas. Steels, aluminium and copper alloys can be TIG welded and whilst a relatively slow process it is particularly well suited to the welding of small diameter pipes where root penetration must be kept to a minimum.

**Carbon air arc gouging** - Air arc gouging is frequently employed in preference to grinding for the removal of large quantities of weld metal prior to repairs or modifications to the weld preparation. The gouging process employs a carbon electrode to create an arc against the workpiece and the subsequent pool of molten metal is removed by a jet of compressed air.

**Plasma arc cutting** - This is a relatively new process which is used primarily for the cutting out of steel components from plate in the workshop. An electric arc is generated against the work piece by a tungsten electrode, the arc subsequently being fuelled by a super heated, high velocity plasma gas stream which may be a mixture of argon and hydrogen, or nitrogen and hydrogen. The process is both quicker and more accurate than oxy-acetylene cutting and the finished article may be welded without further surface preparation.

**Consumable** - The term "consumable" refers to the item consumed during the welding process namely electrodes, filler wires, fluxes and shielding gases. With the exception of the gases, consumables are generally manufactured in accordance with AWS (American Welding Society) specifications.

## **2. WELDING SPECIFICATIONS**

The standards listed below represent those which will be most frequently encountered during the construction of an offshore installation and its equipment.

### **i) BRITISH STANDARDS**

**B.S. EN 287** - Approval testing of welders for fusion welding  
(formerly BS 4871).

**B.S. EN 288** - Specification and approval of welding procedures for metallic materials  
(formerly BS 4870).

**B.S. 5135** - Metal arc welding of carbon and manganese steels.

**EEMUA 158** - Construction specification for fixed offshore structures in the North Sea.

### **ii) AMERICAN STANDARDS**

**AWS D1.1** - Structural welding code

**ANSI/ASME B31.3** - Chemical plant and petroleum refinery piping.

**ASME IX** - Boiler and pressure vessel code.

The welding of all critical components such as pressure vessels, pressure piping and structural steelwork should be supervised by suitably qualified welding inspectors and subsequently examined by similarly qualified NDT (non destructive testing) technicians.

Two universally recognised organisations which operate schemes for the assessment and certification of welding inspectors and NDT technicians are the Welding Institute in the UK and the American Society of Non-Destructive Testing (ASNT) in the USA.

The Welding Institute examine inspectors and technicians on behalf of an independent management board and issue CSWIP/PCN certificates to successful candidates. The certificates are valid for five years and are transferable from one company to another.

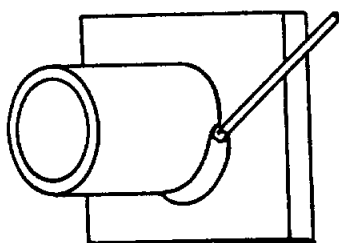
**CSWIP** - Certification scheme for weldment inspection personnel.

**PCN** - Personnel certification in non-destructive testing.

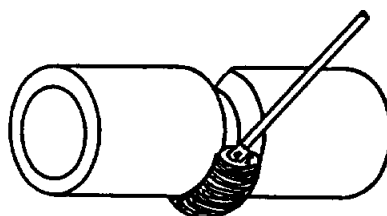
The ASNT scheme differs from the Welding Institute's because the qualification certificates are issued by the company that employs the technician. The qualifications are specific to the type of work carried out by the Company and are not transferable to other companies.

**SNT T 1A** - ASNT certificate categorised in to three levels of qualifications.

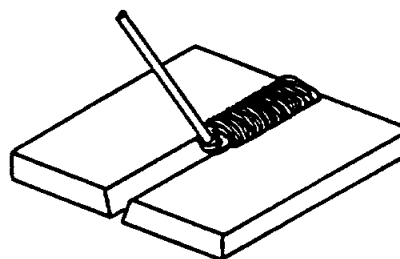
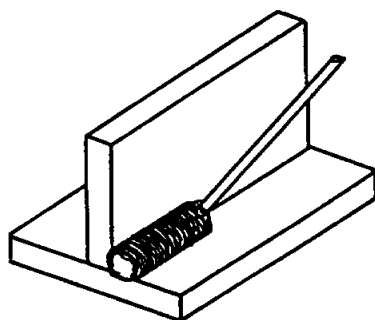
For those who wish to expand on their knowledge of welding "The Procedure Book of Arc Welding" should be obtained. This moderately priced publication is produced by the Lincoln Electric Company, Cleveland, Ohio, U.S.A. and is readily available in Europe. Over the years it has become a standard work of reference for welding both on and offshore and will be found sharing shelf space with the more formal specifications wherever welding is carried out.

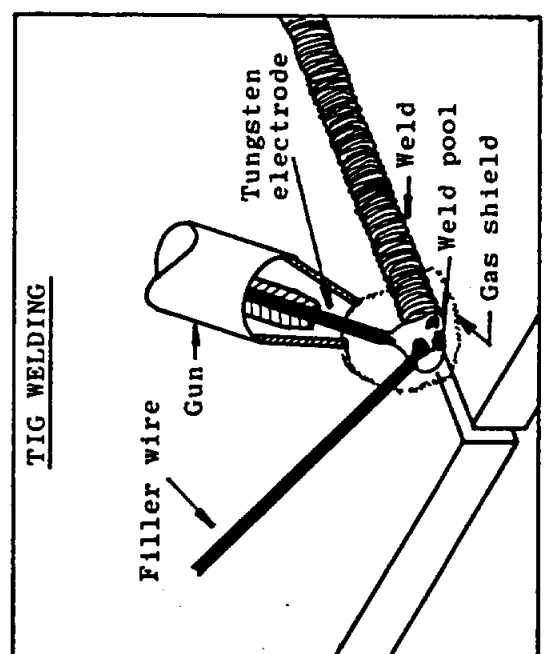
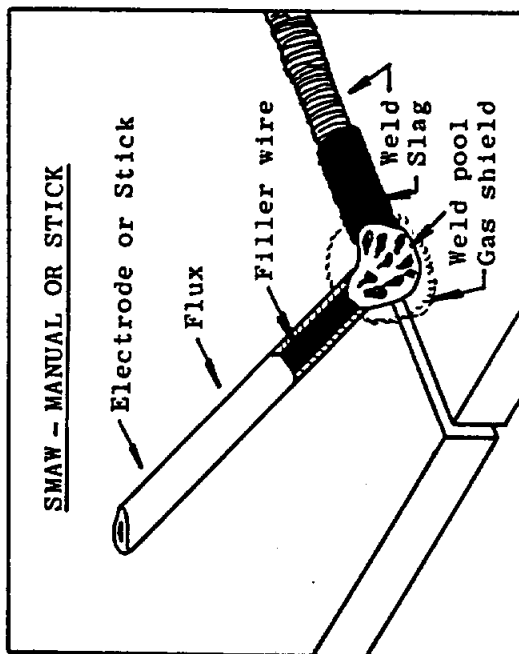
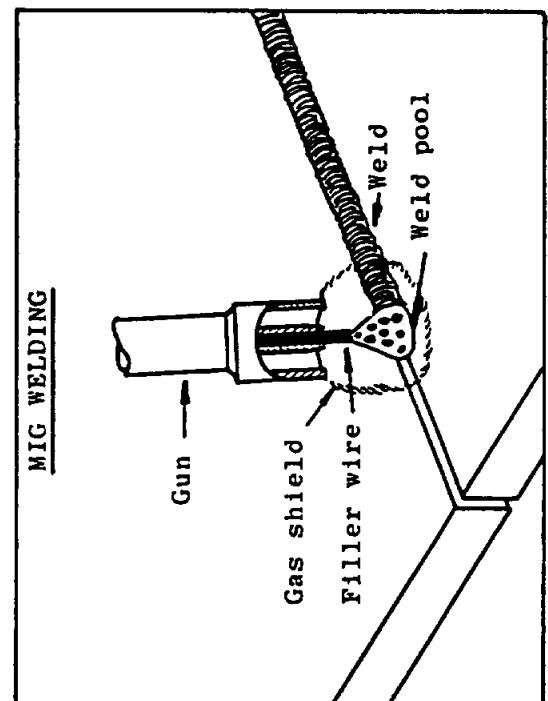
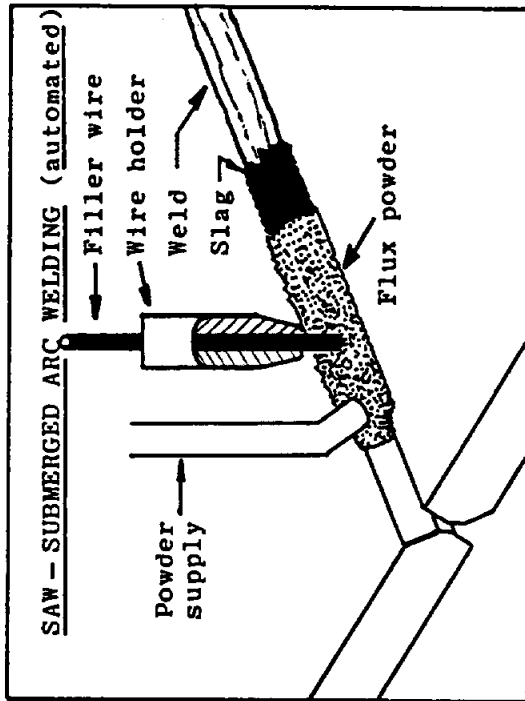


**FILLET WELDS**



**BUTT WELDS**





## WELDING PROCESSES



## APPENDIX III - NON-DESTRUCTIVE EXAMINATION

Non-destructive examination, (NDE) or Non-destructive testing (NDT) provides the means by which components may be examined for defects during the construction of an offshore installation. The type and extent of NDE will be determined by the fabrication specification and EEMUA 158 provides particularly informative reference tables on the subject for structural components whilst the ASME boiler and pressure vessel code is used extensively for piping systems. It should be noted that all NDE should be performed by suitably qualified operators working in accordance with written procedures. The procedures must be based on specifications prepared by National Standards Organisations (NSO) such as The British Standards Institute, ASME, AWS and EEMUA.

There are a number of NDE processes, the more important of which are outlined below. They can be divided into two categories, the first being used for the detection of defects on the surface of the component and the second for detecting defects internally.

### 1. SURFACE INSPECTION TECHNIQUES

#### i) CLOSE VISUAL INSPECTION - CVI

The most basic and still the most important of non-destructive examinations and one which should never be overlooked.

#### ii) MAGNETIC PARTICLE INSPECTIONS - MPI

MPI is the most sensitive and reliable of techniques for the detection of surface and near surface defects in ferro-magnetic materials (iron and steel). To enhance defect definition the object under examination is sprayed with white background paint prior to magnetisation with either a permanent magnet, or an electromagnet. The component is then liberally coated with particles of iron oxide in either liquid or dry powder form. The particles align themselves with any discontinuities in the magnetic field and the defects appear as a clear black line which is emphasized by the white background paint.

NOTE: Permanent magnets should be restricted to the examination of materials of thickness less than 6mm ( $\frac{1}{4}$  inch). An A.C. electromagnet is preferred for thicker sections due to the more intense nature of the field it produces.

#### iii) EDDY CURRENT INSPECTION

Like MPI, eddy current test equipment relies on the disturbing effect that defects have on a magnetic field. A test probe containing an electromagnetic coil is traversed over the article under inspection and the response signal is displayed on an oscilloscope. One of the main advantages of eddy current testing is that it can be used on painted components, although some of the particularly thick offshore paint systems may require removal prior to testing.

#### iv) DYE PENETRANT EXAMINATION

Whilst not as effective as MPI or eddy current inspections "dye pen" is used extensively on both ferrous and non-ferrous components. It involves the application of a red dye which is absorbed by capillary action into surface breaking defects. Surplus dye is removed prior to the application of a developer which highlights the dye retained within the defect.

## **2. VOLUMETRIC INSPECTION TECHNIQUES**

### **i) ULTRASONIC EXAMINATION - U/T**

An ultrasonic examination can be carried out on most homogeneous materials and when performed by a skilled operator it represents the most sensitive of volumetric NDT techniques. It employs an ultrasound signal to search for defects, the results generating a signal which can be interpreted on an oscilloscope. U/T is particularly well suited to the location of cracks and laminations in fusion welded components.

### **ii) RADIOGRAPHY - R/T**

Industrial radiography involves the passing of ionising radiation through an object in order to record the results on radiographic film. It is most frequently used for the examination of circumferential welds and often referred to as bombing. The radiation may be generated by an X-ray machine or by a radioactive isotope such as Iridium or Cobalt. Whilst X-ray equipment generally produces superior results particularly on thin components, isotopes are preferred for site work because they are more compact and do not require an external power source or coolant supply.

## **3. NON-DESTRUCTIVE EXAMINATION SPECIFICATIONS**

### **i) BRITISH STANDARDS**

<b>BS 2910</b>	Radiographic examination of fusion welded circumferential butt joints in steel pipes.
<b>BS 2600</b>	Radiographic examination of fusion welded butt joints in steel.
<b>BS 3923</b>	Ultrasonic examination of welds.
<b>BS 5289</b>	Code of Practice. Visual inspection of fusion welded joints.
<b>BS 6443</b>	Penetrant flaw detection.
<b>BS 6072</b>	Methods for magnetic particle flaw detection.

### **ii) AMERICAN STANDARDS**

**ASME V - Boiler and Pressure Vessel Code**

Article 2 - Radiography  
Article 4 - Ultrasonic inspection  
Article 6 - Liquid penetrant flaw detection  
Article 7 - Magnetic particle inspection  
Article 8 - Eddy current testing  
Article 9 - Visual inspection

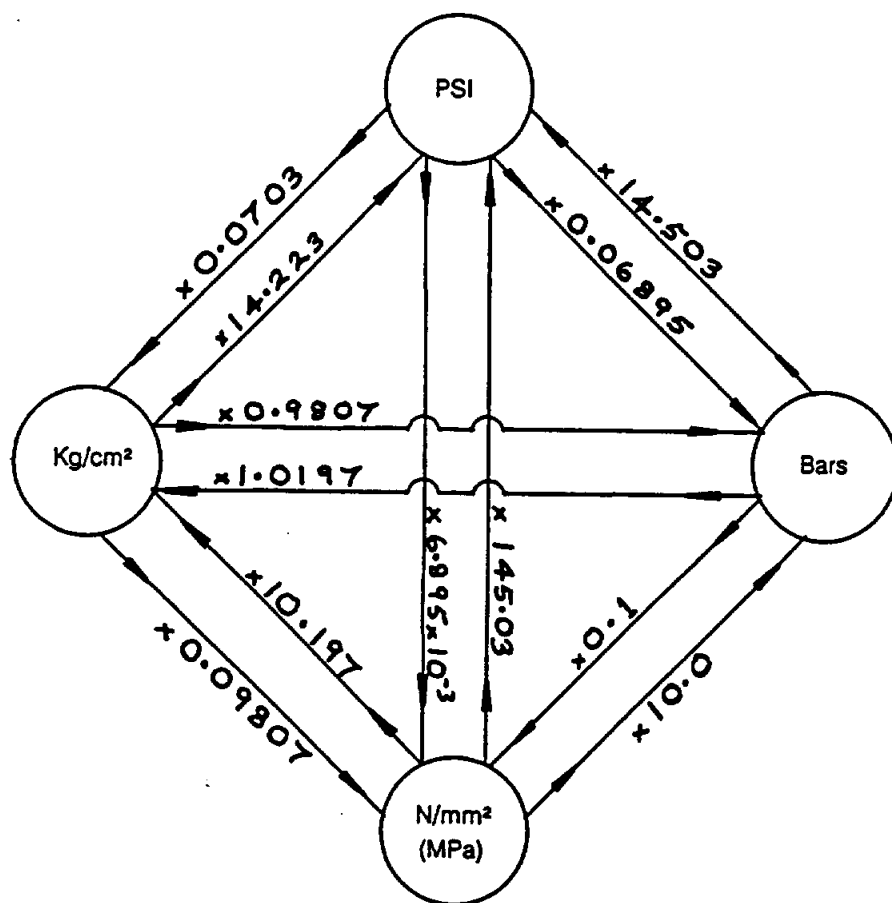
**AWS D1.1 - Structural Welding Code**

(See Chapter 6 - Radiography/Ultrasonic.)

## APPENDIX IV - UNITS OF MEASUREMENT

1 tonne	=	7.5 barrels (crude oil)
1 long tonne	=	1.0165 tonnes
1 barrel	=	42 US gallons (35 imperial gallons)
	=	0.1589 cubic metres
1 cubic metre	=	35.31 cubic feet.
1 billion cubic metres	=	0.83 million tonnes of oil equivalent.
1 cubic metre of gas	=	0.36 Therms
1 tonne of fuel oil	=	406 Therms
1 therm	=	100 cubic feet gas = 100,000 British Thermal units.

## METRIC CONVERSIONS



## APPENDIX V - TABLE OF LINEPIPE DIMESIONS

PLATFORM PIPING

## DIMENSIONS AND MAXIMUM WORKING PRESSURES

## ASTM A106 GRADE B PIPE

[Design temp. -29/204°C (-20/400°F)]

Nominal Size Inches	Outside Diameter Ins/mm	Nominal Wall Thickness Inches	mm	Weight Class	Schedule No.	Working Pressure psig
2	2.375	0.218	5.34	XS	80	2489
	60.3	0.344	8.74	--	160	4618
		0.436	11.70	XXS	-	6285
2.5	2.875	0.276	7.01	XS	80	2814
	73.0	0.375	9.52	--	160	4194
		0.552	14.02	XXS	-	6850
3	3.50	0.300	7.62	XS	80	2552
	88.9	0.438	11.13	--	160	4123
		0.600	15.24	XXS	-	6090
4	4.500	0.237	6.72	STD	40	1140
	114.3	0.337	8.56	XS	80	2276
		0.438	11.13	--	120	3149
		0.531	13.49	--	160	3979
		0.674	17.12	XXS	-	5307
6	6.625	0.280	7.11	STD	40	1206
	168.3	0.432	10.97	XS	80	2062
		0.562	14.28	--	120	2817
		0.719	18.26	--	160	3760
		0.864	21.95	XXS	-	4660
8	8.625	0.322	8.18	STD	-	1098
	219.1	0.406	10.21	--	60	1457
		0.500	12.70	XS	80	1864
		0.594	15.08	--	100	2278
		0.719	18.26	--	120	2838
		0.812	20.63	--	140	3263
		0.875	22.22	XXS	-	3555
		0.906	23.00	--	160	3700
10	10.750	0.365	9.27	STD	40	1023
	273.0	0.500	12.70	XS	60	1485
		0.594	15.08	--	80	1811
		0.719	18.20	--	100	2252
		0.844	21.43	--	120	2700
		1.000	25.41	XXS	140	3271
		1.125	28.58	--	160	3737
12	12.750	0.375	9.52	STD	-	888
	323.9	0.406	10.31	--	40	976
		0.500	12.70	XS	-	1246
		0.562	14.28	--	60	1425
		0.688	17.48	--	80	1794
		0.844	21.43	--	100	2258
		1.000	25.40	XXS	120	2730
		1.125	28.58	--	140	3114
		1.312	32.00	--	160	3700

## APPENDICES

Nominal Size Inches	Outside Diameter Ins/mm	Nominal Wall Thickness Inches	mm	Weight Class	Schedule No.	Working Pressure psig
14	14.000 355.6	0.375	9.52	STD	30	807
		0.438	11.07	--	40	971
		0.500	12.70	XS	-	1132
		0.594	15.08	--	60	1379
		0.750	19.10	--	80	1794
		0.938	23.80	--	100	2304
		1.094	27.00	--	120	2734
		1.250	31.75	--	140	3171
		1.406	35.71	--	160	3616
16	16.00 406.4	0.500	12.70	XS	40	988
		0.656	16.66	--	60	1345
		0.843	21.41	--	60	1780
		1.031	26.19	--	100	2225
		1.218	30.95	--	120	2675
		1.437	36.51	--	140	3212
18	18.000 457.2	0.500	12.70	XS	-	876
		0.562	14.25	--	40	1001
		0.718	19.10	--	60	1319
		0.937	23.80	--	80	1771
		1.156	29.30	--	100	2232
		1.343	34.92	--	120	2632
20	20.000 508.0	0.325	9.52	STD	-	499
		0.500	12.27	XS	-	669
		0.812	20.62	--	60	1098
		1.031	26.19	--	80	1404
		1.280	32.51	--	100	1760
		1.500	38.10	--	120	2079
		1.750	44.50	--	140	2446
		1.968	50.00	--	160	2776
24	24.000 609.6	0.375	9.52	STD	-	415
		0.500	12.70	XS	-	556
		0.562	14.25	--	30	625
		0.687	17.48	--	40	768
		0.968	24.60	--	60	1091
		1.218	30.95	--	80	1383
		1.531	38.89	--	100	1753
		1.812	46.03	--	120	2093
		2.062	52.38	--	140	2399
		2.343	59.38	--	160	2752
30	30.000 762.0	0.375	9.52	STD	-	
		0.500	12.70	XS	-	
36	36.000 914.4	0.375	9.52	STD	-	
		0.500	12.70	XS	-	



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