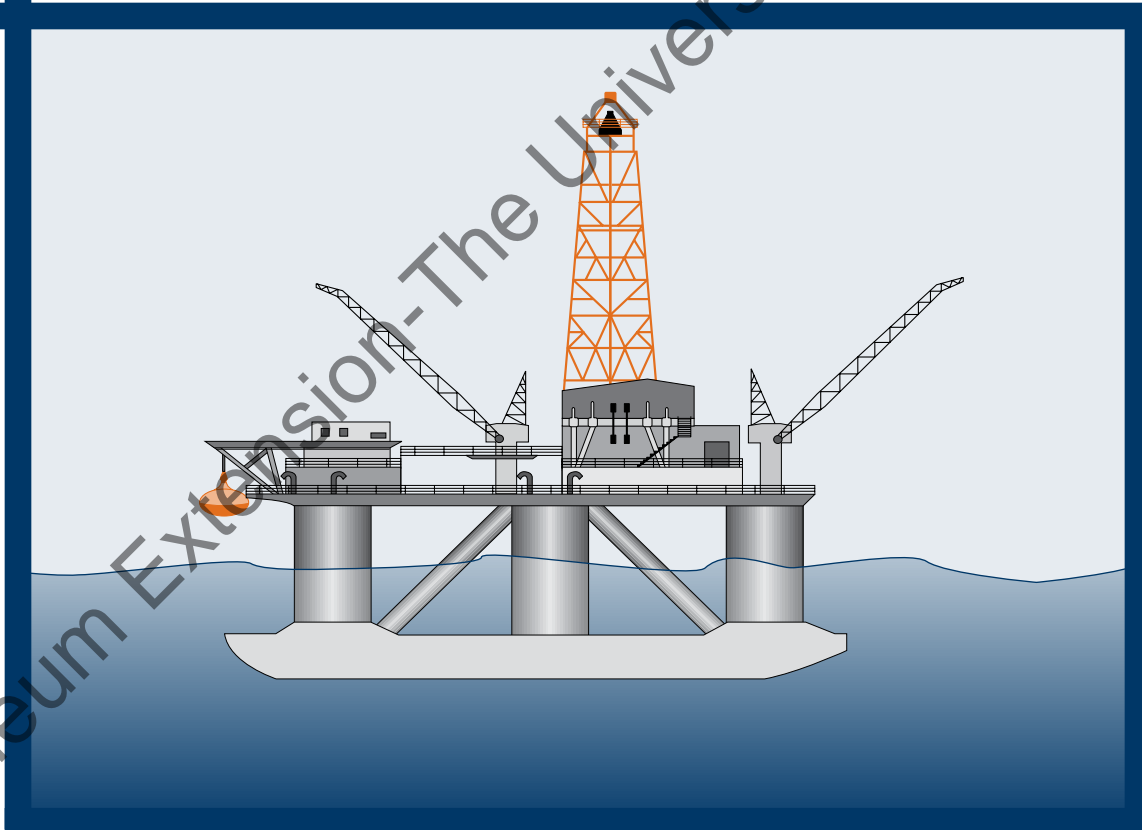




Offshore Well Construction

First Edition



THE UNIVERSITY OF TEXAS
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CHAPTER 1

The Role of Well Construction in the Evaluation and Development of Oil and Gas Reserves

INTRODUCTION

The evaluation and development of oil and gas reserves is a complex process requiring the interaction of numerous different disciplines. Well construction forms a pivotal role in this process as it is responsible for constructing the conduit from the reservoir to the surface.

The process of exploring for oil and gas can be broken down into a number of successive operations, each more expensive and complex than the previous and each generating higher quality data. In addition, at the end of each operation, the data is reviewed and the process amended or terminated as required.

The main components are:

- Geological appraisal
- Geophysical prospecting
- Exploration drilling
- Appraisal drilling
- Development drilling

Geological Appraisal

The known geological data of a region is reviewed. Government bodies have an interest in the economic geology of its sovereign territory and usually enforce laws, which maintain a database of all geological activity within the territory. This means that data which may have been determined during exploration for a particular mineral resource is available to other explorationists. It is obvious that regions of the earth with easy access have been explored in greater detail.

The objective is to identify the types of rocks in which oil and gas may have accumulated. These are sedimentary rocks and the sequence of occurrence of the rocks can be related to other sequences in which oil and gas have already been found. Unfortunately, the patterns in deposition are unreliable and, although patterns in one area may be similar to those where oil and gas have been found, little confidence can be placed on them containing the correct structures to trap oil and gas and also actually containing oil or gas.

Onshore, a geological survey of surface features may be conducted to confirm the geological prognosis, or to fill in details which may be missing from existing surveys.

Offshore, this can be done with shallow drilling.

Geophysical Prospecting

Geophysical prospecting is the application of the principle of physics to the study of subsurface geology.

Geophysical prospecting enhances the geological information already known about a formation. The objective is to separate the basement rocks (those which were formed first and on which sedimentary basins may have subsequently formed) from the sedimentary rocks since oil and gas form in sedimentary rocks. Geophysical methods can be used to measure the thickness of sediments and to measure the shape of structures within the sediments.

Geophysical surveys can be divided into two broad categories:

1. Reconnaissance surveys to outline possible areas of interest where there are thick sediments and the possibility of structural traps
2. Detailed surveys to define well locations to test specific structures

CHAPTER 2

Well Design Process

OVERVIEW

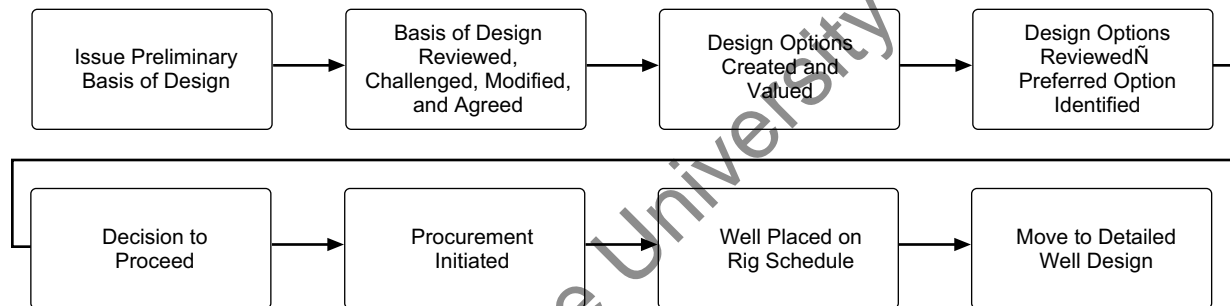
The well construction process can be broken down into five sequential phases of work, as follows:

1. Preliminary well design
2. Detailed well design
3. Prepare drilling program
4. Execute well program
5. Analyze and improve performance

Well design focuses primarily on the preliminary and detailed well design and the preparation of the drilling program.

PRELIMINARY WELL DESIGN

Preliminary well design is essentially a screening stage of the well design process. The major steps are shown below.



Issue Preliminary Basis of Design

Once the geological and geophysical studies have identified a potential well location, the subsurface team will work up a basis of design. This is the information that gets handed over to the well construction team and forms the basis of the well design. The basis of design will generally provide information on the following:

- Well name and number
- Well objectives
- Total depth
- Surface location
- Water depth
- Target location
- Target size and tolerance
- Target constraints
- Geological prognosis
- Seismic section
- Expected hydrocarbons
- Anticipated pore pressures
- Anticipated temperature profile
- Offset wells
- Geological hazards (shallow gas, faulting, H₂S, CO₂, lease line restrictions, flow lines, etc.)
- Additional constraints (drilled before a certain date, etc.)
- Evaluation program (details and justification of required wireline logs, coring, and testing)

CHAPTER 3

Casing Design

INTRODUCTION

Casing design is about achieving the total depth of the well safely, with the most cost effective number of casing or liner strings.

Purpose of Installing Casing

In order to allow the drilling and completing of a well, it is necessary to line the drilled open hole with steel pipe or casing. Once in place, this pipe is cemented, supporting the casing and sealing the annulus in order to

- strengthen the hole.
- isolate unstable, flowing, underbalanced, and overbalanced formations.
- prevent the contamination of freshwater reservoirs.
- provide a pressure-control system.
- confine and contain drilling, completion, produced fluids, and solids.
- act as a conduit for associated operations (drilling, wireline, completion, and further casing or tubing strings) with known dimensions (IDs, etc.).
- support wellhead and additional casing strings.
- support the BOP and Christmas tree.

There are primarily six types of casing installed in an onshore or offshore well:

- Stove pipe, marine conductor, foundation pile
- Conductor string
- Surface casing
- Intermediate casing
- Production casing
- Liners

Stove Pipe, Marine Conductor, Foundation Pile

Stove pipe is used for onshore locations and is either driven or cemented into a predrilled hole. The pipe protects the immediate soil at the base of the rig from erosion caused by the drilling fluid.

Marine conductor is a feature of offshore drilling operations where the BOP stack is above the water. It provides structural strength and guides drilling and casing strings into the hole. It is usually driven or cemented in a predrilled hole. The string helps isolate shallow unconsolidated formations and protects the base of the structure from erosion by the drilling fluid.

Foundation pile is usually jettied in or cemented into a predrilled hole from a floating drilling unit—where the BOP stack is on the seafloor. Again, the string isolates unconsolidated formations and supports the guide base for the BOP stack, Christmas tree, or flowbase, and guides drilling and casing strings into the hole.

Conductor String

This string is used to support unconsolidated formations, protect freshwater sands from contamination, and case off any shallow gas deposits. The string is usually cemented to the surface onshore and to the seabed offshore. This is the first string onto which the BOP is installed. If surface BOPs are used (i.e., jackups) the conductor string also supports the wellhead, the Christmas tree, and subsequent casing strings.

CHAPTER 4

Drilling and Completion Fluids

FUNCTIONS OF A DRILLING FLUID

The primary functions of a drilling fluid are:

- Well control
- Maintain hole stability
- Hole cleaning
- Transmit hydraulic horsepower to the bit
- Formation evaluation

These functions are achieved by careful selection of the drilling fluid and maintenance of its properties.

Additional functions of a drilling fluid are:

- Suspend cuttings and weighting agent while the fluid is static; e.g., connections
- Release entrained cuttings at surface
- Cool and lubricate the bit and drill string
- Create a thin, impermeable filter cake to reduce fluid invasion
- Support tubulars through buoyancy effect
- Prevent and control corrosion of drill string, etc.

TYPES OF DRILLING FLUID

There are three main types of drilling fluid, distinguished by their base fluid formulation.

Air/Gas

Used for drilling hard, dry formations or to combat lost circulation. Rarely used offshore, except for underbalanced or coiled-tubing drilling.

Water-Based Mud

The main types of water-based mud are

- Nondispersed
- Dispersed
- Calcium treated
- Polymer
- Low solids
- Salt water

Nondispersed Muds

Generally includes lightly treated, low-weight muds, and spud muds. No thinners added. Usually top hole and shallow well applications.

Dispersed Muds

With increasing depths and mud weights, mud formulations require dispersant additives (lignosulphonates, lignites, tannins) to cancel the interparticle attractive forces that create viscosity in water-based mud. This effectively extends the use of the mud system until it has to be replaced.

CHAPTER 5

Cementing

OBJECTIVES

Primary Cementing

- Isolation of casing shoe
- Isolation of production zones—prevent cross-flow between intervals at different pressures
- Protection of water zones—prevent drilling fluid contamination of aquifers
- Isolation of problem interval—extreme losses, well control, side tracking
- Protection of casing—from corrosive formation fluids; e.g., H₂S, CO₂
- Casing support—e.g., support for conductor (load bearing—bending moments derived from supporting BOP/tree/riser and potential snag loads from fishing activities), prevent thermal buckling

Secondary or Remedial Cementing

Additional cementing done at a later stage; e.g., sealing off perforations, top up job on conductor, repair casing leaks, squeeze casing shoe, setting plugs, etc.

PLANNING

Planning for a cement job consists of evaluating a number of features, including:

- Assessment of hole conditions (hole cleaning, size, washouts, temperature)
- Mud properties
- Slurry design
- Slurry placement
- Additional equipment (float equipment, centralizers, ECPs)

COMMON CEMENTING PROBLEMS

Common problems that affect all cement jobs include:

- Poor hole condition (doglegs, borehole stability, washouts, hole fill, cuttings beds, etc.)
- Poor mud condition (high gel strengths and yield point, high fluid loss, thick filter cake, high solids content, lost circulation material, mud/cement incompatibility)
- Poor centralization (cement not placed uniformly around the casing, leaving mud in place)
- Lost circulation
- Abnormal pressure
- Subnormal pressure
- High temperature

CEMENT TYPES

API defines 9 different classes of cement (A to H) depending on the ratio of the four fundamental chemical components (C₃S, C₂S, C₃A, C₄AF where C = calcium, S = silicate, A = aluminate, and F = fluoride).

CHAPTER 6

Drill Bits

BIT SELECTION

Bit performance is measured by the total length and time drilled before the bit has to be pulled and replaced. Minimum cost per metre (or foot) is the primary objective. Careful review of offset well data must be undertaken when selecting a bit for any particular hole section.

Primary considerations when selecting a bit type are:

- Geology
 - Formation properties
 - Compressive strength
Refers to the intrinsic strength of the rock which is based upon its composition, method of deposition, and compaction. It is important to consider the 'confined' or 'in situ' compressive strength of a given formation. Many bit manufacturers now provide a supplementary rock strength analysis service as an aid to bit selection.
 - Elasticity
Affects the way in which a rock fails. A rock that fails in a plastic mode will deform rather than fracture.
 - Abrasiveness
 - Overburden pressure
Affects the amount of compaction of sediments and therefore the rock hardness.
 - Stickiness
 - Pore pressure
Affects mud weight requirements which, in turn, can affect penetration rates.
 - Porosity and permeability
 - Formation changes within a given hole section
Changes in formation during one bit run can have a significant effect on bit performance. The formations to be drilled and the predicted depths of formation changes will be given in the drilling program and will form the basis of bit selection. It is important to remember the difference between exploration and appraisal/development drilling in that:
 - For appraisal/development drilling, much will be known about the properties of the predicted formations and bit selection will be based upon offset bit performance along with electric log data (sonic, gamma ray, mud log data, core samples, etc.).
 - For exploration drilling, little may be known of the drillability of the formations that are likely to be encountered and so a more conservative bit program will be developed. In such situations, it is prudent to load out a wider variety of bit designs to cover all eventualities.
- Hole size and casing program
- Directional profile of well path and steerability of bit design
- Drive type (rotary/rotary steerable/mud motor/turbine)
- Drilling fluid properties
- Hydraulics
- Rig capabilities

CHAPTER 7

Hydraulics and Hole Cleaning

INTRODUCTION

Hydraulics planning is part of the overall drilling optimization process.

It involves a calculated balance of the various components of the circulating system to maximize ROP and keep the bit and hole clean while remaining within any constraints of the wellbore, surface, and downhole equipment.

CONSIDERATIONS FOR HYDRAULICS PLANNING

Maximizing ROP

Cuttings removal from the bottom of the hole is related to the fluid energy dissipated at the bit (bit hydraulic power). It has been shown that bit hydraulic horsepower is optimized when the pressure differential (pressure drop) across the bit is equal to two-thirds of the total system pressure (pump pressure). Maximizing hydraulic horsepower can be used to increase penetration rate in medium-to-hard formations.

Hole Cleaning

In soft formations or deviated holes, hole cleaning is often the dominant factor. There is little point in maximizing the ROP by selecting nozzles that optimize bit hydraulic horsepower or impact force, if the resulting flow rate is insufficient to lift the cuttings out of the hole. In these instances, it is preferable to determine a suitable flow rate first and then optimize the hydraulics.

Annulus Friction Pressure

In slim-hole or deep wells, the annulus friction pressure needs to be considered. Too high an annulus friction pressure increases the *equivalent circulating density (ECD)* and can lead to lost circulation, differential sticking, or hole instability.

Erosion

Soft, unconsolidated formations are prone to erosion if the annulus velocity and, therefore, flow rate are too high or the annulus clearance is small leading to the possibility of turbulent flow. In these instances, a reduction in flow rate will be required to minimize erosion.

Lost Circulation

If heavy lost circulation is anticipated and large quantities of LCM could be pumped, it may be necessary to install larger bit nozzles to minimize the risk of bit plugging.

FACTORS THAT AFFECT HYDRAULICS

The rig equipment, drill string and downhole tools, wellbore geometry, mud type, and properties are all factors that can affect hydraulics.

Rig Equipment

The single biggest factor of the rig equipment is the pump pressure limitation and volume output of the mud pumps in use. Increasing pump liner sizes increases the volume output but decreases the maximum allowable pump pressure. Most high-pressure pipe work from the mud pumps to the kelly or top drive is rated at a pressure higher than the pump rating.

CHAPTER 8

Drill String Design

DRILL STRING COMPONENTS

The principal components of the drill string are as follows.

Kelly or Top Drive System (TDS)

It is not exactly part of the drill string but transmits and absorbs torque to or from the drill string while carrying all the tensile load of the drill string.

Drill Pipe (DP)

Transmits power by rotating motion from the rig floor to the bit and allows mud circulation.

Drill pipe is subjected to complex stresses and loads as is the rest of the drill string. Drill pipe should never be run in compression or used for bit weight except in high angle and horizontal holes where stability of the string and absence of buckling must be confirmed by using modelling software.

Heavy Weight Drill Pipe (HWDP)

HWDP makes the transition between drill pipe and drill collars, thus avoiding an abrupt change in cross-sectional area. It is also used with drill collars to provide weight on the bit, especially in 6" or 8H" holes where the buckling effect of the HWDP due to compression is minimal.

HWDP reduces the stiffness of the BHA. HWDP is also easier or faster to handle than DC and, more important, reduces the possibility of differential sticking.

Drill Collars (DC)

Provide weight on the bit, keeping the drill pipe section in tension during drilling. The neutral point should be located at the top of the drill collars section: 75 to 85% (maximum) of the drill collars section should be available to be put under compression (available weight on bit).

Other Downhole Tools

Include: stabilizers, crossover, jars, MWD, underreamer, etc.

They all have different functions, but have two major common points: their placement is crucial when designing the drill string and they introduce 'irregularity' in the drill string; i.e., different ID/OD and different mechanical characteristics (torsion/flexion, etc.), which must be taken into account when designing the drill string.

Drill Bit

See Chapter 6, Drill Bits.

DRILL STRING CONSIDERATIONS

Drill Pipe

The main factors involved in the design of a drill pipe string are

- collapse and burst resistance.
- tensile strength (tension).

CHAPTER 9

Surveying and Directional Drilling

SURVEYING

Why Survey?

Accurate data about the position of a borehole is required in order to monitor and control where a borehole is and where it is going for the following reasons:

- To hit geological targets
- To provide a better definition of geological and reservoir data to allow for production optimization
- To avoid collision with other wells
- To define the target of a relief well for blowout contingency planning
- To provide accurate vertical depths for the purpose of well control
- To provide data for operational activities such as running and cementing casing
- To fulfill the requirements of local legislation

Models of the Earth

The earth is commonly described as a spherical object but it has a very irregular surface and carries mountain chains and deep-sea canyons in excess of 5 miles above and below mean sea level. The problem confronting surveyors is how to represent any point on the earth's surface on a flat sheet. Small areas of the earth may appear to have a flat surface but, by and large, this is not the case. This has rendered it necessary to look more closely at the shape of the earth so that a method of representing this shape on a flat surface can be used (fig. 9.1).

The Geoid

A smooth surface representing the earth's surface and referred to as the geoid can be produced, but it is impossible to describe any point on this surface mathematically. The

geoid effectively smoothes out the irregularities of the earth's surface, but in so doing, creates an irregular shaped object itself. If mean sea level could be established everywhere, then this would be the surface of the geoid. All astronomical observations are made relative to the geoid and astronomical latitudes and longitudes are positions on the geoid.

The Spheroid

The earth can be more accurately represented in shape by that of an oblate spheroid flattened at the poles by approximately one part in three hundred due to rotation. This can be described mathematically by an algebraic equation, which can then be used as the basis for calculations. Over a dozen different ellipsoid shapes describing the earth mathematically have been generated and are in use today.

In 1924, an official ellipsoid was defined (based on the existing Hayford Ellipsoid of 1909) and called the International Ellipsoid. This had a flattening factor of 1:297, a polar radius of 6,356,911.9 m and an equatorial one of 6,378,388 m.

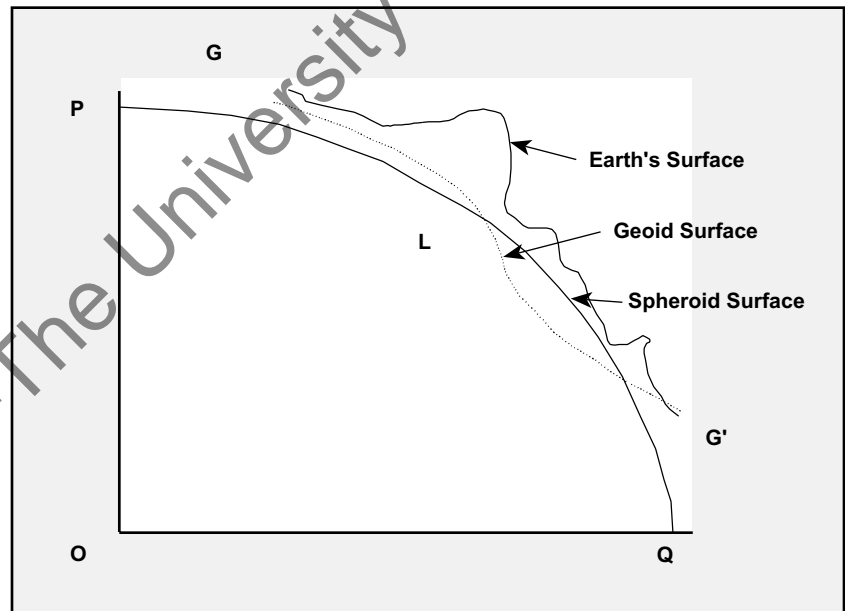


Figure 9.1 Shapes representing the earth

CHAPTER 10

Formation Evaluation

INTRODUCTION

A wide variety of information is available from the well that can be used by the geologist and petrophysicist to refine the geological and petrophysical models and to gain a better understanding of the reservoir, assess how large the reservoir is, and how it will perform if placed on production.

Information can be obtained from the following sources:

- *Data collected while drilling*
 - Penetration rate
 - Cuttings analysis
 - Mud losses/gains
 - Shows of gas/oil/water
- *Core analysis*
 - Lithology
 - Presence of shows
 - Porosity
 - Permeability
 - Special core analysis
- *Log analysis (wireline and MWD/LWD)*
 - Electrical logs
 - Acoustic logs
 - Radioactivity logs
 - Pressure measurements
 - Special logs
- *Productivity tests*
 - Formation tester
 - Drill stem test
 - Production test

Mud Logging

Data collected while drilling is usually incorporated as part of the mud logging service.

The mud log provides a record of the penetration rate, lithology (inferred from cuttings analysis), and cuttings description on a depth basis together with general comments on the drilling parameters, mud type and properties, hydrocarbon shows, logs run, cores cut, etc.

Coring

Cores provide more accurate information than cuttings. However, unless special circumstances dictate, it is usually only cost effective to core the reservoir section of a well.

A core allows a detailed lithological description of the reservoir to be made. Additional tests can be performed in the laboratory to establish the porosity and permeability of the rock, which can then be used to calibrate the response from logging tools.

Log Analysis

Logs can be obtained by running specialist tools on wireline or, as is becoming more common, by including a LWD tool as part of the MWD tool string. Note that not all wireline logs are available as LWD logs.

A log is the recording of the physical properties of the formations drilled on a depth basis.

CHAPTER 11 Rig Equipment and Sizing

GENERATIONS OF OFFSHORE DRILLING UNITS

Generations are used to differentiate semisubmersible hulls. This section describes the term *Generations*.

Year of Construction

Generation is traditionally based on age. Semisubmersibles are built to satisfy demand and construction dates coincide with peaks in oil price and increased demand. Generations are based on the following construction dates.

Generations	Year of Construction
1st	1962 to 1969
2nd	1970 to 1981
3rd	1982 to 1986
4th	1987 to 1998
5th	1999 onwards (?)

Technical Capability

Generation is based on the technology of equipment installed on the rig. When rigs are built, they generally reflect the technology available at the time. As technology develops, more complex work can be carried out and, over the past thirty years, semisubmersibles have moved into deeper water to drill deeper more complex wells.

Generations	Examples of Development of Technology
1st	800 ft water depth, 2 × 1,250 hp mud pumps, kelly, 1,450 ton variable deck load (VDL), manual derrick
2nd	1,500 ft water depth, 2 × 1,600 hp mud pumps, kelly, 3,000 ton VDL, manual derrick
3rd	2,500 ft water depth, 2 × 1,600 hp mud pumps, kelly, 3,800 ton VDL, automatic pipe handling
4th	3,500 ft water depth, 3 × 1,600 hp mud pumps, TDS3 top drive, 4,300 ton VDL, automatic pipe handling
5th	8,000 ft water depth, 5 × 2,200 hp mud pumps, TDS8 top drive, 5,000 ton VDL, dual activity

CHAPTER 12

Drilling Problems

INTRODUCTION

Drilling problems cover nonroutine events such as:

- Well control
- Stuck pipe
- Fishing
- Lost circulation
- Hole stability
- Hydrates
- Mud contamination
- Hole cleaning
- Formation damage

Well control and stuck pipe will not be covered in this manual. Some of the above subjects have been covered in earlier sections of this manual and will not be discussed further.

The key to dealing with drilling problems is to be aware of what is likely to occur and to have contingency plans and equipment in place to effectively deal with them.

FISHING

There is a multitude of fishing tools available to cover a whole range of scenarios.

However, the single most important rule is to always have sufficient fishing equipment available on the rig to make a first attempt at fishing any tool that is run in the hole. To accomplish this, it is important to have a detailed drawing of all tools, including wireline logging tools that show outside and inside dimensions.

Of course, if logistics is an issue then additional equipment can be held on site.

A typical fishing equipment list includes

- Overshots
- Sufficient grapples (spiral and/or basket) to cover all sizes plus over and undersize
- Overshot lip guides and extensions
- Fishing jars and accelerators
- Bumper subs
- Taper taps
- Safety joints
- Reverse circulating junk baskets
- Mills

Always ensure that the dimensions of any fishing tools are recorded prior to being run in the hole. **DO NOT RELY ON GENERIC SCHEMATICS FOR MEASUREMENTS.** This applies also to replacement tools (crossovers, etc.).

Always ensure that all relevant personnel are aware of how particular tools operate.

Always ensure that tools have been redressed correctly prior to being run in the hole. If possible, perform a function check.

Always ensure that fishing tools are included on preventative maintenance routines. All elastomers (e.g., overshot packers) have a finite shelf life. Ensure that they are stored correctly and replaced regularly.

CHAPTER 13

Advances in Technology

HORIZONTAL DRILLING

Horizontal drilling has become commonplace during the last decade and now covers the range of well types noted below. In general, horizontal wells are drilled in development areas where the formations and pressures are known. However, there is an extra time element required to plan and design a horizontal well—it will probably take twice as long to plan, design, and order the equipment items, and take approximately 50% extra time to drill. This is due to the additional cost of specialized equipment, safety constraints, and time taken to achieve the build along the horizontal leg. Also, the longer the horizontal section that needs to be drilled, the lower the build rate. The majority of horizontal wells are drilled using medium radius builds.

Additional factors need to be considered when drilling a horizontal well, especially the need for primary well control where there is a greater requirement to maintain constant bottomhole pressure during a well kill. Hole cleaning is also more difficult due to the presence of 'dune buildup' across the build sections, and can also increase the chances of swabbing. Horizontal drilling has become the norm in many areas where the requirement is to maximize production. The current distance records are hampered only by the equipment limits of the respective drilling rigs, especially the hoisting capacity and maximum flow rates and pump capacity.

Definition

Horizontal drilling is the process of directing a drill bit to follow a horizontal path, approximately 90 degrees from vertical.

Purposes

- Maximize production
- Enhance secondary production
- Enhance ultimate recovery
- Reduce the number of wells required to develop a field

Main Types

- Short radius (1° – 4° /1 ft) shallow wells, can go from vertical—horizontal in 50 ft
- Medium (8° – 20° /100 ft) fractured reservoirs, need 300 ft to achieve build
- Long radius (2° – 8° /100 ft) offshore, inaccessible reservoirs, need 1,500 ft
- Ultra short radius (almost no build)

Applications

- Tight reservoirs (permeability < 1 md)
- Fractured reservoirs
- Economically inaccessible reservoirs
- Heavy oil reservoirs
- Channel sand and reef core reservoirs
- Reservoirs with water/gas coning problems
- Stratified thin reservoirs

CHAPTER 14

Subsea Systems

INTRODUCTION

The exploration for oil and gas offshore began in the late 1800s, and in 1896 an offshore well was drilled off the coast of California. In 1938, the discovery of the Creole field 2 km (1.24 ft) from the coast of Louisiana in the Gulf of Mexico heralded the beginning of the move into open, unprotected waters. In this instance, a 20 m (65 ft) by 90 m (295 ft) drilling platform was secured to a foundation of timber piles set in 4 m (13.12 ft) of water. Typically, these pioneering offshore wells utilized piers to create a platform above the prospect which thus enabled them to drill vertical wells into the target.

As the search for oil and gas reserves has continued to intensify, so exploration has moved into increasingly deeper waters. The first subsea well was completed by Shell in 1960 and came on stream in January 1961. This marked both the successful conclusion of many years of R&D and the beginning of a new era in subsea production. Nowadays, subsea completions are a commonplace option and it is the mode of production that is changing. Originally, such wells would have been tied back directly to a platform but now alternatives exist and can be ranked for any particular field depending on cost and water depth.

CURRENT SUBSEA DEVELOPMENTS

Current subsea development options include:

- Tension leg platforms without storage (TLP)
- Floating production vessels without storage (FPV)
- Floating storage units (FSU)
- Floating production storage and offloading vessel (FPSO)
- SPAR buoys for storage or production and storage
- Deep draft semisubmersibles with storage and offloading (DDSS)

FPSO

The idea of FPSOs has been around for many years and the concept has been utilized since the 70s when conversions from existing tankers was the norm. In the late 80s, the Petrojarl heralded the first of the turret systems and was marketed as a testing and early production system. Since then, various turret designs have appeared and include those on the Gryphon, Uisge Gorm, Captain, Anasuria, and Foinavon.

Definitions

Floating—the body is in equilibrium when floating. This excludes TLPs which use buoyancy to maintain equilibrium. The unit must have a displacement and buoyancy compatible with its payload requirement, a form compatible with its station-keeping requirement, and be able to provide a safe, stable platform as a working environment.

Production—the vessel could contain primary and secondary processing equipment to treat live well fluids; e.g., oil/water separation. These are field specific and can range from a single stage separation to a full blown separation, compression, and injection system with its associated power requirements.

Storage—able to store significant quantities of oil until it can be removed by shuttle tanker. This could be due to the lack of an effective export option in the vicinity other than a shuttle tanker or to the poor quality of the crude which would incur a high pipeline tariff. Note that lack of sufficient storage could be detrimental in the long term if production has to be halted because of a logjam in the export route (planned shutdown excepted).

Offloading—contains a means by which oil can be transferred from storage to either a shuttle tanker or alternative export source. Direct unloading is permissible only if there are no weather implications; i.e., the FPSO can weathervane. If that is the case, then a remote-loading buoy may be required. Such remote buoys would include:

- Surface loading buoys (CALM systems)
- Loading towers

CHAPTER 15

Completion Equipment

INTRODUCTION

Completion design is the process of converting a drilled wellbore into a safe and efficient production or injection system.

Prior to starting any design the following information is required:

- *Reservoir parameters*
 - Porosity, permeability, homogeneity, thickness, angle, water/gas/oil pressure profiles
- *Rock characteristics*
 - Rock strength, formation damage potential
- *Production constraints*
 - Fluids handling, injection pressures
- *Fluid characteristics*
 - Density, composition, gas-oil ratio, toxicity, pour point, scaling tendency, wax, asphaltene, CO₂, contaminants
- *Well appraisal data*
 - Rates, pressure, temperatures, samples
- *Facilities information*
 - Control line pump pressures, flow-line sizes, sampling/testing/monitoring, safety constraints
- *Drilling data*
 - Well profile, casing program (and constraints), safety valve depth constraints
- *Field economics*
 - Time frame and importance of fluids, life of field, trade off between capital expense and operating expense, tax implications

Some of the above information might not be readily available or can be reached by discussion with other members of the project team. If a specific tubing size is required to meet a flow rate, then it needs to fit inside the production casing, so discussion is needed with the drilling engineer.

The information is used to determine what type of completion is run, the tubing size, material specification, and the additional completion equipment used.

Tubing design (similar to casing design) is undertaken. The design needs to accommodate collapse, burst, and tensile load cases for the complete life of the well.

Generally speaking, the simpler the completion the greater its reliability.

COMPLETION TYPES/CLASSIFICATION

There are a number of ways of classifying completions. However, the main types are as shown below.

- | | |
|---|---------------------------|
| <i>Interface between wellbore and reservoir</i> | – Open hole |
| | – Cased and uncemented |
| | – Cased and cemented |
| <i>Production method</i> | – Flow naturally |
| | – Require artificial lift |
| <i>Stage of completion</i> | – Initial |
| | – Recompletion |
| | – Workover |

CHAPTER 16

Technical Limit Drilling

INTRODUCTION

Technical limit drilling is a performance improvement process that advocates the pursuit of sound engineering and proper planning to both the onshore planning and offshore execution phases of well construction.

It is nothing new and is certainly not rocket science. It was first called technical limit by Woodside, operating on the northwest shelf of Australia in the early 1990s. This was based on the improvements that Unocal, Thailand achieved in the late 1980s and early 1990s. Since then Shell has adopted a similar principle and called it drilling the limit (DTL) and Amerada Hess called it to the limit (T²L).

The technical limit philosophy is based around two questions relating to performance.

- Where are we now?
- What is possible?

Where Are We Now?

This question can be answered by reviewing past performance or historical data.

Essentially it involves breaking the well down into discrete phases and identifying the conventional lost time or downtime that has occurred. This data can then be reviewed and steps taken to prevent this downtime from occurring again.

Examples of this include:

- Determining the root cause of hole instability on directional wells.
- Running vibration subs to eliminate downhole vibration that was responsible for multiple twistoffs.
- Utilizing a hydraulic swivel packing instead of a conventional swivel packing to eliminate rig downtime.

What Is Possible?

Once the current level of performance has been established, the question then becomes one of where could our level of performance go or what is possible?

This is a two-stage process that first challenges existing practices (that's the way we've always done it, is no longer an acceptable answer) and secondly starts asking, what if?

Challenging existing practice focuses on what is known as invisible lost time (ILT). ILT is time that is not classed as downtime, but is time that is nevertheless not productive or is inefficient.

Examples of this include:

- Slow ROP
- Excessive connection time caused by outdated practices

Asking what if focuses on enhancements to equipment or identifies new technology that will improve the overall time taken to perform a specific operation.

Examples of this include:

- Rotary steerable tools
- Multilaterals
- Dual activity derricks

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