WELL INTERVENTION
WITH IWCF-CERTIFICATION
PRINCIPLES & PROCEDURES
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1. BARRIER

1.1. Definition

The term “Barrier” refers to mechanical or fluid means of limiting fluid flow. Barrier(s) may be located downhole (mechanical plugs, columns of fluid), or topside (valves, plugs).

During well operations there must always be at least two independent, tested barriers in the well, in order to prevent an undesired flow of hydrocarbons from the well to the surface. If one of these barriers should fail, the other will maintain the barrier function and prevent a blowout.

During operations, barriers must be defined and fault criteria established. The availability of the barriers must be evaluated against the risk involved in the operation. Pressure testing methods and intervals must be established. As far as possible the barriers should be tested in the direction of flow of the well. The location of valves and the status of the barriers must be known at all times.

The barriers must be capable of being operated independently of each other. No failure may be capable of destroying the functional capacity of both barriers simultaneously.

The barriers must be physically independent of each other and may not share a barrier element (in order to prevent a failure in the common barrier element from leading to the loss of both barriers).

If one barrier fails it must be possible to put compensatory measures into effect immediately. During this phase, efforts to re-establish the barrier are the only type of work permitted.

If it is not possible to set up two tested barriers, we must ensure that the total risk does not increase.

Barriers are divided into primary, secondary and tertiary barriers (if installed). Primary barriers are those that “control” the connection to the reservoir (by opening or closing it for production or injection). Secondary barriers are brought into action if the primary barrier should fail, and if the secondary barrier fails, the tertiary barrier is utilised, etc.

NB: In most operations, the primary and secondary barriers will vary according to the phase of the operation.
“Envelope” is a concept that is utilised in considering a barrier as part of a total system that involves pressure or fluids. The barrier itself (e.g. a wireline BOP) will not be of much help if the complete system is not intact (Xmas tree, completion string, extension tubing).

1.2. Mechanical barriers

Barriers fall into two classes: mechanical and fluid.

If we study a well, starting at the reservoir and working towards the surface, we encounter the following mechanical systems:

a) **Cemented liner:**

The liner is located 50 to 100 m down the casing. At the junction of the casing and the liner (liner lap) we find either cement alone, a packer or a combination of the two.

The liner will always form part of the envelope that comprises the primary barrier.

b) **Cemented casing:**

200 m above the casing shoe is the minimum cementing length. Cementing normally continues to above the depth at which the well’s production packer will be installed. The production packer will be installed at a depth sufficient to ensure that if the casing should leak (below the production packer), this will not result in fracturing of the formation outside the casing (underwater blowout).

In monobore wells, in which the completion string meets the liner (PBR) with a sealstem, the casing will form part of the well’s secondary casing.

If the completion string does NOT include a seal stem, that part of the casing that rises to the completion string’s production packer will be the envelope that makes up the primary barrier. The casing above the production packer will form part of the well’s secondary barrier.

c) **Completion string:**

The completion string will form part of the primary barrier in the vast majority of operational situations. In the Norwegian sector, the BOP is used as a barrier - in other national sectors this is not normally the case (by definition a barrier must be tight).
d) Tubing hanger:

The tubing hanger is part of the primary barrier. The tubing hanger is the component that transfers the weight of the completion string to the wellhead. On the outside of the tubing hanger we find the hanging point, which makes a metal-to-metal connection with the well-head. This ensures the integrity of the secondary barrier (the annulus) as long as the tubing hanger is locked to the wellhead (via the lock/locking ring/Xmas tree).

e) Xmas tree:

This counts as a barrier in most operations (production, pumping, wireline). In normal operation the Xmas tree is a primary barrier. In wireline operation the Xmas tree is regarded as part of the secondary barrier. If the barrier is to be “triggered” the wireline must first be cut. During coiled tubing and pressure tubing operations the Xmas tree forms only a part of the envelope or total system.

Cement plugs

Cement plugs are used to shut off perforations and open holes to the reservoir. There are requirements regarding minimum lengths of cement above the highest leakage point (shoe, liner hanger, perforations).

   a) Open hole: minimum 50 m (100 m cement plug)
   b) Liner: 100 m, or plug with 20 m cement on top
   c) Top plug: min. 200 m and deeper than 50 m below the seabed.

Mechanical plugs

These are available in a large number of versions.

1.3. Fluid barriers

During drilling, oil- or water-based drilling fluids are used as the primary barrier. For a fluid to be suitable for use as a barrier, the following conditions must be satisfied:

   a) Correct specification
   b) Testing
   c) Observation.
Correct specification means that the fluid has the correct specific gravity and that it is made up of components that will provide adequate filter cake or blocking against perforation. The correct weight means that the fluid column provides overbalance vis-à-vis the reservoir pressure - while avoiding a situation in which the drilling fluid leaks out into the formation as a result of fracturing.

Testing refers to monitoring the specifications when the fluid is being weighed and pumped.

Observation means that the well should be monitored for a period (flow control) in order to satisfy ourselves that the pumped fluid is stabilising it.

### 1.4. Barrier elements

The Norwegian Petroleum Directorate (OD) does not utilise the concepts of primary and secondary barrier, but rather that of barrier elements. It is important to keep in mind the whole system (the envelope when we are looking at the components that are intended to give us control of pressure. In day-to-day usage, we speak of barriers in connection with the BOP, Xmas tree, downhole safety valve, etc., while it is the complete system, i.e. all its elements, that must be included in the picture when we are considering operational safety.

### 1.5. Testing barriers

Barriers should normally be tested for both inflow and pressure integrity.

An inflow test is performed by reducing the pressure on the upper side of the barrier to a lower value than that on the lower side of the barrier. We then observe the pressure for a certain period of time in order to detect any leaks.

Pressure testing of a barrier is performed by increasing the pressure to a value higher than that on the lower side of the barrier. We then observe the pressure for a period of time in order to detect any leaks.
The test pressures utilised in barrier testing will depend on which phase of the well’s life cycle is involved:

a) Well construction  
b) Completion  
c) Operational phase: production  
d) Operational phase: well operations (WL, CT, snubbing, pumping)

The point of pressure tests is that they should reflect the lowest and maximum expected pressure in the phase concerned.

1.6. Examples
2. WELL INTEGRITY

2.1. API definition of pressure classes

API’s pressure classes are based on working pressures of 2M, 3M, 5M, 10M, 15M and 20M. M stands for 100 psi.

The design test pressure in connection with production/completion of the equipment is 2 x working pressure up to and including 10M equipment. For 15M equipment the test pressure is 1.5 x working pressure and for 20M equipment it is 1.25 x working pressure.

When equipment is being installed, and during the operational phase, equipment is leak tested to the given working pressure. In some cases this test pressure can be unreasonably high and the equipment is tested to the highest pressure that it is expected that the equipment will have to withstand.

2.2. Pressure

2.2.1 Hydrostatic pressure

The hydrostatic pressure of a column of fluid is determined on the basis of the density of the fluid (kg/l) and the true vertical height (TVD) of the column over the point involved.

\[ P_{\text{HYDROSTATIC}} = 0.0981 \times P_{\text{FLUID}} \times \text{TVD} \ (\text{BAR}) \]

Density is expressed either as g/cm³ or as relative density. Relative density refers to the relationship between the density of the fluid and the density of fresh water (1000 kg/m³, kg/l, etc.).

2.2.2 Static wellhead pressure

Static wellhead pressure is the stabilised pressure in the well when it has been shut in.
When a well is shut in the flow velocity and turbulence of the well fluids fall to zero, and liquids, gas and any solid matter will separate out as a result of gravitational forces.

At the interface between oil and gas we have thermodynamic equilibrium and a continual exchange of molecules between the gaseous and liquid phases. The pressure that we find at this interface is called the boiling point of the liquid or its saturation pressure.

The pressure equilibrium in a shut-in well is given as follows:

\[ P_{\text{STATIC}} = P_{\text{FORMATION}} - (P_{\text{LIQUID}} \times 0.0981 \times TVD_{\text{LIQUID}} + P_{\text{GAS}} \times 0.0981 \times TVD_{\text{GAS}}) \]

The vertical depth to the formation is given by:

\[ TVD = TVD_{\text{LIQUID}} + TVD_{\text{GAS}} \]

TVD\text{\textsubscript{gas}} and TVD\text{\textsubscript{liquid}} are given by the boiling point of the liquid and the shut-in pressure of the well.

A) \[ TVD_{\text{GAS}} = \frac{(P_{\text{BOILING POINT}} - P_{\text{STATIC}})}{(0.0981 \times P_{\text{GAS}})} \]

B) \[ TVD_{\text{LIQUID}} = TVD - TVD_{\text{GAS}} \]
2.2.3 Flowing wellhead pressure

When a well is being produced, the “flowing wellhead pressure” is read off from the Xmas tree. If we open the choke between the Xmas tree and the manifold the flowing wellhead pressure will be reduced and the production rate increases. The opposite happens when we choke the well flow.

The flowing wellhead pressure value depends on a number of conditions:

\[
P_{\text{FLOWING}} = P_{\text{PERF}} - 0.0981 \times \text{KG/L} \times \text{TVD} - P_{\text{FRICTION}}
\]  

(1)

\(P_{\text{PERF}}\) is the pressure that we find outside the perforations at any given well-flow rate. Between the pipewall and the liquid there will also be frictional forces \(P_{\text{FRICTION}}\), which will increase with production rate \(Q\).

The rate of flow that the formation yields is given by the productivity index \(PI\), which is defined as follows:

\[
PI = \frac{\text{partial P}}{\text{Q}} \text{ (bar/m}^3\text{/day)}
\]

Partial \(P = P_{\text{formation}} - P_{\text{perf}}\)

Rearranging the expression slightly gives us:

\[
P_{\text{perf}} - P_{\text{formation}} = PI \times Q \quad (2)
\]

Inserting (2) into equation (1) gives us:

\[
P_{\text{flowing}} = P_{\text{formation}} - PI \times Q - 0.0981 \times \text{KG/L} \times \text{TVD} - P_{\text{friction}}
\]

The flowing wellhead pressure is thus dependent on:

- the formation pressure \(P_{\text{formation}}\)
- the productivity index of the formation (if PI < 10 productivity is regarded as rather poor; if PI > 60 - 60 it is regarded as good)
- the flow rate \(Q\) (the degree to which we choke the well-flow)
- the lift height (TVD) and type of liquid
2.2.4 Circulation pressure

In this section we look at the complete pressure circuit between the pump and the return of fluids downstream of the choke. We assume that circulation is taking place through the workover string or through the completion string, with return via the annulus.
The pressure at the bottom of an open string will be:

\[ P_{\text{BOTTOM}} = P_{\text{PUMP}} + 0.0981 \times \text{KG/L} \times \text{TVD} - F_{\text{FRICTION}} \]

If we look at the annulus side and ignore the choke for the moment \( (P_{\text{surface}} = 0) \), we can set up the following expression for the pressure at the bottom of the well:

\[ P_{\text{BOTTOM}} = 0.0981 \times \text{KG/L} \times \text{TVD} + F_{\text{ANNULUS}} \]

If we include the choke at the surface, we can set up the following relationship:

\[ P_{\text{BOTTOM}} = 0.0981 \times \text{KG/L} \times \text{TVD} + F_{\text{ANNULUS}} + F_{\text{SURFACE}} + F_{\text{CHOKE}} \] (2)

Combining equations (1) and (2) enables us to set up the following expressions for the pump pressure:

\[ P_{\text{PUMP}} = F_{\text{FRICTION}} + F_{\text{BIT}} + F_{\text{ANNULUS}} + F_{\text{SURFACE}} + F_{\text{CHOKE}} \]

This expression was probably not completely unexpected - given that the pumping pressure needs to overcome friction all the way round the circulation loop. If we wish to obtain a given downhole pressure, this is controlled by the choke and the inlet pressure of that valve \( (P_{\text{surface}}) \).
Pore pressure/fracture pressure

Pore pressure is the third type of pressure of importance for the maintenance of well integrity. Pore pressure, or the fluid pressure in the formations through which the well passes, represents an external counterforce to the pressure that we find inside the well. The pore pressure will normally be stable and constant, though leakages through badly executed cement jobs or from the reservoir, the fracture zones, for example, may change this.

If we increase the pore pressure the formation will sooner or later fracture. This fracturing pressure is important during integrity testing. When we test a casing (e.g. during a re-completion job or P & A), it is necessary to maintain a completion pressure inside the casing that is higher than the fracturing pressure in the formation on the outside, in order to be sure that the casing maintains its integrity (i.e. is tight).

U-tubing pressure

If we change the density of fluids during circulation this will cause U-tubing pressure. U-tubing pressure is a static imbalance between the pressure in the annulus and the tubing side. The U-tubing pressure expresses itself in changes in pumping pressure - which will be a function of how much fluid has been circulated in.

The downhole pressure will also change during the circulation process when fluids with different densities are being displaced.

If we wish to circulate with “constant downhole pressure” we need to circulate through a surface choke, regulating the pressure as a function of the volume pumped.

Example:

We wish to circulate down fluids with a specific gravity (SG) of 1.25 in a well whose SG is 1.03 and with constant downhole pressure. The annulus capacity is 20 l/min, and the capacity of the tubing is 5 l/min. The well is vertical and is 1000 m deep.

What will be the maximum U-tubing pressure?

\[
P = (1.25-1.03) \times 0.0981 \times 1000 = 21.6 \text{ BAR}
\]

What happens to the pumping pressure when the heavy fluids are circulated down?
If friction in the circulation system is less than 21.6 bar, the pumping pressure will fall to zero before the heavy fluids reach the bottom of the tubing.

How should the well be choked in order to maintain constant downhole pressure?

1) The first step is to exert a pressure on the well that corresponds to the U-tubing pressure = 21.6 bar.

2) Start up the circulation (displacement) at the same time as the choke is opened - and maintain a constant pressure of 21.6 bar on the choke until the heavy fluid has reached the bottom of the string (pumped volume = 5 l/min x 1000 m = 5 m$^2$).

3) From the point at which the annulus starts to fill up until it has been topped up with new fluid, the choke must gradually be opened to the fully open position. In purely practical terms, this is done by maintaining a constant pumping pressure (from 2) throughout the final phase - by opening the choke whenever the pumping pressure shows signs of falling off.

When we have started using a new fluid with a different density, we can see that the pumping pressure changes. The following formula gives us the new pumping pressure given the same pumping rate:

\[
P_{\text{new pump pressure}} = \left( \frac{\rho_{\text{new density}}}{\rho_{\text{old density}}} \right) \times P_{\text{old pump pressure}}
\]

If the perforations are accessible it will be useless to apply pressure to the well - depending on the injectibility properties of the reservoir, the pressure will rapidly disappear.

When circulation is taking place in an open well, control of volume is essential. If the rate of flow on the return side is higher than that on the pumping side, this means that the well is producing as well as circulating fluid. If we do not want such production, we must choke the well until we find the balance between flow-rate in and flow-rate out.
2.3. Volume

2.3.1 Tubing capacity

This capacity can be calculated as follows:

\[ K = A \times \frac{L}{L} = \pi \times \frac{(ID)^2}{4} \times \frac{L}{L} = \pi \times \frac{(ID)^2}{4} \]

A: Internal cross-sectional area
L: Unit length of tubing (1 m)

i.e. we (1) calculate the volume of 1 m of the tubing, then (2) divide the result by 1 m to get the answer, e.g. 0.5 m³/m or 500 l/m.

If the ID of the tubing is given in inches, dimensions must be multiplied by 0.0254 to obtain the ID in metres.

If we wish to have the answer in litres/metre, we multiply the answer in m³/m by 1000.

2.3.2 Annulus capacity

Here we proceed as above, but we need the ID of the outside pipe and the OD of the inner pipe. The expression for calculating the capacity of the annulus then becomes:

\[ K = \pi \times \frac{((ID_{OUTER})^2 - (OD_{INNER})^2)}{4} \]
2.3.3 Buoyancy

Buoyancy is equivalent to the weight of the displaced fluid.

If a pipe is submerged in a fluid, its apparent weight will be reduced. The weight will be at its lowest when the complete pipe is submerged.

The reduction in weight is calculated in the same way as annulus capacity. We first calculate the volume of steel of the pipe:

\[ V = \pi \times \left( \frac{(OD)^2 - (ID)^2}{4} \right) \times L \quad (M^3) \]

The weight of the displaced fluid will be a function of the density of the fluid \( \rho_{\text{fluid}} \) in which the pipe is submerged.

\[ O = V \times \rho_{\text{fluid}} \quad (KG) \]

If the pipe is closed at the ends the procedure for calculating its buoyancy is somewhat different:

First we calculate the volume of the whole pipe that is to be submerged in the fluid.

\[ V = \pi \times \left( \frac{OD^2}{4} \right) \times L \quad (M^3) \]

The buoyancy is then given by:

\[ O = V \times \rho_{\text{fluid}} \quad (KG) \]
The pipe will be capable of “floating” if the following non-equivalence is fulfilled:

\[ O > \text{weight of pipe in air} + \text{weight of medium inside pipe}. \]

2.3.4 Tripping in and out of wells with tubing

“Tripping” is the expression used when we go into or out of a “dead” well. If the well is under pressure, we “strip” in or out of it.

When we go into a dead well we must be in a position to drain out the same quantity of fluid as the displaced volume of tubing (string, wireline, etc.). If this is not possible, the pressure inside the well will gradually build up, and sooner or later it will become impossible to run any further into the well.

When we exit a dead or shut-down well we must similarly fill up the well with a volume equivalent to the steel that we remove, in order to maintain its pressure integrity.

The reduction in hydrostatic pressure that results from pulling tubing with a closed end (e.g. coiled tubing, pressure tubing, etc.), is:

\[
\text{PARTIAL } P_{\text{wet}} = 0.0981 \times \rho_{\text{fluid}} \times \frac{(\text{CAPACITY}_{\text{tubing, closed}})}{(\text{CAPACITY}_{\text{completion string}} - \text{CAPACITY}_{\text{tubing, closed}})}
\]

The reduction in the hydrostatic pressure pressure that results from pulling tubing with an open end (e.g. completion string, etc.), is:

\[
\text{Partial } P_{\text{dry}} = 0.0981 \times \rho_{\text{fluid}} \times \frac{(\text{Capacity}_{\text{tubing, steel}})}{(\text{Capacity}_{\text{completion string}} - \text{Capacity}_{\text{tubing, steel}})}
\]
In a live well we usually strip in without bleeding down. This means that we make an injection into the reservoir equivalent to the volume of steel that is run into the well. When we pull out of the well we are left with production equivalent to the same volume. If we do not want this production the well can be pumped out at a rate equivalent to this “steel displacement”.

2.4. Testing

2.4.1 Testing during production or completion

This section deals with pressure-control equipment

Pressure-control equipment is always tested during assembly (factory testing). The test pressure employed is normally much higher than the working pressure that the equipment will experience during operation. The point is to verify that no latent leakage points exist. According to the API the requirement regarding test pressure is that it should not result in permanent damage to any part of the construction (the safety factor vis-à-vis such permanent damage must be at least 1.2).

<table>
<thead>
<tr>
<th>Working pressure</th>
<th>Test pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>2M</td>
<td>4M</td>
</tr>
<tr>
<td>3M</td>
<td>6M</td>
</tr>
<tr>
<td>5M</td>
<td>10M</td>
</tr>
<tr>
<td>10M</td>
<td>15M</td>
</tr>
<tr>
<td>15M</td>
<td>22.5M</td>
</tr>
</tbody>
</table>

2.4.2 Leakage tests

During well operations, pressure-control equipment is rigged up on top of the Xmas tree. Once the equipment has been rigged, and before it is opened to the well, it must be tested for leakages.

Operators are required to test pressure-control equipment to working pressure every time the equipment interface is penetrated (e.g. a wireline lubricator which is installed every time we enter the well with a perforation gun.)
Pressure-control equipment is normally tested to working pressure - even if the equipment adjacent to the pressure-control equipment is rated to a lower pressure (e.g. test separator, annulus).

2.4.3 Well testing

When a well is being constructed, each casing section or packer is tested separately in order to ensure that the equipment will maintain its integrity (verified strength) when the next section is being drilled and during the operational lifetime of the well.

Testing should preferably be performed in the direction of leakages. In a well, the reservoir and reservoir pressure are the point of departure when inflow tests are being evaluated.
Examples

The size of pressure tests/inflow tests will be a function of the reservoir and the maximum pressure that is expected to occur within the well. NB! Particularly in gas-injection wells and VAG wells which are operated at high temperatures and pressures.

- **Cased hole well, pressure tested with mud or water.** Is subjected to inflow-testing when the well is displaced from mud to seawater (washing).

- **P & A: Cemented liner;** is pressure tested in order to verify its resistance to future leakages (NB! Leak-off at shoe).

- **Perforated liner and deep plug.** The plug is inflow- and pressure-tested in order to verify its integrity (barrier function).

- **Production packer as barrier element is pressure tested from underside = inflow test.**

- **Pressure test of annulus provides inflow test of tubing hanger, pressure test of CSG (secondary barrier) and pressure test of production packer.**

- **Pressure test of Xmas tree = inflow test of valves and Xmas tree connection to wellhead.**
3. **VALVE OPERATION IN FLOWING WELLS**

3.1. **Valve operation**

3.1.1 Surface equipment, including choke

Well operations involve the use of “loose” rigged equipment such as:

- bridge/manifold. Plug valves (low-torque valves)
- Swivel joints
- T-pieces
- Check-valves
- Spacer spools with connections for temperature and pressure sensors
- X-overs (spacer spools between different types of connection)
- Cross-pieces
- Pup joints (4 and 10 ft. lengths)
- Loops (10 ft.)
- Choke

The connections are normally Weco type 1502 male or female. It is important to inspect the piping at regular intervals and to ensure that internal packers are subject to a fixed maintenance programme. Tubing is normally supplied according to pressure class 15,000 psi.

The “choke bridge” is one of the most important components of the systems. It exists in several different versions - there are normally two chokes on the manifold/bridge, which can be used either individually or in parallel.

3.1.2 Correct operation of surface equipment

The following guidelines should be observed:

- Rigging - double barrier principle: there must always be two barrier elements between the well and the external environment. One barrier element is a back-up for the other.
- When well injection is in process there must be a check valve on the injection line in order to prevent blow-back from the well.
- Chicksan piping must be laid on wooden blocks and secured against movement during pumping operations.
3.1.3 Types of valve

The only type of valve that has been designed to operate in various positions between fully open and closed is the choke. Other types of valve, irrespective of their principle of operation, suffer wear to some extent if they are left “half-way” open in a flowing well. The result will be a leaky valve.

**Ball valves**

These are used in many different connections. Ball valves have low pressure losses and low leakage rates. They can be operated rapidly and are not sensitive to the accumulation of pollutants. If a ball valve is used as a choke the valve seatings will soon suffer from erosion. The liquid which is locked inside the ball when the valve is closed can cause problems if the valve cannot be ventilated. Rapid opening of this type of valve can produce undesirable water hammer and underpressure in the system when it is opened or closed.

**Butterfly valves**

Butterfly valves are used in low-pressure systems in which the existence and severity of leaks are of less importance. They are often used in large-diameter pipes. Such valves require a high force for operation.

**Gate valves**
These are the most common type of valve in Xmas trees and wellheads. Gate valves are primarily used as stop valves, i.e. they are operated in either fully open or fully closed position. They are liable to suffer from vibration and erosion of the seatings and gates if they are not fully open or closed. This type of valve also has a long response time and requires a good deal of force to close it.

3.1.4 Consequences of faulty operation of valves

There exist certain destructive mechanisms which it is important to understand when a flow is being choked:

Cavitation

When the pressure in a flow that is being choked falls below boiling point bubbles will form in the flow. These bubbles will “brake” the flow and prevent the flow rate from increasing - even if the valve is opened wider. This situation is known as “choked flow”.

Restriction of flow is one aspect of cavitation. Others are erosion and vibration. When the pressure rises downstream of the valve the bubbles will collapse, resulting in high short-term pressures which may excite the valve and pipework systems. Cavitation can be avoided by selecting the appropriate valve style trim for a given application (type of liquid, range of pressures to be controlled, etc.). Noise in the vicinity of the choke is an indirect indicator of the presence of cavitation.

A good rule of thumb for chokes and incompressible fluids (e.g. seawater) is that the flow velocity through the valve should be less than 5 m/s.

Flashing

When compressible fluids are being choked (e.g. two- and three-phase flows) the pressure reduction across the valve may cause gas components to be released from the fluid mixture, a process known as flashing.

In multiphase flow, droplets of liquid are often carried along by the gas. Such flows may result in severe flow-induced corrosion.

Sand erosion

Sand carried along by the hydrocarbon flow is normal, particularly when it is produced from underconsolidated reservoirs. Impacts of sand particles will erode the metal in valves. Sand particles larger than 0.1 mm in diameter have the most severe effects.

3.2. Shutting in Xmas trees
3.2.1 Correct shutting in

During well operations, the local hydraulic pump is connected to the DHSV and the hydraulically actuated master valve. This pump must be monitored continuously during the operation.

Both the hydraulic master valve and the DHSV are fail-safe closed, i.e. they close automatically in the event of failure of the hydraulic pressure supply, for example.

Both valves can be closed when the flow through the valve stops. This means that the pump must be closed (during injection) or the choke closed during back-production/circulation.

In an emergency situation the hydraulic (or manual) master valve must be closed first, before the DHSV is closed.

When valves in the Xmas tree are being opened, we must first make sure that the pressure across the valves has been equalised. If we forget to do so, the valve may become “pressure locked”.

3.2.2 Consequences of faulty shutting in

The most serious error one can make is to close the DHSV while the well is back-flowing. This can seriously damage the flapper or swinging plate in the valve, with the result that we suddenly lack this barrier, either because the valve has been completely destroyed or because it leaks too much.

Other errors include incomplete closure (swab valve and lower master valve) with the result that equipment being run in and out of the well damages the valve. Incomplete closure can also result in cavitation and/or vibration of the gate, destroying packer rings and making the valve leaky when that side of it is closed.
4. METHODS OF PRESSURE CONTROL

4.1. Pumping rate during killing

4.1.1 Parameters which affect pumping rate

We can divide the parameters that influence the pumping rate into four groups:

a) fluid
b) geometry
c) design and construction
d) formation

Fluid-related parameters:
- viscosity
- density

Geometry-related parameters:
- inner diameter of pipework
- roughness of pipewall
- length of piping system
- cross-sectional area of piping (ID of tubing or DP) relative to area of annulus (ID casing relative to OD of tubing or DP)

Design and construction parameters:
- maximum pumping pressure
- design capacity of tubing or DP
- temperature limitations
- receiving system (test separator)
- downhole equipment

Formation-related parameters:
- injectivity
- fracturing pressure
- permeability.
4.1.2 Fluid related parameters

A thick, viscous liquid will be heavier to pump than a light liquid, e.g. oil or water. Viscous liquids are often utilised ahead of kill fluid in order to prevent the kill fluid mixing too much when the well is to be killed.

The density of the liquid will directly affect pumping rate/pressure. If we wish to maintain the same pumping rate, the pumping pressure must be raised by an equivalent amount.

\[ P_2 = P_1 \times \left( \frac{\rho^2}{\rho^1} \right) \]

\( \rho = \) ORIGINAL SPECIFIC GRAVITY, PUMPING PRESSURE \( P_1 \)

\( \rho^2 = \) NEW SPECIFIC GRAVITY, NEW PUMPING PRESSURE \( P_2 \)

4.1.3 Geometry-related parameters

When we pump a fluid through a pipe we experience a pressure drop due to friction. Reduced inner diameter, increased roughness and greater length of pipework all tend to increase the friction. If we wish to maintain the pumping rate under such conditions, the pumping pressure will have to be increased.

The size of frictional losses will also be related to pumping rate. In fluid mechanics, expressions such as “laminar”, “transient” and “turbulent” flow are all used. Under laminar flow conditions, the “water” flows parallel to the pipewall, while in turbulent flow the water molecules are thrown around in complete disorder with respect to the pipewall geometry. If we gradually increase the rate of flow through a pipe we see that the frictional losses are reduced at the beginning of the turbulent region, compared to what we measured in the laminar/transient region.

Pressure drop (or increased pumping pressure to maintain a constant pumping rate) can be calculated using Moody’s Friction Factor Diagram. This is based on empirical data that have been gathered for a range of roughnesses.

The input used in the diagram consists of relative roughness and the Reynolds number.
RELATIVE ROUGHNESS: \[ E = \frac{K}{D} \text{ (MM/MM)} \]

\[ k = \begin{align*}
0.26 \text{ mm (cast iron)} \\
0.15 \text{ mm (galvanised iron)} \\
0.045 \text{ mm (commercial steel)} \\
0.0015 \text{ mm (drawn steel piping)}
\end{align*} \]

REYNOLDS NUMBER: \[ R_E = \frac{\rho \times v \times D}{\mu} \]

\[ \begin{align*}
\rho &= \text{density of the fluid (kg/m}^3) \\
v &= \text{flow velocity (m/s)} \\
D &= \text{INNER DIAMETER OF PIPE (M)} \\
\mu &= \text{DYNAMIC VISCOSITY (NS/M}^2) \\
\end{align*} \]

Moody’s Diagram helps us to find the friction factor, \( f \), and the pressure loss \( P \) (= pumping pressure required) from the following expression:

\[ P = F \times L \times \rho \times v^2 / 2 \times D \]
If we wish to find the pressure drop in the annulus, the diameter D is replaced by the following expression:

\[
\text{where} \\
R_1 = \text{inner radius of casing} \\
R_2 = \text{outer radius of tubing/drill-pipe}
\]

4.1.4 Design and construction parameters

For any given pump, the rate at which the pump can deliver is related to the pump’s design pressure. Pumps are normally fitted with a “pop-off” safety valve: if the pressure rises too much (e.g. in the event of a blockage arising in the pumping system, or a sudden counter-pressure) the pop-off valve will open. The set point for the pop-off valve thus defines the maximum pumping pressure.

Another limitation in pumping rate may be the design capacity of the surface equipment and the completion/downhole equipment. It is obvious that we do not wish to raise the level of risk in an already “stressful” situation such as killing a well, by risking bursting or destroying the equipment in order to inject the kill fluid.

In some cases, the previously determined “test pressure” may be the limiting factor. If the well is equipped with 345 bar equipment - and the equipment has been tested to 270 bar during the initial completion process - then 270 bar should be the maximum working pressure of the equipment during the operational phase.

When kill fluid is being circulated in the well, freezing of the return fluid in the topside choke or ‘low torque valves” used for choking may mean that the flow rate has to be reduced. This may be an important factor when the pressure on the inlet side of the choke is high.

Test separators often require a certain proportion of gas to drive the fluid on to the first-stage and second-stage separators. In the event of back-flows of base oil or water to the test separator, it is important to control the liquid level in the separator so that the system is not shut down as a result of a “high ?? high” alarm, which would stop the whole kill operation.
Some equipment components - particularly those made of stainless steel - become brittle at low temperature (-20° C). It is important to check the circulation systems in such components before starting a kill operation.

4.1.5 Formation-related parameters

When a well is being killed, the most important aim is to “seal off” the hydrocarbons in the formation from the killing fluid in the well. When we use drilling mud as a killing fluid this happens automatically, in that the mud (which is under higher pressure than the formation pressure) is forced out through the perforation channels, forming a isolating filter cake.

In other cases, we might utilise clear killing fluid and a kill pill (e.g. salt) which is forced (squeezed) into the perforation tunnels. The kill pill can subsequently be removed by circulating seawater through the perforation zone, or by creating an underbalance in the well.

Various parameters are important if a well is to be killed properly. If the killing fluid (perhaps supported by a kill pill) is to be circulated down to the perforations, the formation properties as such are less important. In fact, it may be an advantage if the formation has low permeability, or even has deposits in parts or the whole of the perforation zone.

If the method of killing chosen is bullheading, we can pump at a rate equivalent to the injectivity of the formation, i.e. an injection rate that does not result in fracturing of the formation.

Injectivity = partial P / partial Q / day

When the kill pill or the mud reaches the perforations, this can be observed via the pumping pressure, which will rapidly increase. We can then choose to stop pumping - and check that the well is stable (topside pressure will fall less than the given value) - or continue to pump until the formation fractures. This will weaken the formation strength - but need not necessarily result in problems in killing the well. An overbalance of 10 bar is normally enough to isolate the perforations, and this is normally far from the “leak-off” point of the formation.
4.2. Methods of killing

4.2.1 General

The need to kill a well may arise from a planned or unplanned operation. The simplest method of doing so is normally by circulation. This in turn requires that the circulation is carried out as close to the formation as possible.

Some completions have built-in sliding sleeves and side pockets close to the production packer that can be opened using wireline or coiled tubing equipment. We can also enter the well with a perforation gun or tubing puncher to perforate the completion string.

If we do not wish to destroy the perforation string we can use coiled tubing or pressure tubing as the circulation method.

Killing involves circulating killing fluid in the well (and if possible, maintaining a constant downhole pressure). The downhole pressure must be higher than the formation pressure in order to prevent simultaneous production from the formation.

NB! During circulation via coiled tubing or pressure tubing it is the pressure on the annulus plus annulus friction that acts on the formation. In reverse circulation it is the pressure inside the completion string (on the inside of the perforations, side pocket) plus friction in the completion string that act on downhole pressure.

Before a well is killed a “kill sheet” must be filled out, on which the formation pressure, fluids in the well and completion geometry are used as the basis of the operational plan for the kill procedure.

It is important that the killing fluid should be compatible with the formation and the formation fluid. Use of unsuitable, non-compatible fluid may damage the formation (swelling of clays and calcium, deposits, etc.) and result in reduced production.
4.2.2 Circulation

Circulation may be employed as a killing method when we have tubing down to the formation (coiled tubing or snubbing tubing) or via the completion string/annulus. Friction in the circulation system must be overcome by the pump.

Example:

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circulation with</td>
<td>1000 l/m</td>
</tr>
<tr>
<td>Pumping pressure:</td>
<td>280 bar</td>
</tr>
<tr>
<td>Xmas tree pressure:</td>
<td>275 bar</td>
</tr>
<tr>
<td>Pressure in string:</td>
<td>180 bar</td>
</tr>
<tr>
<td>Downhole pressure:</td>
<td>150 bar</td>
</tr>
<tr>
<td>Topside choke pressure:</td>
<td>0 bar</td>
</tr>
</tbody>
</table>

- Pressure drop in topside system: 280 - 275 = 5 bar
- Pressure drop in tubing: 275 - 180 = 95 bar
- Pressure drop across bit: 180 - 150 = 30 bar
- Pressure drop at annulus: 30 - 0 = 30 bar

It is important to note the pressure drop at the annulus. This is the only pressure that the formation will “see” during circulation - the remainder of the pumping pressure will disappear in the form of friction or heat during circulation.

Circulation can be done the long way round or we can reverse circulate. When we circulate the long way round we pump down the tubing and up the annulus. This is the most usual method, and it is the only way to pump when we are using coiled tubing and snubbing (because of the check valves in the bottom hole assembly). If we kill the well via the perforation string (punched hole or via the completion equipment) we can reverse circulate (down the annulus and up the completion string).

We should be aware of two problems involved in pumping the long way round:

a) If we try to enter the well through sand (e.g. by sand-washing) and try to lift the sand out, this may lead to lost circulation (the annulus pressure becomes so high that the formation fractures).

b) If we lift out sand, deposits, milling debris, etc, from the well and the pump has to be stopped, there is a high risk of getting stuck.

Another scenario is the circulation of brine down the tubing via circulation equipment in the completion ?? wall // string ?? and up via the annulus. If the well below is open we...
run the risk of getting hydrocarbons mixed with the brine and in the annulus, as well as a risk of hydrate formation.

Reverse circulation is an attractive way of bringing up dirt and debris from the well, as the capacity of the completion string is usually much less than that of the annulus, i.e. the flow velocity in the tubing will be much higher than in the annulus. This may mean reduced requirements with regard to pumping capacity and a lower risk of sticking.

In well that have been perforated in several zones, cross-flows will be normal during shut-in. The zones with the highest pressures will produce to zones under lower pressure. Somewhat similar problems may be experienced on killing with loss (or injection) from one zone while we continue to produce from another. However, this type of well may require the temporary shut-in of the “thief” zone (with salt or carbonate particles) in order to permit circulation or reverse circulation.

Killing a well by circulation down the completion string, e.g. via perforations, with return via the annulus, has a number of weaknesses. The well fluids must be compressed and it may be difficult to maintain control of well pressure before the kill fluid has reached the perforation zone/circulation zone in the completion string. If the pumping rate has been too low during the first phase of the operation, the kill fluid will mix with the well fluids, making the topside choke process less predictable.

Killing the well via the completion string should be done by means of reverse circulation. A slight uncertainty remains, given that, because of its weight, the completion fluid may be injected into the formation before the perforations are packed with kill fluid, i.e. there will be some uncertainty on the return/choke side as to what we are getting in return, and when we are getting it.

If we are using coiled tubing or pressure tubing we need to employ normal circulation because of the check valves in the string. When we enter the well we fill the string with water or kill fluid (in order to prevent the string from collapsing). Starting the pump immediately starts the killing process. The killing operation is thereafter controlled by adjusting the choke valve.
Production tubing pressure

Start pumps (string full of kill fluid)

Well dead: stop pumps

Pumps run up

Wellhead pressure

Well dead

Annulus pressure
4.2.3 Reverse circulation

In reverse circulation the fluid is pumped down the well annulus and returns up the completion string. The operation is controlled via the choke, which is on the return side (downstream killwing).

This method is often preferred since communication between annulus and tubing can be established at an acceptable depth. This allows us to avoid entering the well with coiled tubing or pressure tubing, both of which are relatively expensive in comparison with wireline - where we punch/perforate holes or open the sliding sleeve in the completion string above the production packer.

When the kill fluid is circulated into the completion string there is always a risk of the fluid carrying along hydrocarbons from the zone below the circulation point. This tendency can be reduced by raising the viscosity of the kill fluid.

In calculating the kill curve we need to take into account the fact that the weight of the completion fluid in the annulus will normally differ from that of the kill fluid.

NB! In formations whose pressure is much lower than the initial pressure the liquid in the annulus may place too high a loading on the formation, with the result that we are unable to establish circulation up the completion string before the lighter kill fluid enters the same string.
4.2.4 Bullheading

Bullheading is a method of killing a well that requires open perforations. It is also the kill method that produces the highest topside pressure and the highest pressure vis-à-vis the formation, without this necessarily being a problem.

We often start the kill process by injecting one or two wellhole volumes of seawater down the completion string. Using seawater, we can maintain a high rate of pumping and displace most of the hydrocarbons back into the formation. In the second phase we pump down kill fluid which is normally both heavier and more viscous, i.e. it is more difficult to pump and thus to maintain a high rate of displacement.

Generally speaking, we need a flow-rate of 1 m/s to displace gas (if we calculate this on a theoretical level we come down to a figure of 0.3 m/s, depending on the type of gas involved and other conditions.

Example

1. Calculate the pumping rate required

TUBING: 5 1/2”, 17# ID=124,3 MM

CROSS-SECTIONAL AREA = Π X (ID)^2 / 4 = 0,0121 M^2

MIN. FLOW-RATE: V = 1 M/S

FORMULA: V = Q/AQ = V X A = 1 M/S X 0,0121 M^2 = 0,0121 M^3/S

= 12,13 LITER/S = 728 LITER PR. MIN (LPM)

2) Calculate the additional pressure required on the outside of the perforations to get 728 LPM in

We assume that the formation has an injectivity of 60 m^3/bar/day.
In this case, \( Q = 728 \text{ LPM} = 728 \times 1.44 = 1048 \text{ m}^3/\text{day}. \)

Formula: \( II = Q / \text{partial P}/d \)
\( \text{partial P} = Q / II = 1048/60 = 17.5 \text{ bar} \)

I.e. for a well whose injectivity is as high as 60, a pressure of only 17.5 bar is required on the outside of the formation to obtain an injection rate of 728 LPM.

If we carry out the same calculation for a low permeability whose injectivity is only 5, we get the following result:

\( \text{Partial P} = Q / II = 1048/5 = 210 \text{ bar}. \)

It may be necessary to fracture low-permeability formations. To do so, we allow the pumping pressure to rise until it suddenly flattens out. We then maintain this pressure until the kill fluid has been got down. Once this has happened the pressure can be reduced and the cracks into which we have been pumping will close again. The kill fluid is in place and everything is OK.

Some theoreticians claim that fracturing may lead to irreversible losses in the formation - i.e. that the kill fluid will disappear into the formation and that sand/mud or coarse LCM (lost circulation material) will have to be injected to stop the leakage. Problems of this sort must be resolved before the kill operation commences.

Other problems that need to be cleared up in advance are:

- Pressure capacity of the equipment employed
- Use of ?? inhibited // inhibition ?? pill ahead of the kill fluid
- Pressure loss in thin completion strings
- Minimum rate in large completion strings (in cases of poor separation between the kill fluid and well fluid, killing may take a long time)
- Sand/debris in horizontal sections of the well (when we reverse the direction of flow, as is done during a killing operation, we may experience a blockage vis-à-vis the formation before the kill fluid is in position.

### 4.2.5 Bleed-off/lubrication

Bleed-off/lubrication is a method that can be used when:
• circulation is impossible (we cannot enter the well as a result of a restriction)
• bullheading cannot be employed as it would result in excessive topside pressures.

This is often utilised as a starter method to reduce pressure at the surface, and is followed by bullheading.

The lubrication method is based on bleeding off a certain amount of pressure and pumping in an equivalent quantity of kill fluid. The kill fluid will fall to the bottom and gradually build up a column of kill fluid in the perforation zone, i.e., for each injection of killing fluid the shut-in pressure should fall by a given amount. Since the gas necessarily has to migrate through each injection of kill fluid sufficient time must be allowed for this to happen before we bleed off again and inject a new “pill” of kill fluid.

Gas is capable of migrating through a non-viscous liquid at speeds of up to 600 m/h. This process will take a longer time in viscous fluids.

Killing a well by the lubrication method may take several days.

5. PROBLEMS

5.1. Free gas in the well

5.1.1 Bleeding off gas (Joule-Thomson Effect)

When we have flow through a pipe or a valve we may find that the temperature of the flowing medium is lower than the ambient temperature. The difference between the ambient temperature and the temperature of the flow is known as the Joule-Thomson Effect.

When gas pressure falls (through a pipeline or across a valve) the gas expands and loses energy. If the expansion of the gas takes place with constant enthalpy (H = U (internal energy) + pV (pressure x volume) = constant), some of the energy will manifest itself as a reduction in temperature due to the lower pressure.

Normally, temperature falls by about half a degree Celsius per bar of pressure drop, i.e. 100 bar pressure drop will produce a 50 degree fall in temperature.

NB: bleeding off gas at low temperature, with a large pressure drop and low outlet pressure may result in brittle fracture in pipelines and other equipment. Stainless steel may suffer from brittle fracture at temperatures as “high” as -20° C.
5.1.2 Gas migration

In the course of well operations it is usual to displace the well with seawater, which does not provide a stable “seal” against the formation, with the result that hydrocarbons and/or gas will gradually migrate to the surface. In order to keep the gas away we normally after-pump at a rate, for example of 100 lpm, either continuously or periodically while the workover is in progress.

Gas that migrates to the surface - in connection with uninhibited seawater - may produce hydrate problems. We often notice an increased “drag” in the equipment when we are pulling out of a well (above the DHSV) or we may observe plugging in the surface equipment itself. Occasionally, the well may become blocked - this is a serious matter and means a risk of several days to even months of delay before the well returns to the state it was in before the well operation.

5.1.3 Bullheading gas

Wells that are being shut in stabilise fairly quickly, with the gas on top, followed by an oil phase and an aqueous phase at the bottom. A test performed on a Gullfaks well a few years ago (above a closed DHSV) showed the phases to be in stable equilibrium after 30 minutes.

Gas bullheading requires a good flow rate and inhibited fluid ahead of the gas. It is good practice to inhibit the volume down to the safety valve (this valve is normally installed so deep that the temperature will prevent hydrate formation). In the event of any problems during this start-up phase, the inhibited fluid will prevent the formation of hydrates if the operation has to be stopped.

It is good practice to maintain a bullheading rate of 1 m/s or more (theoretical calculations have shown that 0.3 m/s may occasionally be sufficient). This will give a well-defined fluid front during the first part of the operation, which will help to minimise the chances of hydrate formation.

When the liquid meets the gas, the latter will be compressed. This process becomes evident in the form of a major reduction in pumping pressure during the first phase of the displacement process. It occasionally happens that the gas is compressed so much that it moves into the liquid phase.
NB: pumping pressure in connection with gas-injection and WAG wells (in the gas phase) must be monitored in order to prevent formation fracture. This is due to the low gas gradient, which normally offers narrow margins against fracturing.

5.1.4 Gas + water = hydrates

Seawater is the most frequently used liquid in well operations. It is free and easily available. However, the disadvantage of seawater is that it forms a crystalline compound with gas (density 0.88 - 0.90 g/cm³ at low temperatures and high pressures.

The seawater is inhibited in order to prevent hydrate formation. We also normally use inhibited liquid during the testing of intervention equipment (coiled tubing, snubbing, wireline) before we open the equipment to the well.

5.2. Swab and surge pressure

5.2.1 Surge pressure

The expression “surge” refers to the piston power (overpressure) that arises when the downhole string is run into the well.

Surge pressure is a function of the following conditions:

- Clearance between the well wall and downhole equipment (small clearance means high pressure)
- Type of fluids in the well (completion fluid produces a higher pressure than oil/gas)
- Trip/run speed (high speed produces high pressure)
- Length of the components in the downhole equipment with largest diameter (long components produce highest pressures)
- Acceleration/retardation speed (high speed produces high pressure).

In a perforated hydrocarbon well, surge pressures will arise locally around the downhole equipment and will not result in global effects until they are close to the reservoir. In wells that are producing sand there may be sand in the horizontal part of the well, which is pushed on by or reinforces the surge effect when we enter the well.
In a scaled-over well or a well with poor injectivity, the surge pressure may produce pressure pulses that are greater than the reservoir’s fracture resistance.

In an unperforated well the effect of pressure pulses will rise the deeper we go into the well (as in the case of the piston in a bicycle pump as it is pushed in).

The consequences of surge pressure may include the activation of pressure-actuated equipment in the downhole string and circulation devices.

Entering a well also results in a general rise in pressure which leads to an injection into the reservoir, equivalent to the displaced liquid volume of the equipment.

Example: If we enter the well with a 2 7/8” string and a running speed of 250 m/h - this will result in an injection rate of 1.05 m³/h = 17.5 l/m. This can be compensated for by bleeding off via the choke (to the test separator) while we are running in equipment.

In entering an unperforated well it is particularly important to bleed off a volume equivalent to the volume displaced by the equipment. There are cases of this having been forgotten, with the result that wells have been perforated several thousand metres above the reservoir.

5.2.2 Swab pressure

Swab pressure is the piston effect that occurs when downhole equipment is pulled from the well.

The size of the swab pressure is dependent on such conditions as:

- Clearance between the well wall and downhole equipment (small clearance means high pressure)
- Type of fluids in the well (completion fluid produces a higher pressure than oil/gas)
- Trip/run speed (high speed produces high pressure)
- Length of the components in the downhole equipment with largest diameter (long components produce the highest pressures)
- Acceleration/retardation speed (high speed produces high pressure)
- The effect will be greatest when the downhole string is close to the reservoir and causes hydrocarbons to be drawn out of the reservoir
- When we trip the intervention equipment out of the well it will naturally fill up/produce a volume equivalent to that displaced by the equipment. If this is not desirable, we need to inject an equivalent volume of diesel oil or inhibited
seawater as we pull the equipment. Such a procedure is normal following gravel packing.

5.3. **String washout**

5.3.1 Snubbing string

Washout of the snubbing string is usually registered in the form of an unexpected fall in pumping pressure without a change in choke pressure.

This is a critical occurrence since the DHSVs are not capable of maintaining the well pressure for long. The pumping pressure is reduced to well pressure and the “kelly cock” valve is closed. We then start to clear the well for killing.

Washout is usually due to normal erosion caused by sand washing, but may also be caused by chemical conditions and faulty materials. Washout occurs extremely seldom.

5.3.2 Coiled tubing

Coiled tubing may fracture above or below the “injector head”.

**Break above the “injector head”**

The procedure to be followed involves stopping the coil and closing slips and pipe rams in the BOP.

If we observe that the well is flowing into the coil (leaky back-pressure valve), the shear ram should be closed, the coil pulled up by about 0.5 m and the blind ram closed. We then start to kill the well by filling the coil below the BOP with kill fluid, and the rest of the well by bullheading via the Xmas tree.

If we see that the BPV is tight, we pull the coil from the well and replace it.

**Break below the “injector head”**

This results in well pressure entering the coil so that the well has to be killed before the coil can be pulled. See preceding section: “Break above injector head”.
Coiled tubing is liable to “pitholing”. Due to the length of the coil, it may be difficult to empty it of all liquids after use (e.g. acid, chemicals, seawater). The liquids remain on the low side of the well and may corrode holes in the coil.

Welds in coiled tubing are also liable to suffer from cracks or fractures. These have always been among the most frequent fracture sites. This may also occur as a result of fatigue or collapse of the tubing when the first part of the coiled tubing has passed the stripper rubber.

5.4. Blockages in the well

5.4.1 Blockage mechanisms in wells

The blockage mechanisms we refer to include:
- Formation sand (from sand-producing wells)
- Scale
- Mechanical blockages (collapsed casings, liners, “patchers”, “straddle packers”, jammed valves and downhole strings

5.4.2 Bursting of the completion string as a result of sudden blockages

This situation may be of relevance for gas injection and WAG (Water Alternating Gas) wells. Such wells are often operated close to their design limits, with the result that they have no safety margin in reserve to cope with bursts. In the event of a sudden blockage (mechanical collapse) the safety systems will normally be unable to react before the completion string has burst. The explosive force arises from the mass energy \( \frac{1}{2} m \times v \), which is transformed from kinetic into potential energy.

We also find this effect when we run downhole strings with closed lower ends (shear disks). There have been many cases of valves and packers being set too early on their way into wells because the driller has stopped the string too suddenly.

5.4.3 Removing blockages

There are normally two ways of doing this:

a) By mechanical methods
b) By means of chemicals
Mechanical methods require the use of intervention equipment such as wireline, coiled tubing or pressure tubing equipment.

Wireline equipment can be fitted with jars or accelerators capable of breaking through obstacles such as scale (by breaking it up) or by fragmenting them in cases where we try to fish up equipment that has been lost in the well. If the blockage is caused by ice and we have an electric cable we can melt a channel through the hydrate plug with a melting tool and a pump at the end of the cable.

If we have coiled tubing or pressure tubing available we can use a jar to hit the obstacle upwards or downwards. We can also use a motor and milling machine to drill or mill a passage through the restriction. If we use pressure tubing the string can be rotated within the range of the jack stroke - normally 2 - 2.5 m - which is an effective way of cleaning the hole (though rotation also causes wear on the completion string).

Chemical methods involve pumping chemicals down to the region of the restriction. We allow the chemicals to react for a while, and produce them by the same route up again. In order to prevent the process from becoming unstable, it may be necessary to add more chemicals at the surface before the original chemicals enter the process.

5.5. Hydrates

5.5.1 Conditions under which hydrates form

The following conditions are necessary for the formation of hydrates:

- Presence of free water
- Presence of light gas molecules
- Relatively high pressure
- Relatively low temperature.

Hydrates consist of water in a crystal lattice structure mixed with light gas components. 1 m$^3$ of hydrate contains approximately 0.8 m$^3$ water and 180 m$^3$ gas.

For a stable hydrate to form, the gas needs to be saturated with water vapour (the dew-point of the water is higher than the temperature of the system).

An example of a classical case of hydrate formation is a valve located in a vertical pipe system. Above the valve, three phases rapidly form, with water at the bottom and lying on the valve. Similarly, directly underneath the valve the will be gas. If the valve leaks the gas will seep up from beneath the valve into the liquid phase above the valve, and under certain pressure and temperature conditions, hydrates may be formed.
5.5.2 Methods of removing hydrates

The following methods can be employed to remove hydrates:

- Lower pressure
- Raise temperature
- Use an inhibitor.

**Pressure reduction**

For any given temperature, we must reduce the pressure to below the equilibrium curve, so that the lattice bonds in the hydrates begin to dissolve. This process requires energy, which it takes from itself, (the temperature in the melt will fall), and the rate of melting will then be a function of how easily the hydrate plug has access to the ambient temperature. If the pipeline or vessel is insulated, the melting process will take longer than in an uninsulated pipe or vessel.

NB: in a well in which a hydrate plug has formed, reducing pressure can be risky. If the hydrate plug slips and there is gas between the plug and the surface system, the plug may shoot through the Xmas tree topside and cause a blowout (until we are able to close the DHSV).

If we have hydrates in a pipeline or vessel, the pressure must be reduced by an equal amount on both sides of the plug in order to prevent it from moving as it melts.

**Temperature rise**

We raise the temperature while maintaining constant pressure. The heat will break up the lattice structure in the plug.

NB: if the volume is constant, (i.e. if the gas that is released has nowhere to expand into), the process will stop of its own accord as the rising pressure within the enclosed volume will cause a change in equilibrium conditions. This pressure can be extremely high - up to several thousand bar.

**Use of inhibitor**

Methanol, glycol and salt can all dissolve hydrates. When these substances come into contact with hydrates, the equilibrium curve in the area of contact will change, but at the same time, the inhibitory effect will be used up. If the effect is to be maintained while the hydrates are being dissolved, inhibitor must be added either continuously or batch-wise.
5.5.3 Risks in connection with removing hydrates

As mentioned in section 5.2, dissolving hydrates within a constant volume is risky. Generally speaking, we need to ensure that it is possible to bleed off volume, i.e. to maintain control of the pressure. It is particularly important to monitor the pressure.

Removal of hydrate plug from completion string

A hydrate plug in a completion string will normally be localised above the DHSV, where the temperature is so low that hydrates can form. The DHSV is normally installed so deep that hydrates cannot form. The DHSV should be closed - even if it is not 100% tight it will reduce the energy behind the plug if the plug should work loose.

We then dissolve the plug by bleeding off gas and pumping in methanol repeatedly. This operation may require several days before the plug is dissolved. Here we have to make sure that there is always liquid between the plug and the wellhead. If the plug loosens, the liquid will immediately dampen the energy that is released, while gas would permit the plug to accelerate to an enormous velocity by the time it reaches the wellhead and Xmas tree, which of course is not very desirable.

An alternative method is to melt the plug using a melting tool and pump run in on an electric cable. The pressure above the plug is maintained at a constant level - i.e. we need to bleed off the gas liberated by the melting process. If we have a suspicion that the pressure below the plug may be higher than above it, we should inject liquid inhibitor between the plug and the topside equipment.

Removal of hydrate plug in flowing pipelines on the seabed.

In such cases we must first close the valve on the seabed and then lower the pressure on both sides of the plug in the pipeline via the service umbilical/line and the topside connection to the pipeline. We must try to reduce the pressure on both sides in order to avoid damaging the pipeline, at bends, for example, in the event of the plug loosening under unbalanced pressure conditions.

Removal of hydrate plug in topside system

The appropriate procedure is to reduce the pressure on both sides of the plug.

We can also employ heat, e.g. steam, but we must be sure that the liberated gas is capable of expanding, i.e. monitor the pressure within the volume in which the gas is liberated. NB: manometers are also capable of freezing - giving a false impression of security.
6. MANAGEMENT OF OPERATIONS

6.1. Planning before start of operations

6.1.1 General

Well operations and their planning are project-oriented. The success of a project will be a function of the quality of the planning process (use of appropriate expertise, building on previous experience, best practice), the ability to make the right decision at the right time, clearly defined interfaces, and the various parties involved accepting their own responsibilities.

Before the start of an operation an onshore start-up meeting will normally be held, where the key personnel involved in the planning process go through the operation with the “executive” personnel. Similar meetings will also be set up offshore in order to familiarise all parties with their respective tasks, roles and responsibilities during the operation.

Systems of communication must be defined, both internally at project level offshore and between the offshore and onshore organisations. The offshore operation will normally be supported by the land-based organisation. It is also usual to establish a shift-based system onshore so that key personnel can be consulted in the event of technical or logistical problems.

Activities for the coming 24 hours are identified and included in a daily plan. It is also usual to draw up plans on a longer time-scale, covering personnel, equipment and call-out times.

The well programme is supported by operational manuals which are drawn up by the operator, contractor and/or producer. Examples of such manuals include:

- Project plan/project handbook
- Well operation manual
- Installation-specific procedures
- Official requirements
- Operators’ and contractors’ procedures
- Changes and deviations
- Lists of contents
- Experience data
- Safety procedures and criteria (risk analyses, back-up plans and plans for dealing with losses of barriers).

The operator must draw the attention of the contractor to current HSE objectives and risk acceptance criteria. Safety meetings must be held offshore in order to ensure that all personnel are aware of the operational limits of the operation. This applies also to
requirements regarding barriers, pollution control, fire and explosion prevention measures and protective measures to be taken against toxic and/or hazardous environmental conditions.

On the Norwegian continental shelf, activities must be reported to the Norwegian Petroleum Directorate (NPD) on a daily basis. Applications for permission to deviate from the requirements set by the authorities must be sent to NPD for its approval. Cases of personnel injury, hazardous “near-misses” and accidents must be reported to NPD.

Good communications are important:

- “Hand-over” meetings must be held at all levels when operational personnel are replaced, at the end of shifts, coffee breaks, ?? lunch // launch ??
- Daily meetings with the shore organisation should be held, to discuss the previous 24 hours of the operation, accident/incidents, progress, requirements for materials and forthcoming activities.
- The archive for the operation should be available both onshore and offshore.

På norsk sokkel er det krav om daglig rapportering av aktiviteter til Oljedirektoratet. Ved fravik fra myndighetskrav skal egen søknad sendes til OD for godkjenning. Ved personskade, farlige tilløp og uhell skal det straks gis beskjed til OD.

God kommunikasjon er viktig:

- “Hand-over” møter bør utføres på alle nivå ved skifte av personell i operasjonen, ved skiftedring og ved kaffipauser, launch, etc.
- Daglige møter med landorganisasjon arrangeres som dekker siste 24 timer operasjon, uhell/hendelser, fremgang, material behov og kommende aktiviteter
- Arkiv system tilgjengelig både offshore og på land.
6.1.2 Emergency procedures

There are several situations in well operations which involve a change in status from a safe condition to an unsafe or emergency situation.

- The pressure in one or more annuli rises or falls drastically
- Failure of a well barrier
- Failure of intervention equipment barrier
- Gas leak in the area of the well or process equipment
- Abnormal situations (bad weather, parallel activities).

If we lose a well barrier, the well must be shut in, and compensatory measures must be implemented in order to maintain safety levels until barrier no. 2 has been established or activated.

When a well intervention is in progress and we lose the primary barrier in the intervention equipment, the secondary barrier must be activated immediately. This requires attention and a rapid response.

On certain installations all wells may be required to be shut in if a barrier in one well is lost. This will be determined by specific operator requirements, which are often related to the number and type of parallel activities.

6.1.3 Organisation - well killing

A well-kill plan is normally drawn up in advance of an operation. This plan must identify the personnel who will perform the kill operation. Under normal circumstances only a minimum number of personnel are required for the kill operation, while the remaining personnel are withdrawn to safe positions (e.g. lifeboats, muster stations).

Examples of personnel required for well killing:

- Fire chief
- Cementer (pump operator)
- Intervention equipment foreman (wireline, coiled tubing, snubbing tubing).
- Intervention equipment operator
- Operator of hydraulic pump to DHSV and hydraulic master valve
- Derrick operator.

During well operations a kill pill is often used in combination with clear kill fluid (brine) to kill the well. The kill pill is pumped down to the perforation zone and is forced into the perforations. The “squeeze” often needs to be repeated (hesitation squeeze). The column of kill fluid should be in overbalance (10 bars or more) relative to reservoir pressure in order to keep the kill pill in position. Drilling fluid can be utilised as an alternative to the brine/kill pill combination.
The well killing process may follow this sequence of procedures:

1. The kill pill is mixed and made ready.
2. X m³ seawater are pumped into the well to displace hydrocarbons in the uppermost part of the well.
3. The kill pill is pumped in.
4. The kill pill is displaced by means of killing fluid (of the correct specific gravity) at a pumping rate that is higher than the gas dispersal rate (e.g. 1000 lpm).
5. The pumping rate is lowered before the kill pill reaches the perforations (e.g. to 200 lpm).
6. The kill pill is squeezed into the perforations at a given overpressure (lower than the fracturing pressure of the formation).
7. The pump is stopped and killing is completed when the rate of pressure reduction is lower than 1.5 bar/min. If the rate of pressure reduction is higher, continue to squeeze the kill pill into the perforations and monitor pressure bleed-off.

6.6.2. Abnormal operations

6.2.1 Loss of barriers

The following is a list of examples of barriers that may fail during an operation (or during testing in advance of an operation):

- Killing fluid that loses its hydrostatic overbalance vis-à-vis the perforations/formation:
  - The kill pill dissolves and killing fluid flows into the formation
  - Killing fluid flows slowly into the formation ??
  - Barytes in the drilling mud “sags” out
- BOP
- Unperforated and cemented liner is being tested for overpressure resistance:
  - Leak in the liner shoe
  - Leak in the liner
  - Leak in the tubing hanger/packer
- Inflow-tested cement plug or mechanical plug in the casing above the perforations
- Plugs installed internally in the casing, which isolate open perforations and which have been inflow tested
- BOP valves, “ stuffing box”, “stripper bowl” for wireline, coiled tubing or pressure tubing operations
- “Safety head” located between the Xmas tree and the rigging for wireline, coiled tubing or pressure tubing equipment
- Manual and hydraulic master valves in the Xmas tree
- Production string and production packer (annular BOP) The production packer should preferably be tested in the direction: from the formation towards the surface
- Packers around the tubing hanger and annulus valves in the wellhead
- Downhole safety valve.
6.2.2 Removal of hydrates

Types of well in which we should be particularly observant regarding hydrates include the following:

- Water Alternating Gas wells (WAG)
- Gas injection wells
- Subsea wells with long flowlines
- Gas-lift wells

Example: If the DHSV has not been installed at a hydrate-free depth and the valve is leaky (the NPD requires it to be installed 50 m below the seabed), gas that leaks from the underside of the well into the aqueous phase above it may form a hydrate plug.

Removing hydrates is a risky process, which must be performed under careful control. Hydrates liberate gas as they dissolve. If the gas is unable to expand it will create a high pressure that may be capable of rupturing the vessel containing the hydrate plug.

Pressure reduction involves reducing the pressure until the plug releases gas (P₁) and bleeding off several bars pressure to P₂, waiting for a few minutes and pumping in inhibited liquid (salt, methanol, glycol) while allowing the pressure to rise again to P₁. We then wait a few minutes and bleed down again to P₂, and so on. This process is known as lubrication.

Hydrates in flowlines are removed by reducing the pressure by equal amounts on both sides of the plug.

Melting tools for operation on an electric cable are available (wireline operation). These tools are lowered down to the hydrate plug and melting commences while a pump circulates the melted liquid at the top of the plug.

We can also pump in heated fluid into a well if it is equipped with gas-lift valves - however the pressure rise in the annulus may result in even more gas in the completion string if the annulus is full of gas.

Hydrates can be dissolved by means of methanol, glycol or salt. Methanol is efficient, but it is lighter than water and thus tends to be unable to sink into the plug. Glycol (MEG, DEG or TEG) is heavier than water, but somewhat less efficient that methanol. Salt is another efficient means of dissolving hydrates. We can obtain a good effect primarily by flushing or washing the fluid into the hydrate plug. If we use coiled tubing or pressure tubing for tasks of this sort it is essential to maintain a balance of pressure above and below the plug during the washing process.
6.2.3 Forming an ice plug as a barrier

This is absolutely the last way out when we have lost one or more barriers and have been unable to replace them in order to be able to continue with the operation. This may happen in such situations as:

- Overhauling or removing the Xmas tree or BOP
- Removing jammed equipment from the BOP or Xmas tree.

The method involves forcing a mixture of fresh water and bentonite into the upper section of the well (approx. 150 - 300 m). We then pump in dry ice, which freezes the freshwater/bentonite mixture (liquid nitrogen can also be used). The length of ice plug required is given by the following formula:

\[ L = \text{OD of tubing (in)} \times \text{WHP (psi)}/1000 \]

The time require for freezing is around one hour per inch of pipe diameter. The plug is pressure tested before we begin to work on the Xmas tree or BOP. The temperature of the wellhead (ice plug) must be monitored as long as work continues over the wellhead, and the ice plug must be maintained in condition if the temperature of the outside of the wellhead begins to rise.

Dangers associated with the use of ice plugs include:

- Brittle fracture of the wellhead or its components
- Fracture of the well head due to expansion of the freezing water
- Leaks in the packers due to low temperatures.

“Hot-tapping” of the wellhead before the freezing process commences is usually also needed in order to gain access to the completion string.

6.2.4 Well killing

This is performed either as an urgent action because the situation requires it (loss of barriers, other conditions) or a part of a plan for regaining a lost barrier (e.g. as a result of re-completion).

In most cases we have plenty of time, and are able to evaluate/plan the most appropriate killing method. Occasionally we will be short of time due to marine environmental factors (e.g. when working on board a floater), explosion danger, toxic gases, etc.

Example: if there is a gas leak to the atmosphere we can pump seawater (bullheading) while we plan corrective measures to deal with the problem.
6.2.5 Leaks

By definition, barriers are tight. The IWCF does not regard the DHSV as a barrier, although it is regarded as such on the Norwegian shelf, in spite of the fact that we regard it as tight if it leaks less than:

0.4 l/min (liquid)
15 scf/min (gas)

Leaks to the atmosphere are not permitted. Small leaks which are not detected can be more dangerous than large leaks which are registered by gas detectors. When the concentration of gas rises above the lower explosion threshold - an explosion can occur.

During well operations, in the event of a leak in a primary barrier the secondary barrier is activated and this is used while we replace a packer set or re-establish the primary barrier.

6.2.6 Fire and explosion

Fires and explosions produce particularly dangerous situations, which require immediate closing of valves between the well and the fire, so that the seriousness of the fire can be limited. Such situations also require the well itself to be shut in.

If the shut-in panel is not accessible (e.g. in the case of a fire in the control cabin or if the operator has been injured), we must use the back-up panel, which should be located elsewhere (e.g. on a different deck or side of the well zone). If a wireline operation is in progress without the use of a back-up panel, the hydraulic master valve must be closed.

If the fire has due to an explosion the resulting pressure front (and the subsequent under-pressure) may cause severe physical damage. If the fire is given time to develop, equipment will become deformed and cease to function.

Wellhead equipment is normally designed to withstand an oil fire at 1000° C for one hour, before closed valves start to leak and provide further fuel for the fire.

Fires and explosions must first be reported, before action is taken to shut in equipment and then to extinguish the fire.

If the well cannot be shut in we face the risk of a blowout. The radiated heat may be so high that parts of the platform can melt down. Shutting in such blowouts requires special expertise, and it may take several months to bring the operation to an end.
7. TEST QUESTIONS: PRINCIPLES AND PROCEDURES
1. What is the definition of a barrier?
   a) A closed-off area.
   b) Something that prevents a flow of hydrocarbons from a well.
   c) A fluid in over-balance.
   d) A BOP locking mechanism.
   e) A mechanical plug.

2. Which of the following statements describe types of barriers?
   a) Positive and negative.
   b) Pump open and pump closed.
   c) Mechanical and liquid.
   d) Over-balanced and under-balanced.
   e) Primary and secondary.
   f) Upper and lower.

3. Do wells in which the oil has to be lifted or pumped out (i.e. artificial lift pumps, rod pumps) need the same control barriers as wells in which the oil flows out of its own accord?
   a) Yes
   b) No.

4. What does the term “positive plug” mean?
   a) It prevents flow from above.
   b) It prevents flow from below.
   c) It prevents flow from both directions.

5. How can a plug stop flow?
   a) By blocking the perforations.
b) By blocking the Xmas tree swab valve.
c) By providing 10 bar of over-balance.
d) By sealing the tubing hanger.
e) By isolating the well-flow.

6. How is a mechanical plug installed? (Check two answers)
   a) The well pressure closes it.
   b) The well flow closes it.
   c) By the freezing method.
   d) By wireline, coiled tubing or pressure tubing
   e) The control line pressure closes it.

7. Which of the following mechanical barriers can be installed by intervention methods? (Check six answers)
   a) Wireline plug.
   b) Pump-through plug.
   c) Circulation valve.
   d) Differential pressure valve.
   e) Pump-open plug.
   f) Expendable plug.
   g) Float valve.
   h) Retainer.
   i) Hi-vis pill.
   j) Orifice valve.
   k) Pressure-cycling plug.
   l) Check valve.

8. Which of the following is a closable barrier?
   a) Tubing hanger plug.
b) Pump-out plug.
c) BOP.
d) Packer.
e) Check valve.

9. Which of the following statements is TRUE with regard to plugs for installation in the completion string? (Check three answers)

   a) Check that the pressure rating is correct.
   b) Check that pressure has been equalised before setting.
   c) Check that a plan exists to loosen the plug if material settles out on top of it.
   d) Check that the plug will be installed as close to the Xmas tree as possible.
   e) Check that the plug maintains pressure after installation.

10. From which direction should a barrier be tested for integrity?

    a) From above.
    b) From below.
    c) In any direction.
    d) In the direction of flow.

11. What are the correct names for the barrier categories?

    a) First-line, second-line and third-line.
    b) Primary, secondary and tertiary.
    c) First, second and third.

12. What does the term “inflow test” mean?

    a) To apply pressure above a plug.
b) To apply pressure below a plug.
c) To bleed of pressure above a plug.
d) To equalise pressure across a plug.

13. How can a mechanical barrier stop the well-flow?
   a) By leading the flow down the kill-line.
   b) By applying a slight over-balance.
   c) By closing off the flow route.
   d) By closing Xmas tree valves.

14. If an inflow test cannot be performed, should the equipment be tested from above?
   a) Yes.
   b) No.

15. What item of equipment should be pressure tested before we rig up intervention equipment?
   a) Xmas tree
   b) Tubing hanger
   c) Packer
   d) Annulus.

16. When is a fluid-filled column regarded as a barrier?
   a) When the hydrostatic pressure is lower than the formation pressure.
   b) When the hydrostatic pressure is equal to the formation pressure.
   c) When the hydrostatic pressure is higher than the formation pressure.

17. A well is to be killed using packing fluid with a density of 1.08 kg/l. The measured depth is 3,173 m. and vertical depth is 3,171 m. Formation pressure is 332 bar. Which of the following statements is correct?
   a) There will be an over balance of 10 bar as compared with the formation.
b) There will be an over balance of 4 bar as compared with the formation.
c) The formation will be in balance.
d) There will be an under balance of 4 bar as compared with the formation.
e) There will be an under balance of 10 bar as compared with the formation.

18. What do we mean by the term “underbalance”?
   a) The hydrostatic pressure of the fluid is less than the formation pressure.
   b) The hydrostatic pressure of the fluid is equal to the formation pressure.
   c) The hydrostatic pressure of the fluid is greater than the formation pressure.

19. What do we mean by the term “overbalance”?
   a) The hydrostatic pressure of the fluid is less than the formation pressure.
   b) The hydrostatic pressure of the fluid is equal to the formation pressure.
   c) The hydrostatic pressure of the fluid is greater than the formation pressure.

20. A well is to be killed using packing fluid with density of 1.08 kg/l. The measured depth is 3,210 m and vertical depth is 2,821 m. Formation pressure is 310 bar. Which of the following statements is correct?
   a) There will be an over balance by 11 bar.
   b) There will be an over balance by 5 bar.
   c) The formation will be in balance.
   d) There will be an under balance by 5 bar.
   e) There will be an under balance by 11 bar.

21. Which of the following fluids are common fluid barriers? (Check three answers)
   a) Seawater.
   b) Diesel oil.
   c) Packing fluid.
   d) Nitrogen.
e) Condensate.
f) Drilling fluid.

22. How do we select a kill fluid?
   a) By calculating its acid content.
   b) By calculating its yield point.
   c) By calculating its viscosity.
   d) By calculating its hydrostatic pressure.

23. Can we combine mechanical and fluid barriers in the same well?
   a) Yes
   b) No.

24. When we open a valve that is pressurized on only one side, which of the following statements are correct? (Check two answers)
   a) The valve may suffer damage
   b) The valve may suffer a slight hydraulic shock
   c) We reduce the probability of pressure lock
   d) We may cause damage to equipment downstream of the valve
   e) We minimise the risk of damage to the valve.

25. When we shut down a well at the Xmas tree, which of the following statements are true? (Check three answers)
   a) The upper master valve will seal around the wireline.
   b) The lower master valve is normally not in use.
   c) The swab valve closes off all flow from the well.
   d) The valves may be damaged if they are closed against a wireline, tubing, etc.
e) The upper master valve is normally utilised.

26. Is it good practice to have more than one barrier always available?
   a) Yes.
   b) No.

27. Which of the following categories of barrier is a fluid barrier?
   a) Primary.
   b) Secondary.
   c) Tertiary.

28. A gas well has the following specifications:
    Total depth: 3,820 m. MD / 3,338 m. TVD
    Depth of production packer: 3,100 m. MD / 2,818 m. TVD
    Completion Fluid density: 1.08 kg/l (in Annulus)
    Gas gradient: 0.0226 bar/m.

    What is the pressure differential between the completion string and the underside of the tubing hanger in the annulus when the well is shut-in and the shut-in pressure is 127 bar?
    a) 108 bar higher in the annulus than in the completion string.
    b) 108 bar higher in the completion string than in the annulus.
    c) 127 bar higher in the annulus than in the completion string.
    d) 127 bar psi higher in the completion string than in the annulus.
    e) 235 bar higher in the annulus than in the completion string.
    f) 235 bar higher in the completion string than in the annulus.

29. What do we need in order to be able to select the correct kill fluid? (Check two answers)
    a) To have the possibility of pumping at a lower rate
    b) To minimize the formation over-pressure
    c) To have the possibility of maintaining a high pumping pressure
    d) To ensure correct fluid compatibility with the formation
To reduce losses in the annulus.

30. In the drawing below, identify the barrier elements (envelope) that:
   a. Maintain well pressure
   b. Prevent outflow from the annulus.

30a) (Check five answers)
   A. Xmas tree
   B. Tubing hanger/wellhead
   C. Annulars in wellhead
   D. Production string
   E. Completion fluid

A. Xmas tree
B. Tubing hanger/wellhead
C. Annulars in wellhead
D. Production string
E. Completion fluid
31. During a well operation a problem arises that requires the well to be killed. Which of the following is the most appropriate killing method if the perforation zone is open?

a) Volumetric.
b) Circulation.
c) Wait and weigh up.
d) Bullheading.
e) Concurrent.
f) Bleed off and lubricate

32. Well data:
Casing 9 5/8”, 53.5 lb/ft
Tubing 3 ½”
Production packer at 3,000 m. MD.

With the aid of the information in the table below, calculate the total volume of the annulus above the production packer. Write your answer in the box below.

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<th>OD(in/mm)</th>
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<td>9-5/8” / 244.5</td>
<td>8.407 / 213.5</td>
</tr>
</tbody>
</table>

Volume of annulus (m³)

33. In a planned kill operation, which killing method will probably be used?

a) Concurrent.
b) Reverse circulation.
c) Wait and weigh.
d) Circulation.

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34. Answer the following questions on the basis of the data given for a gas well:

Well depth   3,100 m. MD / 2,700 m. TVD
Formation gradient:  0.106 bar/m.
Gas gradient:   0.011 bar/m.

a) What is the bottom-hole pressure in bar?

b) What will be the maximum surface pressure in bar?

c) What is the correct working pressure for the wellhead/xmas tree?

1. 138 bar (2000 psi)
2. 207 bar (3000 psi)
3. 345 bar (5000 psi)

d) If the well is to be killed, what will be the minimum density of the kill fluid?

1. 1.08 kg/l
2. 1.26 kg/l
3. 1.14 kg/l

On the basis of the following additional data, answer the following questions:

Casing capacity:   41.26 l/m.
Tubing capacity:  13.51 l/m.
Tubing closed end displacement:  17.11 l/m.
Tubing depth:    2,790 m. MD / 2450 m. TVD

e) How many pump strokes are required to fill the tubing with killing fluid?

1. 1946 strokes
2. 2514 strokes
3. 2654 strokes
f) How many pump strokes are needed to fill the whole well?

1. 7009 strokes
2. 8235 strokes
3. 6290 strokes

35. In an emergency situation in which it is impossible to bullhead, what will be the most suitable killing method?

a) Volumetric
b) Circulation
c) Wait and weigh up
d) Bleed off and lubricate
e) Concurrent

36. What are the advantages of utilizing reverse circulation? (Check four answers)

a) The surface pressure is kept low.
b) There is less danger of formation damage.
c) It is a slow process.
d) We have to utilise wireline.
e) Dirt can plug up the formation.
f) The production tubing and annulus end up with pure killing fluid.
g) All wells can normally be killed using this method.

37. Which of the following determine whether it is possible to bullhead? (Check two answers)

a) Working pressure rating of the surface equipment.
b) The completion string collapse pressure.
c) The position of the blind ram
d) The permeability of the formation
e) The type of workover string in use
38. In which of the following wells will bull heading be preferable to bleeding down and lubricating? (Check two answers)

a) A well that has stopped producing gas due to internal sand and scale.
b) A well in which a plug is stuck in the tailpipe.
c) A well in which the sliding sleeve is stuck in closed position.
d) A well with a serious leak in the control line to the DHSV.
e) A well whose casing has collapsed just above the perforations.

39. In which of the following situations would bull heading be a likely kill method? (Check three answers)

a) A well with a failed DHSV that can not be pulled.
b) When speed is important.
c) When insufficient information is available to calculate a reverse-circulation kill.
d) When there is a risk of formation damage.
e) In a well with a plug stuck in the tailpipe.

40. Given the following data for a gas well, answer the questions below:

Well depth: 3,100. MD / 2710 m. TVD
Formation gradient: 0.112 bar/m.
Gas gradient: 0.010 bar/m.

a) What is the bottom-hole pressure in bar?

b) What will be the maximum surface pressure in bar?

c) What is the correct working pressure for the wellhead/xmas tree?

2. 207 bar (3000 psi).
3. 345 bar (5000 psi).

d) What sort of kill density (kg/l) is needed to kill the well?

1. 1.03 kg/l
2. 1.08 kg/l
3. 1.14 kg/l
On the basis of the following additional data, answer the following questions:

- Casing capacity: 41.26 l/m.
- Tubing capacity: 6.94 l/m.
- Tubing closed end capacity: 11.53 l/m.
- Tubing depth: 2,850 m. MD / 2,490 m. TVD
- Pumping capacity: 19.19 l/stroke.

**e)** How many pump strokes are required to displace the completion string?

1. 980 strokes
2. 1030 strokes
3. 1234 strokes

**f)** How many strokes are needed to displace the whole well?

1. 4289 strokes
2. 4587 strokes
3. 5446 strokes

41. Which of the following statements regarding bull heading are correct? (Check two answers)

a) It can only be carried out if the perforations are open
b) It can be carried out before the intervention begins when there is a two-way check valve in the tubing hanger
c) It may plug the formation
d) It is normally done instead of the alternative of opening the sliding sleeve
e) The method is more difficult than bleeding off and lubricating.

42. Given the following data:

- Depth of tubing: 2,670 m. MD / 2,480 m. TVD
- Tubing capacity: 12.10 l/m.
- Annulus capacity: 21.59 l/m.
Pumping rate: 795 l/min (Forward Circulation)

a) Calculate the minutes required to pump up the well
b) Calculate the minutes required for full circulation.

43. Which of the following best describes the killing method of bleeding down and lubricating?

a) It is carried out by bleeding down the well pressure to zero and circulating in kill fluid.
b) It is carried out by bleeding down the well pressure to zero and topping up the tubing with kill fluid.
c) It is carried out by pumping in one tubing volume of kill fluid and then bleeding down the well pressure to zero.
d) It is carried out by repeatedly pumping in a small volume of kill fluid and then bleeding down back to the same pressure as we had before starting pumping.

44. Given the following data:
Depth of tubing: 3000 m. MD / 2,600 m. TVD
Tubing capacity: 18.31 l/m.
Annulus capacity: 11.32 l/m
Pumping rate: 795 l/min (Forward Circulation)

a) Calculate the minutes required to pump up the well
b) Calculate the minutes required for full circulation.

45. The following graph illustrates changes in pressure when we use the reverse circulation method. The ID and OD of the casing and completion string are constant. The kill fluid being pumped is lighter than the completion fluid in the annulus.
Answer the following questions:

a) What is the total volume (liters) of the well?  

b) What is the well pressure (bar) at start of kill?  

c) What is the well pressure after 1800 liters have been pumped?  

d) What is the annulus pressure after 1800 liters have been pumped?  

e) At what point does the kill fluid fill the annulus while the original completion fluid fills the completion string? A, B, C, D, E or F.  

46. Which of the following statements are true? (Check two answers)

a) Losses always occur in the lowest zone of the formation.  

b) Losses always occur in the uppermost formation zone.
c) Losses can occur in any formation zone.
d) Losses can occur in one zone while another zone is producing.
e) Pumping a heavy liquid will cure the losses.

47. Which of the following measures can prevent or remove hydrates?
   (Check three answers)
   a) Rapid bleed-off of gas from the topside system.
   b) Use of water/glycol mixture during pressure testing.
   c) Pressure testing up to close-in pressure.
   d) Raising the temperature of the equipment used.
   e) Injecting methanol into the equipment.

48. Who shuts in the well and is responsible for safe working if a problem occurs during an intervention operation?
   a) The operator’s representative (well foreman).
   b) The well service manager.
   c) The production manager.
   d) The leader of the intervention team.
   e) The operator of the intervention equipment.

49. Answer the following questions by “True” or “False”
   a) The temperature must be below 0 °C for hydrates to form.
   b) Hydrates only form in the presence of free water.
   c) Hydrates are less likely to form if glycol is injected.
   d) Hydrates will melt at the same pressure as they form.
   e) Hydrates are normal downstream of choke valves.
   f) Hydrates form more readily at low than at high pressure
   g) Hydrates can cause damage if they come loose.

50. Which of the following measures can help to remove hydrates?
    (Check three answers)
    a) Pull out of the well and fill the topside equipment with diesel oil.
b) Check for the presence of external ice in order to locate the hydrates.

c) Close the lowest BOP, bleed down the pressure above it, open the connection above the BOP and remove the hydrates.

d) Inject methanol.

e) Try to warm up the hydrates using a high-pressure steamer.

f) Work the string up and down while you bleed off the surface pressure.

51. Which of the following statements are applicable to tasks that are performed well and safely? (Check three answers)

a) Always use Xmas tree as the primary barrier.

b) Hold a pre-job safety meeting with all personnel involved.

c) Always warn the foreman before shutting in the well.

d) Make sure that the foreman is always in position near the well.

e) Make sure that all personnel know what to do if a problem should arise.

f) Only use tested, inspected and well-maintained equipment.

52. If a well-control incident occurs, which of the following actions are correct?

a) The well-team, well foreman (operator’s representative) and foreman hold a meeting when the incident has occurred, at which they discuss the best way of getting the well back under control.

b) The well-team, well foreman (operators representative) and foreman hold a pre-job meeting to allocate roles and responsibilities for the shut-in and for controlling the well if an incident should occur.

c) The well-team, well foreman (operator’s representative) and foreman hold a meeting with the onshore organisation after the incident has occurred in order to get instructions regarding how the shore organisation wishes the situation to be dealt with.

d) The well-team, well foreman (operator’s representative) and foreman hold a meeting with the well-fluid operator when the incident has occurred, at which they seek his advice regarding the best kill method.

53. Which of the following statements best describes a good kick-off meeting?

a) Get everyone involved to attend the meeting and explain exactly what is going to happen during the operation.

b) Get everyone involved to attend the meeting and go through plans, ask for feedback and comments, modify the plan if necessary and make sure that everyone understands in properly.
c) Get everyone involved to attend the meeting and read out the plan sent out by the onshore organization. Explain that the plan must be followed exactly.

54. A problem has occurred with a well and it has been shut in. What do you do now?
   a) Delegate the problem to the well manager (operator’s representative) and wait for the end of your shift.
   b) Read the instructions in the well program, ring the onshore organization and ask for advice.
   c) Monitor the well while the personnel are being evacuated.
   d) Involve the local contingency organisation and request them to remain on stand-by.
   e) Hold a meeting with all parties involved and draw up a plan. Ask the onshore organisation for its comments.

55. Which of the following mechanical barriers can be installed by a well intervention operation? (TWO ANSWERS)
   a) Float valve.
   b) Differential valve.
   c) Dump valve.
   d) Wireline plug.
   e) Pump through plug

56. How is a plug used to shut off flow?
   a) Installation across the flow path, sealing off the tubing or casing.
   b) By creating an overbalance of 100 psi, to stop the flow.
   c) By sealing off the perforation zone.
   d) By installing a tubing hangar.
   e) By keeping the pressure below the Xmas tree valves.

57. How does a mechanical barrier prevent flow?
   a) By closing off the well path.
   b) By closing the Xmas tree.
   c) By pumping the flow through the kill line.
d) By applying a small overbalance pressure.

58. A live production well is to be killed by bullheading before starting a well intervention operation. Which of the following pressures can limit the maximum allowable surface pressure? (THREE ANSWERS)

a) The existing SIWHP.
b) The burst limit of tubing.
c) The downhole safety valve operating pressure.
d) The ID of the tubing string.
e) The maximum pump speed.
f) The working pressure of surface equipment.
g) The possible fracture of the formation.

59. While performing a well intervention operation, different types of barriers may be used to control well pressure. What is the common name for each type of barrier?

a) 1st, 2nd and 3rd generation.
b) First line, second line and third line.
c) Mechanical and fluid.
d) Primary, secondary and tertiary.
e) 1st class, 2nd class and 3rd class.

60. Bottom hole pressure 262 bar (3800 psi), maximum surface pressure (210 bar) 3050 psi. Select the correct rated working pressure of the equipment to be used on the wellhead.

a) 207 bar (3,000 psi).
b) 345 bar (5,000 psi).
c) 138 bar (2,000 psi).

61. Which statements are true in regards to Xmas tree valves during a well intervention operation? (THREE ANSWERS)

a) The lower master gate valve is not normally used.
b) The upper master gate valve will seal around wire line.
c) Valves can be damaged if they are closed on a tool string.
d) The upper master valve is normally used if there is nothing in the well.
62. A flowing production well is being shut in at the Xmas tree, the SITHP quickly builds up to 138 bar (2,000 psi), during the next three hours the SITHP slowly climbs up to 162 bar (2,350 psi). What is the most likely to cause this increase in SITHP?

a) Gas cap effect.
b) It is normal, all wells seem to be like that.
c) Perforation zone was plugged off.
d) DHSV was stuck in the closed position.

63. What kind of barrier (barrier terminology) is a Shear/seal BOP (safety head) when used immediately above the well head?

a) Tertiary.
b) Primary.
c) Secondary.

64. Which of the following kill methods is time consuming, compared to other methods and recognized only in the terminology of well intervention operations?

a) Volumetric.
b) Bull heading.
c) Forward circulation.
d) Wait and weight method.
e) Concurrent method.
f) Bleed off and lubricate.

65. If it is not possible to perform an inflow test on the installed plug, should the plug be pressure tested (integrity test)?

a) Yes
b) No

66. Injecting brine into the flow stream can reduce the formation of hydrates?
67. In an emergency situation, if it is not possible to bullhead the well, which method is the most suitable to kill the well?
   a) Volumetric.
   b) Concurrent method.
   c) Wait and weight method.
   d) Bleed off and lubricate.
   e) Bull heading.
   f) Forward circulation.
   g) Reverse circulation.

68. Which of the following are “closable” barriers? (TWO ANSWERS)
   a) Tubing hangar plug.
   b) Packer.
   c) BOPs.
   d) Pump out plug.
   e) DHSV.
   f) Check valve.
   g) Master gate valve.

69. Hydrates are most likely to form downstream of the chokes?
   a) Yes.
   b) No.

70. Can a Dead well be inflow tested?
   a) Yes.
   b) No.
71. When the hydrostatic pressure of a fluid in a well overbalances the formation pressure, it becomes a primary barrier?
   a) True.
   b) False.

72. Which of the following conditions for the formation of hydrates is correct
   a) High temperature and low pressure.
   b) Low temperature and low pressure.
   c) High temperature and high pressure.
   d) Low temperature and high pressure.

73. Which of the following statements are correct, if opening a closed valve that is highly pressured on one side? (two answers)
   a) It can cause damage to the valve.
   b) It will reduce the risk of damage to the valve.
   c) It will reduce the chance of pressure locking the valve.
   d) It will cause less hydraulic shock to the system.
   e) It can cause damage to equipment downstream of the valve.
   f) It can cause damage to equipment upstream of the valve.

74. What is the primary advantage of a wireline retrievable downhole safety valve?
   a) Simple construction.
   b) Can be retrieved and replaced.
   c) Can be installed after running in the tubing.
   d) Can be removed to allow through tubing intervention work.
Principles & Procedures Quiz: Answer Key

1. b
2. c
3. a
4. c
5. e
6. c & d
7. a, b, e, f, k & l
8. c
9. a, c & e
10. d
11. b
12. c
13. c
14. a
15. a
16. c
17. b
18. a
19. c
20. e
21. a, c & f
22. d
23. a
24. a & d
25. b, d & e
26. a
27. a
28. d
29. b, d
30 a). A, B, D, G, H
31. d
32. 92.1 m³
33. b
34. a) 286 bar
34. b) 257 bar
34. c) 345 bar
34. d) 1.08 kg/l
34. e) 2514 strokes
34. f) 7009 strokes
35. d
36. a, b, f & g
37. a, d
38. c & d
39. a, b & c
40. a) 304 bar
40. b) 276 bar
40. c) 345 bar
40. d) 1.14 kg/l
40. e) 1030 strokes
40. f) 5446 strokes
41. a & c
42. a) 72.51 min
42. b) 113.15 min
43. d
44. a) 42.7 min
44. b) 111.8 min
45. a) 10800 liters
45. b) 160 bar
45. c) 60 bar
45. d) 0 bar
45. e) E
46. c & d
47. b, d & e
48. e
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CHAPTER

2

COMPLETION
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1. GENERAL

1.1 Monobore completion

Completion is the general name for the equipment that is placed in the well after the drilling phase in order to enable the well to be brought into use as a producer or injector well. Completion equipment comprises the completion string with its individual components, and the Xmas tree at the top of the well.

The term “monobore completion” refers to a completion string that has approximately the same internal diameter throughout the well and the Xmas tree. The monobore concept was introduced around 1990, with the introduction of new drilling technology that allowed longer, more horizontal wells to be drilled. Monobore meant the elimination of all previous restrictions on which cable tools and coiled tubing were liable to catch (entry profiles, nipple profiles, changes in cross-section).

A special detail is the change in cross-section between the liner (the lowest casing of the well) and the completion string. To deal with this problem, a “plug and socket” solution was developed, whereby the lowest part of the completion string - the sealstem (male part) enters a Polished Bore Receptacle (PBR) (female part) located at the top of the liner, producing a virtually smooth transition without restrictions.

With monobore completions, the well is virtually free of nipple profiles (normally such a profile is found in the tubing hanger and one or two metres above the down-hole safety valve). If components are to be placed temporarily or semi-permanently in the well, equipment with slips (and packing elements if the equipment is to be pressure-tight) must be used.
Figure 1
1.2 Bottleneck completion

Wells with a large-diameter liner and a small-diameter completion string are described as having bottleneck completions. Such completions were normal 10 or 15 years ago. The problem with wells of this sort was that of locating plugs in the liner zone (e.g. for zone isolation) - which required mechanisms that “grow” when they are set. This type of equipment is permanent and cannot be pulled once it has been set.

An example of a bottleneck completion would be a well with a 7” liner in which the completion string has a diameter of 5½ “.
A Typical Completion

Figure 2
2. PRODUCTION PACKER

2.1 Functions

The production packer is located fairly deep in the well in order to isolate the annulus from the well fluids. The production packer acts as a barrier, and there must be no leakages of hydrocarbons/pressure past the packer.

When the production packer is set, the completion string is locked to the casing on the outside (e.g. 9 5/8”). This connection is normally tested both from above (by pressure testing the annulus) and below (down the completion string to the liner).

In order to be certain that the connection does not weaken in the course of time, there is a requirement that cement should be placed behind the casing at the site of the production packer (as we can imagine, if the casing were to corrode below the packer, there would be a leakage of hydrocarbons through the casing to an annulus with a lower pressure classification, which would be fatal).

The tubing from the production packer down to the seal stem or the entry guide sleeve is called the tailpipe. During re-completion, when the completion string is being pulled, a plug is place in this tailpipe, so that the plug and tailpipe plus the production packer make up one barrier (the other is the BOP).

2.2 Types of packer

Production packers are described as either permanent or retrievable. Permanent packers are the most common - but have to be milled away if they need to be removed. Retrievable packers can be difficult to retrieve if they have been in position for a long time. If the pressure and temperature have changed a great deal during the operating phase, this may also loosen the packer (the weight required to lock the packer will have been removed).

Retrievable packers

When a retrievable packer is set it is rotated, then weighted, either by stretch or compression, depending on the design. A J-slot mechanism is normally employed. In the driving-in phase, the pin is held in the short part of the J-arm and this prevents the inner part of the packer from moving and setting the slips. When the pin has been rotated to the long part of the J-arm, the inner part of the packer can be moved enough to allow the packer to be set.
Retrievable packers are equipped with a set of slips, in which the packer element or sealing element is located either over or under the slips. During setting, the seal element is squeezed against the casing and the weight continued to be applied to it to keep the slips and sealing element in contact with the casing.

To retrieve the packer, the added weight is removed and the packer/completion string will be loosened.
Figure 3
Permanent packers

Packers of this sort are normally run as part of the completion string, but they can also be run as part of the tailpipe when the completion string is installed in two phases. They are normally set hydraulically, but mechanical methods also exist, as well as methods based on explosives (as for bridge plugs).

Such packers have a double set of slips, each of which works in a different direction. The packing element is situated between the slips. The packer may be of double cylinder design, so that both slips move in the direction of the packing element and squeeze it against the casing wall, or singly cylindrical, in which case one slip moves towards the other and squeezes the packing element simultaneously.

If we wish to remove the production packer, we must first remove the completion string as far down as the production packer (the connection between the production packer and the completion string may consist of coarse ratch-slash screw threads. The connection can also be mechanically cut. In order to loosen the production packer, we need to mill out the upper slips segment, and in some cases the packing element as well (which may take 2 - 12 hours).

The mill-out extension lies immediately under the production packer. This is a circular tube with a slightly larger internal diameter than the ID of the production packer. When milling out is to take place, a “packer picker” is installed inside the mill-out extension. When the packer has come loose the packer picker will hold on to the remaining parts of the packer and tailpipe, which can then be retrieved by the milling assembly.
3. EXPANSION JOINT

3.1 Functions

The purpose of the expansion joint is to minimise the load on the production packer and completion string resulting from changes in down-hole pressure and temperature. The expansion joint will adopt different positions according to current temperature and pressure conditions in the well.

It can be pointed out here that there exist a number of field solutions that have eliminated expansion pipes because of the risks of leakage over long periods of time. These require the adoption of special design measures.

3.2 Types of expansion joint

A number of technical solutions exist, some of which are linked to the production packer itself, other as independent arrangements.

Two solutions exist in principle:

a) The packer rings sits inside the pipe receptacle (female part). This pipe receptacle can stand on to the production packer or in an assembly installed one or two pipe-lengths above the production packer. In such cases, the male part is located at the bottom of the “upper” part of the completion string.

b) A sealstem can be used, where the packer rings sit on the outside of the pipe (male part). In this case, the counterpart of the sealstem is in the Polished Bore Receptacle (PBR) which forms part of the production packer or in an independent assembly one or two pipe-lengths above the production packer.

In high-temperature applications the packers must be of a special type (Aflas).

When it is being run into the well, the two parts of the expansion pipe are pinned together. These pins often break when the completion string is being pressure tested after the production packer has been set.

When the well is being re-completed the completion string is parted in this joint and half the joint is followed to surface. When a new upper completion string is being run, the old part of the expansion joint at the bottom of the new string is utilised.

If the expansion joint is of the “independent” type, it is connected to the production packer by means of an anchor (tubing anchor). This is a ratch-slatch mechanism which
locks the upper part of the completion string to the production packer by setting down a weight. To release the completion string in the same joint, one maintain a weight of 2 - 3 tonnes over and above the neutral weight and rotating it to the right.

The extent to which the two parts of an expansion joint will move relative to each other depends of course on the physical conditions to which the well is exposed. VAG wells in the North Sea are exposed to fairly extreme pressure and temperature variations. During gas injection the pressure may be as high as 400 - 450 bar and the temperature 100 - 120 °C. Within a short time the pressure may be 250 bar and the temperature 10 - 15 °C. In a typical North Sea well the expansion pipe will move by about 3 m between these two phases.

The transition between the liner and the lower part of the completion string was mentioned at the beginning of this chapter. Here, a PBR is used at the top of the liner and a sealstem at the bottom of the completion string. In order to avoid the sealstem from bottoming out in the PBR when the completion string is being spaced out, a stop ring is placed on top of the PBR; this is known as the Fluted centralizer. This has a centering function, but is also designed to permit circulation to take place; hence the designation “fluted”. During spacing out, normal practice is to pump carefully down through the completion string; when we see that the pressure is rising (the pump stops) we know that the lowermost packer on the sealstem has entered the PBR and that there are still perhaps 2.6 metres to go before the stop ring meets the top of the PBR.
4. CIRCULATION EQUIPMENT

4.1 General

The term “circulation equipment” refers to the following items:

- Side Pocket Mandrels (SPM)
- Sliding sleeves
- Nipples with port(s)/sleeves

Circulation equipment is employed to:

- Provide gas-lift (SPM with gas-lift valves (GLVs)/nozzle)
- Create an under-balance in the well in advance of perforation (SPM, sliding sleeve and nipple)
- Kill the well (SPM, sliding sleeve and nipple).

With the exception of gas-lift SPMs, circulation equipment is very seldom used in our sector of the North Sea.

Sliding sleeves and nipples with movable sleeves have a doubtful reputation. Such equipment may well be tight before it is used, and can be opened for circulation, but is seldom tight following circulation.

Our sector of the North Sea usually employs SPMs, which are useful because various types of equipment can be placed in the pocket: plugs, gas-lift valves, nozzles/non-return valves.

4.2 Side Pocket Mandrels

SPMs are used either for gas-lift purposes or for temporary communication between the annulus and the completion string (to create an under-balance in the well, to kill the well, etc.).
Figure 5
The SPM is located to the side of the well flow. A special type of cable tool known as a “Kickover Tool” (KOT) is utilised when plugs or valves in the SPM have to be replaced. The maximum well angle at which the KOT can be used is around 50 - 60 degrees, and the greater the angle, the more complicated it is to operate the KOT.

An important point to remember before plugs or valves in the SPM can be pulled is to equalise the pressure across the GLV. This may be difficult when there are hydrocarbons in the completion string, and it will sometimes be necessary to force these out of the well with seawater or to set a deep-set plug before this operation can commence.
Kick Over Tool
Running Procedure

A) The Kickover Tool is lowered into the tubing until it is below the selected mandrel.

B) Raising the toolstring orientates the kickover tool over the pocket. Lowering the toolstring causes the device to enter the pocket.

C) The device is located in the pocket and jarring separates the device from the running tool.

D) The toolstring can be withdrawn from the well.
Equipment that can be located in side pockets:

Shear out valve (communication – one way - through the valve is achieved by shearing a disk in the valve by absolute pressure)
Circulation or orifice valve
Injection valve (with single or double non-return function)
Pressure and temperature sensors
Plug (dummy valve)
Gas-lift valve (nitrogen pressure-controlled).

4.3 Sliding sleeves

A sliding sleeve can be installed in the completion string. In the North Sea, sliding sleeves are primarily employed in the reservoir zone (in the liner part of the well) if we wish to produce the reservoirs individually. In such cases, the individual reservoirs are separated by means of zone-isolation packers (often filled with cement) which prevent communication by any other means than via the sliding sleeves within the well.

Both in theory and in the real world, sliding sleeves can also be used for gas-lift purposes. When the pressure in the well is too low for production - or when the liquid column has become too heavy because of high water cut, we can open the sliding sleeve and inject gas into the well via the annulus or lighten the liquid column and increase production.

A sliding sleeve consists of a movable inner sleeve with slit ports and a fixed outer part which is installed as part of the liner or completion string. We can move the inner sleeve up and down with the aid of a shifting tool which is run on a wireline or coiled tubing.
Figure 7
4.4 Nipple with port/sleeve

This is a nipple that has ports between the inside and the outside. When the port that provides access to the annulus is not to be used, a sleeve with packers in the nipple profile is installed. Equipment of this sort is seldom utilised.
5. DOWN HOLE SAFETY VALVES

5.1 General

Downhole safety valves (DHSVs) are installed in the well in order to prevent blowouts if:

- the topside Xmas tree becomes damaged (e.g. by collision with a crane lift)
- surface equipment is sabotaged
- a neighbouring well suffers a blow-out (in order to prevent a domino effect)
- drilling collision from neighboring well (the valve must be located so deep that drilling-in will most probably be above the valve).

Such valves are of the “Fail-safe Closed” type. If hydraulic pressure to the valve is lost, it will immediately close.

These valves can also be pumped through from the surface even when they are closed.

Such valves exist in two versions:

- Flapper valves
- Ball-valves.

Flapper valves open in a “down-well” direction, while ball valves rotate so that the valve opening matches the direction of the well flow.

The Norwegian Petroleum Directorate (NPD) requires downhole safety valves to be installed at least 50 m below the seabed. There are no specific international requirements as to location, i.e. the operator determines the minimum installation depth. In the North Sea, normal practice is to locate the valve sufficiently deep that hydrates will not interfere with valve operation.

Internationally, the DHSV is not regarded as a well control barrier. This is because the API permits a certain amount of leakage through the DHSV: 0.4 l/min liquid or 25.5 Sm³/hour gas. Some countries regard the DHSV as a barrier after an approved inflow test which verifies that the above-mentioned leakage rates are not exceeded.

Some DHSVs can be installed by wireline in a downhole nipple profile, while others are integrated into the completion string. Each version may be of either the flapper or ball-valve type.
5.2 Wireline retrievable DHSVs

Safety valves of this type are installed in a nipple profile in the completion string. The nipple profile is connected to the surface via a hydraulic control line. When the DHSV is retrieved there will therefore be an open connection to the surface via this control line. If the DHSV is going to be out of the well for any length of time, a protective sleeve will normally be installed in the profile.

Wireline-retrievable DHSVs often produce a restriction in the well which may result in local erosion as well as choking the well-flow. If intervention in the well is required below the location of the DHSV, this must be retrieved ahead of the intervention.

If a problem with a DHSV arises, it is a simple matter to retrieve it and install a new one.
5.3 Tubing-installed DHSVs

This type of DHSV is installed as an integral part of the completion string. In the case of problems with such valves the whole completion string must be pulled. Some valves in use also have a nipple profile for a wireline-retrievable DHSV as a back-up solution in case problems should occur. Certain operators also use two integral valves in the same string, so that they always have one valve in reserve.

If a reserve valve is installed the main valve is kept permanently locked open and a special type of wireline tool is utilised.

The advantage of this type of DHSV is its large internal diameter and the lack of a control line which can allow a flow of well fluids to reach the surface. On the other hand, it is important that the valve should remain open throughout a well intervention. During well intervention it is usual to have a dedicated guard who keeps a continuous watch on the valve.

In the case of a heavy well intervention, e.g. involving coiled tubing or snubbing, it is normal to install a protective sleeve in the valve in order to protect it from damage.

Some DHSVs are fitted with an integrated pressure-equalization mechanism. When hydraulic opening pressure is applied to the valve, a small port through the valve is opened and remains open until the pressure on both sides of the valve has equalized, before the valve itself is opened. The point of this mechanism is to minimize damage to the valve.

The hydraulic pressure required to open a DHSV is the opening pressure (when the valve is lying on deck, e.g. 200 bar) plus the well maximum shut-in pressure (e.g. 345 bar).
Figure 10

Tubing Retrievable Safety Valve
5.4 Annulus safety valve

Some countries require annulus safety valves to be installed in gas-lift wells on fixed installations. The idea is the same as for DHSVs, i.e. to prevent an uncontrolled reverse backflow of gas from the annulus, if any of the wellhead and/or Xmas tree equipment should be damaged.

Flapper or plug valves are normally used in annulus safety valves (fail-safe closed type).
6. NIPPLE PROFILES

6.1 Functions

Nipple profiles or anchoring profiles are installed as part(s) of the completion string. These profiles are used to install equipment down-hole, either temporarily or for long periods of time:

- Plugs (to seal/isolate the completion string at this location)
- Valves
- Monitoring equipment (temperature and pressure).

The nipple profile consists of a locating profile, a no go shoulder and a sealing surface. The no go shoulder prevents the equipment that is being installed from going any further down the well, at the same time as it ensures that the locking dogs on the plug or valve grip the correct part of the profile. The no go shoulder may be located either above or below the locking profile.

In a well that contains several nipple profiles, the internal diameter of the profiles will gradually decrease the further down the completion string they are. Typical nipple profile locations include:

- Tubing hanger (also in monobore wells)
- Above the DHSV (also in monobore wells)
- Above the expansion joint/circulation equipment (e.g. side-pocket, sliding sleeve - in order to test the completion string above such equipment)
- Below the production packer (in order to set the production packer)
- At the bottom of the completion string (in order to monitor temperature and pressure).

When equipment is to be retrieved it is extremely important to equalize the pressure before retrieval, at least as far as possible. Some plugs are fitted with prongs which can be pulled to open a port through the plug and equalize the pressure. When the pressure has been equalized the locking dogs holding the nipple profile are released by means of the retrieval tool.

A problem with nipple profiles is that they are liable to fill up with deposits when the well is being produced. If this happens the profile must be brushed clean or treated with chemicals before it is used.
Figure 11

Bottom No-Go Nipple and Wireline Lock

- Locking Recess
- Packing Bore
- No-Go
- Locking Dogs
- Chevron Packing
7. TUBING HANGER

7.1 Functions

The tubing hanger fulfils several different tasks in the completion string:

- It transfers the weight of the completion string to the wellhead
- It seals the top of the production annulus (this is a barrier function, i.e. it prevents pressure in the annulus from leaking past the tubing hanger to the Xmas tree or out to the atmosphere or the sea, or vice-versa)
- It allows an internal plug to be installed - by means of either a nipple profile or screw connection (plugs are utilised in the installation and retrieval of Xmas trees)
- It provides a seal around hydraulic and electrical control lines which have been “drawn” through the tubing hanger.

Figure 12

Tubing Hanger
7.2 Subsea tubing hanger

Tubing hangers for subsea use have the same range of functions as surface-installed tubing hangers. Subsea tubing hangers must also be properly oriented and locked when they are landed. Correct orientation is important because all hydraulic and electrical functions are connected up to the Xmas tree by an ROV. The tubing hanger is locked to the wellhead or Xmas tree by remote control from the surface.

7.3 Plugs for location in tubing hanger

The following types of plug are utilised:

- Back Pressure Valve (BPV)
- Tubing Hanger Plug (THP)
- Two-way Check Valve (TWCV).

The BPV maintains pressure from below, but allows pumping through the plug from above (pumping pressure must be higher than the pressure below the plug). This plug can be wireline installed or manually installed (by sluicing it through the topside Xmas tree with the aid of a lubricator).
The TWCV provides a seal in both directions as long as there is a high pressure differential across the plug, at the same time as it permits slow pumping through the plug from above. The TWCV can be installed either by wireline or manually.

Plugs can also be screwed into position in tubing hangers with a screw profile. Plugs of this sort are installed manually with the aid of the lubricator that controls the well pressure during installation/retrieval.

Figure 14
8. WELLHEADS

8.1 Functions

The wellhead provides the following functions:

- Anchoring/connections for each individual casing
- Pressure isolation of individual casings
- Connections for Xmas tree
- Connections for completion string
- Isolation of production annulus
- Access to annulus for pressure monitoring and/or pumping.

In some wells, the annulus (e.g. 20” x 13 3/8”) is used for slop injection in parallel with the well’s primary function as a producer or injector.

Two types of wellhead are in use:

- Compact wellheads, as used on subsea installations
- Conventional wellheads, which are made up of modules for each section plus casings.

8.2 Compact wellheads

A subsea well is started by drilling a hole for the conductor (32”, 30” or 28”) down through the upper soft layers of the seabed - normally 50 to 150 below the seabed. The conductor is then suspended from the seabed, for example in a 30” wellhead housing. The conductor is cemented right up to seabed level.

Drilling continues (without BOP) (e.g. 26” hole) down to the pressure build-up zone and a 20” casing is suspended from a compact wellhead (e.g. 18 ¾” wellhead housing). This casing is also cemented up to seabed level.

A subsea BOP is then installed and all the remaining sections are drilled, set with casings and cemented without the need to bring the BOP up to the surface. Each casing section is locked to the same wellhead using dedicated locking rings (seal assemblies) and the weight is also transferred to the same wellhead.
Compact Wellhead

Figure 15
8.3 Conventional wellhead

Fixed platforms also utilise conductors for which holes are either drilled or pile-driven.

As new sections continue to be drilled, and casings are installed and cemented, the wellhead is built up of modules, each of which consists of a different section/casing dimension. When a new module is installed the BOP must be removed from the previous module and set aside until the new module is in place. The BOP is then re-installed and drilling of the next section can commence.

Annulus valves are mounted on each module in order to monitor annulus pressure. The completion string is suspended from the uppermost module. The tubing hanger is locked to this module by means of a locking ring and a barrier seal is produced by means of sealing rings between the tubing hanger and the module. After the completion string has been landed, wirelines passed through the tubing hanger are passed through tracks or holes in the module to the outside, where the wirelines are terminated.
Conventional Wellhead

Figure 16
9. XMAS TREE

9.1 General

The Xmas tree is an item of safety equipment that is placed on top of the wellhead. It consists of a system of valves which may be either open or closed according to the state of the well (ordinary operation, well-tool intervention, pumping, testing, repairs).

The purpose of the Xmas tree is to control the flow of hydrocarbons from the well and to allow access to the well during the operational phase. We call the Xmas tree a safety barrier.
CONVENTIONAL XMAS TREE

Figure 17
The following valves are normally installed on the Xmas tree:

- Manual operated master valve
- Hydraulic operated master valve
- Hydraulic operated wing valve
- Manual operated Swab valve
- Manual operated Kill valve.

Manual operated master valve
This is located closest to the wellhead and is the back up valve for the Hydraulic master valve.

Hydraulic operated master valve
This is located above the Manual master valve. It is hydraulically actuated (from the platform control room) and is “fail-safe closed”. In the case of a hydraulic leak, the valve will revert to its closed condition.

Hydraulic operated wing valve
This is the “last” valve in the Xmas tree before the well-flow enters the flow line to the choke valve/process system. This valve is normally “fail-safe closed”.

Swab valve
This is a manual valve that stands at the top of the Xmas tree under the “tree cap” (also known as the “lubricator adaptor”). This valve must be opened in the case of well intervention (by wireline, coiled tubing or snubbing). On the outside of the swab valve we often find a socket or cup that acts as “barrier element no. 2” if the valve leaks. It is important that this cup should be fitted with a “check valve” so that any pressure on the other side can be checked using a pressure gauge and bled off trapped pressure before the swab valve is opened.

Kill valve
This valve is located next to the wing valve and is used during pumping (scale squeeze injection, washing, killing, bleeding) and production or injection via neighbouring wells. This valve is normally also fitted with a cup and “check valve”.

9.2 Valves

Two types of valve are in use:

- Split gate
- Slab gate.

The split gate valve is equipped with paired gates with springs between them that tension the gates against the valve seats. Only one of the gates forms a seal when there is a pressure differential across the valve, i.e. the pressure differential counterbalances the tensioning power of the one gate, but adds to that of the other.
Split gate valves may suffer from a phenomenon known as “double block”, whereby locked-in pressure between the gates makes it impossible to open the valve. The swab valve is particularly liable to this condition when rigging up on the Xmas tree (e.g. wireline, coiled tubing or pressure tubing) is being tested against this valve. The problem can be solved by bleeding off the pressure via the valve’s test port.

Slab gate valves have only one gate.

Valves can leak in the direction of flow, but also via the valve body/stem. In normal valve design an extra metal-to-metal seal is incorporated between the valve body and the stem. If the valve leaks via the valve body/actuator side such leaks can be stopped by screwing the valve to the “backseat” position.

Some valves are designed in such a way that in the case of fire the valve will automatically put itself into backseat position (e.g. lower master valve, upper master valve and swab valve).

Hydraulically actuated master valves often incorporate a functional requirement that they should be able to cut wirelines. In such cases it is important to know the type and dimension of the wireline on which the valve has been tested. A hydraulically actuated master valve that can be used as a “shear/seal” valve improves safety during wireline operations.

It is normally impossible to cut wirelines with manually operated valves. The torque required would be so high that parts of the valve would be destroyed before the wireline was cut.

Flanged components with R and RX sealing rings will “set” and will need to be post-tightened during the operational phase (as these rings are not connected “face to face”). This does not happen to the same extent with BX rings.

9.3 Types of Xmas tree

Most field operators have their own philosophy regarding the way that Xmas trees are built up. For example, some operators have chosen to eliminate the manual master valve and the kill valve.

We can distinguish between the following types of Xmas tree:
- Solid block/split block Xmas tree
- Horizontal Xmas tree
- Dual Xmas tree
- Subsea Xmas tree.
Solid block/split block Xmas tree

In split block Xmas trees the master valves (manual and hydraulic) are located together in a separate “lower” block. The lower block is joined to the upper block via an API flange or clamped coupling. Split block trees are simpler and cheaper to maintain.

Solid block (monoblock) Xmas trees contain fewer components and thus fewer potential leakage routes. Subsea Xmas trees are often designed as monoblock trees.

When wells are being constructed this type of Xmas tree is installed after the completion string is in position and has been pressure tested.

![Solid Block Xmas Tree](image)

Figure 18

Horizontal Xmas tree
A relatively new Xmas tree concept which is used on subsea wells is the “horizontal Xmas tree”, in which the valves are located to the side of the well bore so that the completion can be run in and out of the well without having to retrieve the Xmas tree. The valves located at the side of the wells are:

- Two master valves (or wing valves)
- Kill valve and chemical injection valve (these are mounted on the pipework between the master valves).

On top of the well stands the “tree cap”, and in the tubing hanger under the tree cap one or two mechanical plugs are installed.
Figure 19
Certain wells are completed with double completion strings, where each string has a separate set of functions; injection/production, gas/water, oil/water or gas/oil.

In such cases the Xmas tree is equipped with a double set of valves (see valves listed in section 1.1).

Subsea Xmas tree
Trees of this type are often designed as dual trees with two bores; one for production and a smaller one for annulus functions.

The production bore is equipped with the same set of valves as on a standard surface Xmas tree, while the annulus bore has hydraulically actuated wing and master valves. Some Xmas trees also have a mechanically operated master valve on the same bore (for use in ROV/diver interventions).

Some Xmas trees also have X-over valves between the production bore and the annulus bore. This allows the line to the annulus to be used to pump fluids or chemicals downhole or into the well-flow passing through the Xmas tree, or simply to bleed off pressure, if a hydrate plug has built up in the flow tubing between the Xmas tree and the topside installations.

9.4 Operational preparations

A standard requirement is that the valves in a Xmas tree should be pressure tested/inflow tested before operation of the well commences. This is done in order to ensure that the valves are tight; i.e. that they function as barrier elements.

Using leakage rate as a criterion is difficult, as suitable measurement equipment does not exist. Leakage rate normally has to be converted to pressure rise via theoretical calculations. Such calculations involve volume, where the real volume may differ from the theoretical volume.

Consider for example a suspect hydraulic master valve into which we pump 5 - 10 litres of grease in order to clean its sealing surfaces. If we perform an inflow test and measure the pressure rise in the “cross” the volume of grease that has been pumped in (including in the cross) will reduce the volume into which the valve is leaking, for example from 20 to 15 litres, and this in turn will affect the results/acceptable pressure rise. The volume in the cross will also be uncertain if the cross has split gate valves, which have an “extra” volume between the gates.

Valves are normally regarded as tight if their leakage rate is less than 0.4 l/min liquid or 25.5 Sm³/gas.
It is good operational practice always to have several valves available as barrier elements, particularly on workovers of older wells, where valves may be suspect because of deposits.

When rigging up well operation equipment on top of Xmas tree, the operational team takes over control of the hydraulic master valve and the down-hole safety valve in order to avoid the possibility, for example, of the control-room operator closing the hydraulic master valve while a wireline or other piece of equipment is being run through the Xmas tree. Some hydraulic master valves can also be mechanically locked in the open position. The hydraulic master valve and the DHSV are controlled from the Local Control Panel.

When the downhole equipment is out of the well one or more valves in the Xmas tree are usually shut in order to be sure that we have full control of the well when we bleed off the pressure in the intervention equipment.

It is important to be aware of the number of turns needed to open and close manually operated valves, and of which items of equipment the hydraulically actuated master valve has been tested to cut.

Opening valves under differential pressure conditions (including valves in a double block situation) can damage their sealing mechanisms as a result of flushing and high mechanical loads. Differential pressure can result in pressure damage to intervention equipment such as tool strings that are hanging in a lubricator.
10. OTHER MECHANICAL EQUIPMENT IN THE COMPLETION STRING

10.1 Storm choke

Storm chokes, or directly controlled safety valves, are placed in the well but are not controlled from the surface via a control line. These valves are often located in the lowermost nipple profile in the completion string with the aid of wireline equipment. There are two types of such valves:
Figure 20

Storm Choke

Connection for Lock
Spring
Pre-charge Connection
Ball
Excess flow

If the flow through the valve increases greatly (e.g. in a blowout) the pressure differential across the valve rises and a spring closes the choke.

Pressure-activated
The downhole hydrostatic pressure holds the valve open. If the flow should suddenly increase the pressure will fall and and the valve will close with the aid of a spring and a pre-loaded nitrogen charge.

10.2 Flow coupling/blast joint

This is a thick-walled pipe section that is placed in areas of turbulent flow; e.g. after the DHSV, nipple, circulation equipment, pipe sections that pass perforations. Its ID is identical to that of the other pipe sections in the completion string, while its OD may be the same as the OD of the connections.

10.3 Wireline entry guide

This is equipment that is located at the bottom of the tail-pipe (particularly if it is not a monobore well) in order to enable intervention tools to enter the completion string without catching. Entry guides can have a ½ muleshoe or a full muleshoe.

Sealstems often have entry guides at their ends to make it easier to enter the liner PBR. Muleshoes are now available that rotate a certain number of degrees if the completion string takes a weight, i.e. if it is impossible to enter the PBR, on the next attempt we have the muleshoe/entry guide which has automatically rotated a certain number of degrees (so that we avoid having to rotate the whole completion string, which could damage the control lines).
10.4 Plugs

Blanking plug
This is wireline installed in a nipple profile. Such plugs are called “positive” if they can take pressure from both sides. Due to their large diameter, it takes some time to run these plugs, while they may be difficult to release if the pressure is not completely balanced across them.

Bypass blanking plug
This plug has a pressure-equalisation function. Two trips are normally needed to set such plugs; one with the plug itself, and another with a prong, and two trips to pull them; pick up the prong = equalise pressure over and under the plug and pick it up.

Check valve
This valve is installed as part of a plug. It is also known as a “standing valve”. The valve seals the well from above and is used in pressure testing the completion string and setting the production packer. Some designs allow wirelines to remain connected during the pressure-testing process, so that the plug or valve can be pulled immediately after a successful test.

Pump-through plug
This is a check-valve which maintains pressure only from below. It can be installed ahead of a well-killing operation.

Pump-open plug
This plug is completely tight until an internal plate is ruptured by pressure applied from the surface, producing full two-way communication through the plug.

Pressure cycle plugs
These are often used in monobore wells to set wells and wells with open-hole reservoirs. The production packer is set by applying pressure to the plug. The plug is then cycled by pressuring up or bleeding down until it opens. Certain designs of these valves do not restrict the ID of the completion string (Ocre valves).

Pump-out plugs
These plugs are installed in a nipple profile. Pressuring up above the plug causes it to split in two and the lower part falls down into the well. This type of plug offers a larger area of flow, but still restricts the well flow (through the part of the plug that remains in the nipple profile).

Retrievable bridge plugs
These are the most frequently used plugs, not least in monobore wells, which do not have nipple profiles. They can be set by wireline or coiled tubing, and are pulled using the same types of intervention equipment. The plugs are fitted with packing elements and slips which operate in both directions.
11. COMPLETION QUIZ:

1. What is the primary function of the production packer in a producing well?
   a) To carry the weight of the production string.
   b) To keep the completion fluid inside the annulus.
   c) To isolate the production annulus.
   d) To anchor the base of the production string.

2. How do we isolate a production packer between the inner annulus and the production string?
   a) By isolating the inner annulus from the product flow and from the casing below the production packer.
   b) By isolating the production string in the packer bore.
   c) By installing it in a tie-back packer receptacle.
   d) By hydraulic control from the surface.

3. What types of production packer are available for well completions?
   a) Permanent.
   b) Retrievable.
   c) Bridge Plug.
   d) Pump-through.
   e) Check valve.

4. What is the definition of a retrievable production packer?
   a) It can be removed by milling.
   b) It is fixed and can only be removed together with the production string.
   c) It is fixed on the production string.
   d) It can be set and retrieved by wireline.
   e) It can only be retrieved by means of special retrieval tools.
5. What is the primary function of a sliding sleeve?
   a) To allow communication between the production string and inner annulus.
   b) To block the product flow
   c) To block the inner annulus

6. How is temporary communication established between the production string and the inner annulus in order to permit well circulation?
   a) By opening the sliding sleeve door.
   b) By installing a circulation valve in a side pocket mandrel.
   c) By perforating the production string.
   d) By connecting the production string to the inner annulus at the surface.

7. Where is a sliding sleeve usually located when used for a circulating device?
   a) Between two production packers, to allow production from a single zone.
   b) Below the production packer in a normal completion.
   c) Immediately above the production packer in a normal completion.

8. Which of the following statements are correct in regard to circulation devices in a well killing operation? (Select two answers)
   a) Check that the pressure classification is adequate for the job
   b) Check the pressure is equalised before opening.
   c) Check the circulating device is fully opened.
   d) Check the tail-pipe plug has been installed before the sliding sleeve is opened.
   e) Check that the catcher has been installed below the sliding sleeve door.

9. If the sliding sleeve cannot be opened for circulation, how is circulation established?
   a) Make a hole in the tubing with a tubing punch.
   b) By releasing the production packer
   c) By connecting the production string to the inner annulus at the surface.
   d) By retrieving the downhole safety valve (DHSV/SCSSV).
10. What is the purpose of the side pocket mandrel?

   a) To allow communication between the production string and the production annulus.
   b) To enable the production string to be plugged.
   c) To enable the wireline retrievable safety valve to be set.
   d) To establish a profile for setting flow control devices.

11. How are well fluids prevented from flowing into the production annulus when a side pocket mandrel is being used for gas-lift or chemical injection?

   a) By means of a pressure differential across the side pocket mandrel.
   b) By means of a check valve in the gas lift valve.
   c) By means of a venturi effect across the side pocket mandrel.

12. What type of valve is installed in a side pocket mandrel to block flow in both directions when it is not in use?

   a) A “dummy” valve.
   b) A gas-lift valve.
   c) A gate valve.
   d) A chemical injection valve.
   e) A circulation valve.

13. Why do we install downhole safety valves (DHSV/SCSSV)?

   a) To close in the well to allow maintenance of topside equipment.
   b) To close in the well when production is to be shut down.
   c) To control the rate of flow from the well.
   d) To stop production if a topside valve is opened accidentally.
   e) To close in the well in an emergency.

14. Why do we install annulus safety valves?

   a) They are used instead of downhole safety valves in the production string.
   b) To shut off flow to the annulus.
   c) To prevent back-flow of gas from an annulus with gas-lift.
15. What is the main reason for using nipple profiles in a completion?
   a) To allow flow control devices to be set.
   b) To reduce flow from the well.
   c) For depth control during wireline operations.

16. How is equipment locked into nipple profiles?
   a) By means of slips.
   b) By means of No-Go shoulders on the equipment.
   c) By means of locking dogs in suitable milled profiles in the nipple profile.
   d) By means of expanding rubber elements in the nipple profile.
   e) By means of elastomer packing elements in the polished bore of the nipple profile.
   f) By means of metal-to-metal seals.

17. What is the primary function of the No-Go shoulder on the equipment stopper?
   a) To guide the locking dogs on a wireline tools to a matching nipple profile.
   b) To prevent equipment falling out of the production string when the shoulder is installed on the bottom nipple profile.
   c) To relieve forces when there is a pressure differential across the equipment.
   d) To lock a wireline tool into the nipple profile.

18. Which statement determines the best setting depth for the downhole safety valve (DHSV/SCSSV)?
   a) It should be set at a depth at which sabotage of the valve would be impossible.
   b) It should be set such that the volume of hydrocarbons that can leak past a closed valve will be minimal.
   c) It should be set at such a depth that a topside collision or explosion would not be capable of damaging the valve itself.
   d) It should be set below the “cratering depth” in case of a blowout round the casing.
   e) It should be set just above the production packer in order to keep the well pressure as low as possible.
   f) It should be set below the depth at which drilling equipment from adjacent wells could impact it.
19. Which two types of downhole safety valve are normally used in well completions?
   a) Coiled-tubing Retrievable DHSVs.
   b) Tubing-retrievable DHSVs.
   c) Wireline-retrievable DHSVs.
   d) Permanent DHSVs.
   e) Temporary DHSVs.

20. Which of the following downhole safety valves are sub-surface controlled? (Select two answers)
   a) Differential pressure valve.
   b) Ambient pressure valve.
   c) Wireline-retrievable valve.
   d) Tubing-retrievable valve.
   e) Ball valve.
   f) Flapper valve.
   g) Automatic valve.

21. Which type of downhole safety valve (DHSV) has the largest internal diameter in a given size of production tubing?
   a) Wireline-retrievable valve.
   b) Tubing-retrievable valve.
   c) Ambient pressure valve.
   d) Pressure differential valve.

22. What types of closing mechanisms are normally used on surface controlled wireline-retrievable DHSV? (Select two answers)
   a) Poppet valve.
   b) Flapper valve.
   c) Plug.
   d) Ball valve.
   e) Sleeve.
   f) Gate valve.
23. What is the principal advantage of using a wireline-retrieval DHSV?
   a) It is a simple design and construction.
   b) It can be installed after the production string has been run into the well.
   c) It can be removed when well interventions are to be performed.
   d) It can be retrieved and replaced with a new valve.

24. What is the definition of a permanent packer?
   a) It can be set and retrieved on wireline.
   b) It can only be retrieved by a special pulling tool.
   c) It is fixed to the completion string.
   d) It can only be retrieved by milling out.

25. What is the first action to take to re-instate production in a well with a failed tubing retrievable downhole safety valve?
   a) Perform a workover
   b) Lock the valve mechanism open.
   c) Lock the valve mechanism open and install a wireline insert valve

26. Why is an annulus safety valve installed?
   a) To stop flow from the annulus.
   b) In place of a tubing safety valve.
   c) For a gas lifting well, to prevent back flow of injected gas to surface.

27. How are sub surface controlled downhole safety valves closed?
   a) By pressure.
   b) By wireline.
   c) By fluid density
   d) By temperature.
28. How does a flow control device seal within the nipple bore?
   a) Metal to metal seal.
   b) With Mandrel locking dogs into the matching nipple recess.
   c) On No-Go shoulders.
   d) With slips.
   e) With elastomeric packing in a polished nipple bore.

29. How is a surface controlled wireline retrievable DHSV run downhole in the open position?
   a) With a lock open sleeve.
   b) With lock-in hydraulic pressure.
   c) With an automatic J-device.
   d) With a prong on the lock mandrel running tool.

30. Where is a packer, normally positioned in the completion string?
   a) Below the perforations
   b) As close to the tubing hanger as possible.
   c) Halfway between the perforations and the tubing hanger.
   d) Above but close to the top perforation.

31. What are the main functions of the tubing hanger? (two answers)
   a) It supports the weight of the completion string.
   b) It allows communication from inside the completion to the completion annulus through the control ports.
   c) It isolates the completion from the completion annulus.
   d) It is where the well is closed by a pressure control line.

32. What is the main purpose of the SSD?
   a) To close the tubing bore.
   b) To provide communication between the annulus and tubing.
   c) To close off the annulus.
33. Do downhole safety valves prevent flow in both directions when closed?
   a) Yes.
   b) No.

34. What are the main purposes of a side pocket mandrel? (two answers)
   a) To provide a profile for landing flow control devices.
   b) To provide a communication path between the tubing and casing annulus.
   c) To plug the tubing.
   d) To act as a receptacle for gas lift, chemical injection, circulating of dummy valves.
   e) To act as a receptacle for a wireline safety valve.

35. How does a surface controlled wireline retrievable downhole safety valve make hydraulic communication with the control line?
   a) Between to packing seals once the lock mandrel is set.
   b) Through a hydraulic stab.
   c) Through an open SSD.

36. Which of the following statements about a Xmas tree are true? (two answers)
   a) When the valves are closed, it is necessary to close as tightly as possible.
   b) All valves on a Xmas tree take 25 turns to open or close.
   c) After closing, a manual valve should be backed out part of a turn (1/4 turn).
   d) Counting the turns while operating the valve can show if there is an obstruction in the valve.
   e) There is an indicator to show how many turns are still required to fully close the valve.

37. From which direction are downhole safety valves designed to prevent fluid flow?
   a) Above.
   b) Below
   c) Both directions.
38. Is a downhole safety valve a closable barrier?
   a) Yes.
   b) No.

39. What is the primary factor that determines the setting depth of a downhole safety valve?
   a) It should be below any possible depth where damage could occur to the valve from an accidental surface impact or explosion.
   b) It should be below any possible depth where hydrates could form and jam the safety valve.
   c) It should be below any shallow gas pockets.
   d) It should be below any possible depth where damage could occur to the valve due to sabotage.

40. Identify the components on the conventional Xmas tree.

   a) Lower master valve.
   b) Swab/crown/tree cap.
   c) Kill wing valve.
   d) Adapter flange.
   e) Upper master valve.
   f) Body.
   g) Failsafe valve.
   h) Swab valve.
   i) Flow wing valve.
   j) Choke.
11.1 Completions Quiz: Answer Key

1. c
2. a
3. a & b
4. b
5. a
6. a & b
7. c
8. b & c
9. a
10. a
11. b
12. a
13. e
14. c
15. a
16. c
17. a
18. c
19. b & c
20. a & b
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22. b & d
23. d
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26. c
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28. e
29. d
30. d
31. a & d
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b 1
c 10
d 8
e 6
f 9
g 4
h 2
i 3
j 5
CHAPTER

3

WIRELINE EQUIPMENT
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1. SURFACE-RELATED EQUIPMENT FOR PRESSURE CONTROL FOR WIRELINE OPERATIONS: GENERAL CONSIDERATIONS

Wireline-operated pressure-control equipment is installed on top of, or as an extension of, the well’s Xmas tree. The rig usually consists of a spacer, double blind shear BOP and Wireline valve, adequate lengths of lubricator as required for the length of the toolstring and on top of everything, a stuffing box.

(It is not always possible to install the BOP directly on top of the Xmas tree).

In connection with special operations such as during completion, a circulating head or flow head is installed between the well-head and the wireline safety valves. This permits circulation of the completion fluid and pressure testing of the operation equipment when this has been rigged up.

A wireline operating unit also includes a power pack and a winch/wireline operator’s cabin.

We distinguish three types of wirelines: slickline, electric line and braided line. The pressure control equipment for electric and braided lines is identical for the same wireline dimensions.
Figure 2: Pressure Control Equipment Rig Up
Figure 3: The IWCF Barrier Philosophy
2. **STUFFING BOX (SEE FIGURE 4)**

The stuffing box maintains the pressure from the lubricator while the wireline is being led through it and into the lubricator.

During this operation, the packing unit is regulated either manually or hydraulically. In addition, all stuffing boxes incorporate a blow-out plu/valve which will close fluid flow if the wireline breaks and is blown out of the stuffing box.

Before an operation we should check the stuffing box and determine whether the set of packers is in good condition. If there is any sign of wear it should be replaced with a new set of the appropriate dimension for the wireline which is to be used in the operation. We should also make sure that the blowout plug has been inserted the right way up, i.e. with it conical end pointing upwards.

The stuffing box is the primary barrier during a slickline operation.
Figure 4: Slickline Manual Stuffing Box

- Gland nut
- Upper bushing/gland
- Packing
- Quick union collar
- Bleed valve screw
- Plunger
3. **LUBRICATOR**

The lubricator enables us to keep the wireline string in the tubing while we equalise the pressure between the lubricator and the well before we start the operation, and between the lubricator and atmospheric pressure during unrigging after the operation has been completed. A lubricator consists of cylindrical pipes connected by quick-release joints as needed to make up the required length.

The quick-release joints are fitted with O-ring seals. Every time the system is rigged up we should check that the O-rings are in good condition.

At the lower end of the lubricator we find a bleed-off port on which to mount the lubricator manifold, which normally consists of a needle valve nearest the lubricator, a manometer and a needle or ball valve (in the form of a T) for pressure venting. If we wish to pressure test the lubricator using the manifold we install a T-joint after the manometer.

It is important to install valves capable of withstanding the same pressure as the rest of the equipment.
Figure 5: Slickline Pressure Control Stack
Figure 6: Hydraulic Tool Catcher
Figure 7: Lower Lubricator Section
Figure 8: Chemical Injection Sub
Figure 9: Hydraulic Tool Trap
4. WIRELINE BOP

The wireline BOP is a blind ram that is located between the lubricator and the shear ram. Closing the blind ram enables us, for example, to replace packers or seals in the stuffing box or stripper, or to install (new) equipment such as a cutter.

The wireline BOP is usually hydraulically actuated. Two cylinders activate the valve assembly and close around the wire without damaging it. Each cylinder is connected to two hydraulic hoses (for opening and closing). The BOP can also be operated manually.

It is important to ensure that when the guide-shoe on the one side of the ram seal is facing upward the guide-shoe on the other is facing down. Guide-shoes that are not in the correct position can cause serious damage when the BOP is opened or closed. Similarly, it is important to ensure that the correct type of ram seal is utilised and that the outermost seal is facing upwards, as the pressure in the well helps to press the seal upwards and keep it tight.

The wireline BOP should be functionally tested before operation.

Make sure that the rams are in the fully withdrawn (open) position before the start of the operation, otherwise both the equipment and the rams themselves may be damaged as the string passes through the BOP.

During the operation the equalisation valve must be closed and should only be opened in connection with activation of the wireline BOP.

When braided cable is being utilised a double wireline BOP is used. In principle, this consists of two single wireline BOPs, the lower of which is turned upside down. Between these there is a port for pumping in grease which seals the valve against the well pressure. When the valves are to be closed, the upper ram is closed first, followed by the lower, after which the grease is pumped in.
Manual BOP

Figure 10: Slickline Single Ram Manual BOP
Figure 11: Slickline Single Ram Hydraulic BOP
Figure 12: Wireline BOP
Figure 13: Slickline Ram Assemblies
5. SHEAR/SEAL BOP (SEE FIGURE 14)

The shear/seal BOP is installed between the well’s Xmas tree and the wireline BOP. It comprises the third barrier in the wireline operated pressure control system. The Shear-seal BOP is hydraulically actuated, but it can also be operated manually.

The valve stack is equipped with a shear ram which, when closed, also functions as a seal BOP. The valve is actuated when there is a need to cut the wire at the surface, and to avoid having to utilise the Xmas tree, which might lead to damage to the valves.

At present, it is normal to install stacks of three-valve and even four-valve BOPs. In such stacks, the last BOP is usually the shear/seal BOP. It is also usual to put together BOP systems that are suitable for both slickline and braided cable, if both types of wireline are going to be used in the course of the operation.
Figure 14: PES Wireline Cutter Valve (Shear/Seal BOP)
Figure 15: Circulating Head
6. GREASE INJECTION CONTROL HEAD (SEE FIGURE 16)

The grease injection control head has the same functions as a stuffing box when braided cable is being utilised. Grease is pumped in through the lower nipple and injection port and up through the wireline and the seal tubes. A minimum of three lengths of seal tubing is essential on an injection head to reduce the pressure and keep it tight with the aid of a hydraulic packer unit on the top of the injection head. The pressure is controlled from a separate panel and is usually to the unit by means of an air-driven pump. The grease is withdrawn through a return nipple below the packer unit.

Before the start of operations we should check that the sealing tubing is suitable for the dimensions of the wireline. Excessively large sealing tubing or a worn wireline will mean excessive grease consumption.

We should also make sure that sufficient grease is available for the complete operation before we start working.
Figure 16: Grease Injection Head
Figure 17: Line Wiper
Safety check union/sub

The safety check union/sub is intended to retain the pressure if the wireline breaks or is pulled out of the wireline head. It is installed just below the injection head and is a check valve in the form of a ball which is pressed against a non-extrusion ring/seating.

Before installation and use, the valve should be checked, and if any damage is found the ball and its brass seating should be replaced.
Figure 19: Electric line Dual BOP
Figure 20: Braided line pressure control equipment
7. PRESSURE TESTING AND OPERATION

Following rigging of the complete wireline stack, it is usual to functionally test and pressure test the assembly.
8. WIRELINE EQUIPMENT: QUIZ

1. What are the advantages of installing a wireline BOP directly on top of the Xmas tree? (Select three answers)
   a) Provides good access to the BOP (shorter distance).
   b) Less potential leak paths between barriers
   c) Permits use of full-bore tools
   d) Possibility of locking full-bore tools in the Xmas tree.
   e) Maximise the length of lubricator above the wireline BOP

2. With a wireline tool stuck in the Xmas tree and the tool string passed through the BOP, the wireline is pulled out of the rope socket. What prevents the well from flowing out through the stuffing box?
   a) The stuffing box packer
   b) The stuck tool string
   c) Killing the well
   d) The stuffing box plunger.

3. In the course of rigging the slickline pressure-control equipment we find that the stuffing box gland nut has been screwed fully in. What measures should we take?
   a) Check that the gland nut is screwed well in
   b) Open up the gland nut and fill the stuffing box with more packers
   c) Repack the stuffing box with a new packer
   d) If a pressure test of the stuffing box gives a satisfactory result, leave it as it is.

4. Why is the lower ram installed upside-down when grease injection is being performed on a dual wireline BOP?
   a) The lower ram can be installed in either direction
   b) It is a useful method of balancing the BOP
   c) In a standard configuration, the BOP maintains pressure from below
   d) The lower ram maintains lubricant pressure, not well pressure.
5. What is the function of an equalizing valve in a BOP?
   a) It enables lubricator pressure above and below the BOP to be measured
   b) It enables chemicals and lubricant to be injected into the lubricator
   c) It allows the pressure to be equalized above and below a closed ram
   d) It produces hydraulic power to open the closed ram.

6. Which of the following actions must be performed before the lubricator is broken off above a closed wireline BOP?
   a) Bleed off the well pressure above the closed wireline BOP
   b) Perform an inflow test of the wireline BOP
   c) Screw in the manual stems in order to lock the hydraulic rams
   d) Note the well pressure below the closed wireline ram
   e) Kill the well
   f) Raise the pressure on the wireline BOP.

7. Which of the following actions must be performed before a riser section or lubricator is exposed to well pressure?
   a) Pressure test the section to the minimum shut-in wellhead pressure
   b) Check the pressure rating is at least equal to the max operating pressure
   c) Check that the sealing surfaces and O-rings are in good condition
   d) Check that the hydraulic pump is connected
   e) Pressure test the lubricator
   f) Make sure that the lubricator is in a vertical position.

8. In which of the following situations should an additional wireline BOP be installed?
   a) For fishing operations
   b) If a leak had occurred in the primary BOP
   c) In order to lengthen the lubricator
   d) When operating in a highly deviated well.
9. Some of the components in the following figure are numbered. Note the correct number in the appropriate box below.

[Diagram of Lubricator Section]

- [ ] a) Body
- [ ] b) Coupling
- [ ] c) Quick union seal
- [ ] d) Top connection.
10. Some of the components in the above figure are numbered. Note the correct number in the appropriate box below.

Slickline Stuffing Box

- a) Plunger
- b) Gland nut
- c) Upper bushing gland
- d) Bleed valve screw
- e) Packing
- f) Quick union collar
11. Some of the components in the figure are numbered. Note the correct number in the appropriate box below.

- a) Xmas tree
- b) Grease control head
- c) Pack-off pump
- d) Dual BOPs
- e) Riser
- f) Lower master valve (LMV).
12. Some of the components in the figure are numbered. Note the correct number in the appropriate box below.

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<thead>
<tr>
<th>Number</th>
<th>Description</th>
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<tbody>
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<td>Grease inlet</td>
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<td>2</td>
<td>Hydraulic oil inlet</td>
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<td>3</td>
<td>Grease-head body</td>
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<tr>
<td>4</td>
<td>Drain hose</td>
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<td>5</td>
<td>Flow tube</td>
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</table>
13. What are the main purposes of the blowout preventers? (Select two answers)
   a) To guarantee safe operation and maintain control of the well
   b) To offer better protection than the stuffing box
   c) To clean the wireline when it is pulled from the hole
   d) To enable any leakages that occur in connections above the BOP to be repaired.

14. In which of the following situations would a wireline BOP be activated (closed)?
   a) To check or repair the packer in the stuffing box
   b) To fish up a tool if the wireline breaks
   c) To install a wireline tool
   d) To clean the wireline when it is pulled from the hole.

15. Which of the following ram configurations are correct for working with braided cable?
   a) Braided inverted; Braided normal; Shear seal
   b) Braided normal; Shear seal; Braided inverted
   c) Braided normal; Braided inverted; Shear seal
   d) Shear seal; Braided inverted; Braided normal.

16. Which closable barrier is utilised if a slickline breaks off down-hole and is forced out by the well pressure?
   a) The down-hole safety valve (DHSV)
   b) The BOPs
   c) The blowout plug or internal safety valve in the stuffing box
   d) The check valve in the grease control head.
17. Some of the components in the above figure are numbered. Note the correct number in the appropriate box below.

- [ ] a) Top connection
- [ ] b) Equalisation valve
- [ ] c) Bottom sub
- [ ] d) Ram inner seal
- [ ] e) Piston
- [ ] f) Ram.

18. Which of the following statements is correct when a Single ram BOP is being used?

- a) It only maintains pressure from above
- b) It only maintains pressure from below
- c) It maintains pressure from both above and below.
19. What is a 7 1/16” 690 bar (10,000 psi) flange?

   a) This flange is designed for “RX ring” packers.
   b) This flange has been tested to 690 bar (10,000 psi) and operates at pressures of up to 345 bar (5,000 psi).
   c) This flange has an operating pressure of 690 bar (10,000 psi) with an inside diameter (ID) of 7 1/16”.
   d) This flange has an outside diameter (OD) of 7 1/16” and an operating pressure of 690 bar (10,000 psi).

20. What will be the result of installing a 7 1/16”, 345 bar (5,000 psi) flange on a BOP stack with an operating pressure class of 690 bar (10,000 psi)?

   a) The pressure class will still be 690 bar (10,000 psi).
   b) The pressure class will be reduced to 345 bar (5,000 psi).
   c) The pressure class will be reduced to 517 bar (7,500 psi).

21. What does the expression “6BX” refer to in a flange?

   a) Type
   b) Trademark from CIW
   c) Dimensions
   d) Make
   e) Serial number

22. If the stuffing box gland was screwed fully home, what action should be taken?

   a) Re-tightening the gland nut.
   b) Back out the gland nut.
   c) No action should be taken if the stuffing box passes the rig up test.
   d) Re-pack the stuffing box with new stuffing box packing.
23. Identify the primary, secondary and tertiary barrier elements in the above well diagram, when the wireline is in the well. Note the correct numbers of the components in the boxes below.

   a) Primary
   b) Secondary
   c) Tertiary.

24. If the stuffing box gland was screwed fully home, what action should be taken?
   a) Re-tightening the gland nut.
   b) Back out the gland nut.
   c) No action should be taken if the stuffing box passes the rig up test.
   d) Re-pack the stuffing box with new stuffing box packing.
25. Where is the ball check valve (safety union) positioned in the braided line surface pressure equipment rig up?
   a) Above the BOPs.
   b) Below the BOPs.
   c) Below the grease injection head.
   d) Below the chemical injection sub.

26. What does a 13 5/8 inch, 1035 bar (15,000 psi) flange stand for?
   a) The flange has 1035 bar (15,000 psi) test pressure and 690 bar (10,000 psi) working pressure.
   b) The flange has 13 5/8 inch OD and 690 bar (15,000 psi) working pressure.
   c) The flange is designed for RX type ring gasket only.
   d) The flange has a 1035 bar (15,000 psi) working pressure and 13 5/8 inch ID.

27. During a slick line operation, the surface equipment rig up leaks at the connection between the top two lubricator sections. Which secondary barrier must be closed to make the well safe and allow the leak to be repaired?
   a) Upper master valve.
   b) Stuffing box.
   c) Swab valve.
   d) DHSV.
   e) Blowout preventer.

28. How does the slick line stuffing box seal around the wire?
   a) By applying hydraulic pressure into the packing element cylinder.
   b) By applying hydraulic pressure to push the lower bushing/gland.
   c) By wellhead pressure pushing up on the lower gland bushing.
   d) By a packing nut or piston pushing down on the upper bushing/gland which forces the packing elements to seal around the wire.
29. What is the main advantage of wireline units over other types of well service units?
   a) Wireline units can do perforation operations.
   b) Coiled tubing units cannot rotate tools in the hole.
   c) Economics, due to the speed in which they can rig up complete a job and rig down.
   d) All types of logging are done by means of wireline.

30. What is one of the main disadvantages of using a wireline unit?
   a) Usage is limited in high angle and horizontal wells.
   b) They are limited to slick line work.
   c) Lubricator assemblies are complicated and require special attention.
   d) Impression blocks are difficult to interpret.

31. Where do most of the wireline operations take place?
   a) At the top of the well.
   b) Through the tubing or work string.
   c) Below the production packer.
   d) Above the production packer.

32. Which statement is true concerning wireline units?
   a) There is no need for blowout preventers on wireline jobs.
   b) Wireline blowout preventers and valves are similar to pipe rams in operation.
   c) The blowout preventer stack is supported by a telescoping gin pole.
   d) Ram type preventers cannot be used because they do not form a good seal around the wire.

33. When working on the well under pressure, wireline lubricators are usually installed above the master valve on the tree.
   a) True.
   b) False.
34. Which of the following is not a component of the lubricator assembly?
   a) Control (needle) valve.
   b) Riser sections.
   c) Rope sockets.
   d) Various valves and unions.

35. What is the main purpose of having a ball check valve or safety check union installed below the grease injection head when running braided line?
   a) To clean the grease off the braided line while pulling out of hole.
   b) To prevent the grease and well fluid contaminating each other.
   c) To prevent the escape of well fluid through the grease head if the cable breaks at surface.
   d) To hold chemicals in the chemical injection sub at all times.

36. After closing the wireline BOP and before breaking out the lubricator to lay it down, which of the following actions must be carried out? (three answers)
   a) Kill the well.
   b) Inflow test the wireline BOP.
   c) Increase the pressure against the wireline BOP from the top.
   d) Screw in the manual stems to lock the hydraulic rams.
   e) Bleed off the well pressure above the closed wireline BOP.

37. When the slick line is broken and lost down hole, the plan is to fish the slick line with braided line. Which procedures are recommended in order to perform this operation safely? (two answers)
   a) It is necessary to rig up both slick line and braided line BOPs before the fishing operation.
   b) The lubricator must be changed out to one of a higher rated working pressure.
   c) Redress the slick line BOP into a single braided line BOP.
   d) It maybe necessary to pick up an extra lubricator to accommodate the fishing tool string and the slick line tool string.
38. Which one is the primary barrier during a slick line operation?
   a) Wire line BOP
   b) Lubricator
   c) Stuffing box
   d) Master valve on Xmas tree

39. A device is dropped in the well for the purpose of cutting the wireline at the bottom is called?
   a) A rope socket.
   b) Hydraulic jars.
   c) A go-devil.
   d) A spear.

40. Identify some of the numbered components on the manual single ram wireline BOP. Note the correct number in the appropriate box.
41. Identify some of the numbered components on the hydraulic single ram wireline BOP. Note the correct number in the appropriate box.
42. Identify some of the numbered components on the wireline stuffing box. Note the correct number in the appropriate box.

- a) Hydraulic connection
- b) Piston
- c) Upper gland
- d) Packing
- e) Plunger
- f) Quick union collar
- g) Lower gland
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CHAPTER 4

COILED TUBING
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1. **COILED TUBING WITH SURFACE EQUIPMENT**

This technique is based on running a narrow thin-walled tube into a pressurised well by means of a mechanically driven belt. The coiled tubing itself is stored coiled up on a drum or reel. In theory, there are no limits as to the depth to which one can go in the well, depending on the size (length) of the coils, the well profile, the pulling capacity of the equipment and the strength of the coiled tubing.

Most operations can be performed using coiled tubing. The advantages of this type of equipment are that it can be easily transported, rigged up and unrigged relatively rapidly and that it is quick to bring into operation. Furthermore, the equipment has become safer in the course of the past 10 - 15 years thanks to technical improvements such as better steel quality, shaped string, welding procedures and the H₂S problem.

The disadvantages of the equipment are that there are limits to the flexibility of the coiled tubing and the tubing wall is relatively thin compared to the drill-string. Nor can the coiled tubing string be rotated.

The topside equipment consist of a control house, power supply unit with fluid tanks, the coiled tubing reel, tubing injector, and riser/lubricator system with BOPs (see Figure 1).
Figure 1: Coiled tubing pressure control rig-up
2. LUBRICATOR STACK AND CONNECTIONS

The connections between the pipe-joints and the safety valves are either quick connectors or are screwed together with several flanges and packer nuts.

The most usual set-up in all countries is that the shear/seal safety head is connected to the Xmas tree by means of flanges.

In operations on high-pressure wells, flanged connectors are normally utilised.

Between the tubing injector and the safety valves (BOPs) a hydraulic connector or hydraulic quick latch is installed, making it possible to reconfigure and change the make-up of the bottom-hole assembly (BHA). (See Figure 2).

The distance between the top of the BOP stack and the bottom of the shear/seal safety head limits the length of the down-hole string (sluice length).

If we need an extra long down-hole string, or in connection with running in perforating cannon into the well, the stack can be “expanded” by means of a deployment system.

In principle the deployment system is an extra spool piece fitted with BOPs/annulars, which is installed in the stack between the existing BOPs and the shear/seal safety head. We then run in the lengths needed to make up the downhole string and screw or lock them together by opening and closing the BOPs above the deployment system and the valves on the deployment system itself. Once the whole downhole string has been installed, the coiled tubing is connected to the top section, the tubing injector is coupled up and we can run the string into the well.
Figure 2: Coiled tubing pressure control surface stack
3. STRIPPER/STUFFING BOX

The stripper (or packer, or stuffing box) is located immediately below the injector head and may be either single or dual. The stripper is the primary pressure control barrier and is hydraulically actuated by means of a piston which presses the stripper rubber or packing element against the coiled tubing. The well pressure helps to keep the packing in closed position in certain types of packing element configuration.

The most common types of stripper are conventional strippers, side-door strippers and radial strippers. (See Figures 3, 4 and 5).

The packing elements in all of the above-mentioned types of stripper can be replaced during operations, i.e. while the coiled tubing is in the well. To do this we must first close the lowermost BOP and the pipe and slip rams and bleed off the pressure. In side-door and radial strippers, the packing element can be replaced from the side. This cannot be done in the case of a conventional stripper, in which the packing element must be removed and replaced from the top of the stripper. A double set of strippers is normally used. If one of the packing elements leaks due to wear, the lower stripper can be pressurised (activated) first, allowing the pressure to be bled off from the upper stripper.
Typical packing stack

Figure 3: Conventional stripper assembly
Figure 4: Side-door stripper assembly
Radial stripper assembly

Figure 5  Radial stripper assembly
**Conventional stripper**

The conventional stripper assembly can be used in a single or dual configuration.

In this type of stripper, bushings and packing elements need to be replaced from above.

With the coiled tubing inserted in the stripper stack, only the upper packing in a single configuration, or the upper assembly in a dual configuration can be replaced while the system is in operation.

In a dual configuration, packing inserts and stripper rubbers cannot be replaced once the coiled tubing has passed through the assembly.

Note: Conventional stripper assemblies and single-stripper configurations are not permitted on the Norwegian continental shelf.

**Radial and side-door strippers**

These types of stripper assembly can be used in single or dual configurations.

The stripper insert consists of two parts and can be replaced, together with its bushing, via an access window in the stack.

This set-up allows us to replace bushings and elements without the need to pull the coiled tubing from the stack.

Note: On the Norwegian continental shelf, only dual configurations are permitted.
4. **RAM-TYPE BOP**

The BOPs are located below the strippers and may consist of double, triple or quadruple (quad) BOPs. The BOP stack comprises the secondary barrier.

A double or triple BOP is equipped with the same ram stacks as a quad BOP, but in the form of combinations, i.e. in a double BOP, the upper valve will consist of a blind/shear ram and the lower part will consist of a pipe slip ram. (See Figure 7).

In a quad BOP, the uppermost valve is a blind ram, the second is a shear ram, the third a slip ram and the fourth an lowest, a pipe ram (Figure 6).

If it turns out to be necessary to cut the coiled tubing in the course of an operation, the procedure is as follows:

- Close slip ram
- Close pipe ram
- Close shear ram
- Pull coiled tubing above the blind ram
- Close blind ram.

The BOP assembly is fitted with equalising valves in order to allow the pressure to be equalised across a closed ram before it is opened.

The BOP is also fitted with a kill port.
Figure 6: Coiled tubing quad BOP
Figure 7: Combi coiled tubing BOP

Figure 8: Shear seal valve
Figure 9: Blind ram assembly

Figure 10: Shear ram assembly
Figure 11: Slip ram assembly

Figure 12: Pipe ram assembly
5. SAFETY HEAD BOP OR SHEAR/SEAL BOP

The safety head BOP or shear/seal BOP is a simple shear/seal safety head which is installed as close as possible to the Xmas tree and which is equipped with a shear/seal ram. This BOP comprises the tertiary barrier. (Figure 18).

This shear/seal safety head is usually designed to withstand pressures of up to 10,000psi. It is rather larger in diameter and is equipped with a larger and stronger shear/blind ram that is capable of cutting the largest-diameter coiled tubing, even one containing wireline, if that is being used in the well. After it has been cut, the tubing falls down into the well and swab valve or other valves on the Xmas tree can be closed.

Figure 13: Shear seal assembly
The annular BOP or annular preventer is utilised as a safety head in special operations in which it is necessary to close around long, variable profiles of the bottom-hole assembly (BHA) in the deployment system. The advantage of the annular BOP is that it closes around various pipe dimensions and can also seal the opening when there is no tubing in the hole. See Figure 14).

The annular BOP is normally installed either above or below an existing safety head on the stack.

Annular BOPs are also used as an extra safety system for strippers.

Figure 14: Annular preventer
7. **CHECK VALVES**

Check valves are always installed in the end of the coiled tubing except when we are about to perform reverse out-circulation. (In Norway, the check valve is an element in the barrier philosophy. Reverse circulation, is therefore not permitted during a normal operation).

The check valve is intended to prevent well fluids from entering the string.

Although there are several types of check valve, the most frequently used are flapper valves, usually in a dual configuration. The flapper valves allow balls and plugs to be pumped down in order to operate special equipment in the well. The check valve is normally installed between the end connection of the coiled tubing and the rest of the bottom-hole string. (See Figures 15 and 17).

Pump-down and through-pumping balls or plugs activate specific items of equipment which are installed in the bottom-hole assembly. These are installed via s sluice port which is installed in the centre of the coiled tubing reel in direct connection with the coiled tubing pumping-in system.
Figure 15: Coiled tubing dual-flapper check valve
"EXTERNAL" SLIP CONNECTOR

"O" RING GROVE
SLIPS
"O" RINGS

"INTERNAL" ROLL ON CONNECTOR

CRIMP GROVE

Other types are available.
Disse tetter også om kvellerøret innvendig eller utvendig.

Figure 16:  Coiled tubing end connector
MOTOR HEAD ASSEMBLY = COMBINED END CONNECTOR, CHECK VALVE & EMERGENCY RELEASE TOOL

SLIP END CONNECTOR

DOUBLE FLAPPER CHECK VALVE

EMERGENCY RELEASE

Figure 17: Coiled tubing motor head assembly
Once the coiled tubing stack with the coiled tubing and bottom-hole assembly has been installed and its functions have been tested, the equipment must be pressure-tested. This involves all connections and safety valves that are intended to maintain pressure from the bottom upwards.

The following equipment should also be pressure-tested: all topside lines, joints, connections and equipment on the bottom-hole assembly, the coiled tubing itself and the check valves. The usual procedure is to pressure test the check valves before they are installed on the string ("on the stump" testing).

When the coiled tubing string is being run in it is important to ensure that the coiled tubing does not become crumpled or pressed flat. Before the Xmas tree is opened, the pressure must be equalised by raising the pressure in the stack.

It is normal practice to pump fluid in through the coiled tubing in order to increase the pressure before entering the Xmas tree, and to continue pumping/filling the coiled tubing as we run into the well. This is done in order to prevent the coiled tubing from collapsing due to well pressure.

We must be particularly careful when passing through the Xmas tree, the well safety head assembly and any other equipment installed in the well, not to damage the equipment, crumple the string or get stuck in the well.

It is also important to have kill pills and kill fluid ready to hand. The kill fluid may consist of killing mud, salt water or completion fluid. We must also ensure that a reserve pump is available and in working order.
9. COILED TUBING: QUIZ

1. Some of the components of a conventional stripper shown in the figure below are numbered. Identify the components by marking the boxes with the correct number in the figure.

   1 point for each correct answer

   a) Lower bushing
   b) Non-extrusion ring
   c) Packing insert
   d) Upper bushing/Split cap
   e) Locking pins
   f) Energiser.
2. Identify the different types of stripper illustrated in Figures 1 to 3 by marking the boxes with the correct figure number.  

1 point for each correct answer

a) Conventional stripper assembly
b) Radial stripper assembly
c) Side-door stripper assembly.
3. How do we determine the maximum working pressure of a stripper?

2 points

a) By pressure testing it
b) On the basis of the manufacturer’s pressure-testing data sheet
c) On the basis of type of stripper: conventional, side-door or radial
d) On the basis of the manufacturer’s data sheet on working pressure.

4. What happens when the stripper in the figure is activated?

2 points

a) Hydraulic pressure is applied to the lower bushing, which compresses the packer in an upward direction
b) Hydraulic pressure is applied to the upper bushing, which compresses the packer in a downward direction
c) Well pressure will activate/pack the stripper without the aid of hydraulic pressure
d) Hydraulic pressure is applied to the wellhead pressure port, which compresses the packer in an upward direction.
5. The stripper shown in the figure is activated. If the well pressure increases will this help this type of stripper to be activated/packed any further?

1 point

- a) Yes
- b) No
6. What happens when the stripper illustrated in the figure below is activated?

2 points

a) Hydraulic pressure is applied to the lower bushing, which compresses the packer in an upward direction
b) Hydraulic pressure is applied to the upper bushing, which compresses the packer in a downward direction
c) Well pressure will activate/pack the stripper without the aid of hydraulic pressure
d) Hydraulic pressure is applied to the wellhead pressure port, which compresses the packer in an upward direction.
7. The stripper shown in the figure is activated. If the well pressure increases will this help this type of stripper to be activated/packed any further?

1 point

a) Yes
b) No

8. What is the first thing that should be done after connecting up the hydraulic control hoses to a BOP?

   a) Set the ram energisers in neutral position and pressurise the hydraulic hoses
   b) Install the injector head
   c) Subject all components in the BOP stack to a functional test
   d) Check that the BOP accumulator bank is sufficiently loaded.
9. The following figure shows the standard configuration for a quad coiled tubing BOP. Some of the components in the figure are numbered. Identify them by marking the boxes with the correct number in the figure.

![Quad Coiled Tubing BOP Diagram](image)

- a) Shear ram
- b) Pipe ram
- c) Slip ram
- d) Blind ram
- e) Kill port.

10. The following figure shows the standard configuration for a combi coiled (CT) tubing BOP. Some of the components in the figure are numbered. Identify them by marking the boxes with the correct number in the figure.

![Combi Coiled Tubing BOP Diagram](image)

- 1
- 2
- 3
- 4
- 5
- 6
11. What are the main advantages of using a Combi CT BOP over a Quad CT BOP?

Select 2 answers 3 points

a) The rig-up occupies less height.
b) It is easier to pump kill fluid down cut coiled tubing when the blind ram is closed.
c) It reduces the number of steps involved in an emergency closure of the BOP.
d) It is possible to pump down the annulus between the coiled tubing and the production tubing when the lower ram is closed up on a Combi CT BOP.
e) A Combi CT BOP is more flexible in use.
12. What is the purpose of a Shear/seal BOP?  

- To provide further possibilities of cutting the work over string  
- To replace a Quad or Combi CT BOP  
- To seal around the workover string  
- To enable the workover string to be cut without closing down the well

13. When should an annular BOP be utilised?  

- When the stripper is not available.  
- When it is necessary to pack round tools of different dimensions than the coiled tubing.  
- When extra packing is desirable in high-pressure well workovers.  
- When stripping/running the coiled tubing in a well that is under pressure.

14. What precautions should be taken when stripping through an annular BOP?  

Select 2 answers  

- Lubricate the workover string and coiled tubing  
- Ensure that an annular insert is available  
- Carefully observe the operating pressure on the annulus and weight indicator  
- Check the outer diameter of the components in the BHA drawing (by running/stripping the workover string)  
- Retract the strippers.
15. Which of the two BOP stacks in the above illustration is most suitable for high-pressure coiled tubing operations?

   2 points
   a) Fig 1.
   b) Fig 2.

16. A leak appears in the choke line while the coiled tubing is in the well. In which of the BOP stacks in the above illustration can two barriers be sealed to enable the leakage to be corrected?

   2 points
   a) Fig 1.
   b) Fig 2.
17. The coiled tubing breaks between the gooseneck and the drum. The check valve fails. In which of the BOP stacks illustrated above can the well be secured before kill fluid is pumped down the coiled tubing, returning via the choke line?  
   2 points
   a) Fig 1.
   b) Fig 2.

18. The coiled tubing is in the well. Is it possible to replace the stripper elements in both BOP stacks in illustrations Fig 1 and 2 above, while simultaneously maintaining two barriers?  
   2 points
   a) Yes
   b) No.
19. What is the correct order of assembly, from top to bottom, in a CT Bottom Hole Assembly?
   2 points
   a) Connector, Check valve 1, Release element, Check valve 2, Circulation port, Motor/Drill Bit
   b) Connector, Release element, Check valves 1 and 2, Circulation port, Motor/Drill Bit
   c) Connector, Check valves 1 and 2, Release element, Circulation port, Motor/Drill Bit
   d) Connector, Release element, Circulation port, Check valves 1 and 2, Motor, Drill Bit.

20. What is the purpose of the check valves in a bottom hole assembly?
   2 points
   a) To eliminate the necessity to pressure test the coiled tubing before running it into the well
   b) To protect the bottom hole assembly from exposure to well pressure
   c) To maintain control of pressure if the coiled tubing should fail at the surface
   d) To prevent collapse of the coiled tubing when it is exposed to differential pressure.

21. What is the purpose of a blind/shear ram?
   2 points
   a) To cut the workover string and simultaneously seal the tubing.
   b) To cut the workover string without sealing.
   c) To seal around the workover string in the well.

22. What is the maximum working pressure permitted when we use a 7 1/16” x 345 bar (5000 psi) flange on a BOP with a working pressure of 690 bar (10,000 psi)?
   2 points
   a) The maximum working pressure 690 bar (10,000 psi) is maintained.
   b) The maximum working pressure will be 345 bar (5,000 psi).
   c) The maximum working pressure will be 517 bar (7,500 psi).
23. Which type of gas is used to pre charge accumulator bottles?  
   2 points
   
   a) Air
   b) Nitrogen
   c) Oxygen
   d) Carbon dioxide.

24. Some of the components in the figure below are numbered. Identify the components by marking the boxes with the correct number in the drawing.
   1 point for each correct answer

   a) Opening chamber cover
   b) Closing chamber port
   c) Valve body
   d) Pack-off unit
   e) Piston indicator port
   f) Head
25. During a coiled tubing operation the surface equipment leaks from the connection between the quad BOP and the stripper. Which barrier must be closed to make the well safe and allow the leak to be repaired?

   a) Swab valve.
   b) Blind rams.
   c) DHSV.
   d) Upper master valve.
   e) Pipe rams.

26. Which of the following statements is true?

   a) The blind/shear or cutting rams are designed to cut the pipe and any BHA components.
   b) The blind/shear or cutting ram are designed to cut the pipe only, not the BHA.
   c) The blind/shear or cutting rams are assisted in the cutting action by well bore pressure.
   d) The blind/shear or cutting rams are operated at 345 bar (5000 psi) hydraulic pressure.

27. When does an annular BOP need to be installed?

   a) When the stripper ram is not available.
   b) To provide extra security for high pressure operations.
   c) To seal around tools which have different outside diameters than the CT.
   d) To strip the CT into an “under pressured” well.

28. Before a BOP with a rated working pressure of 10 M (690 bar) be initially deployed, it must first pass a “shell proof test”. How much pressure must the BOP withstand to pass this test.

   a) 1207 bar (17,500 psi).
   b) 1035 bar (15,000 psi).
   c) 1380 bar (20,000 psi).
   d) 690 bar (10,000 psi).
29. Which of the following statements is the best description of a coiled tubing tool deployment system?
   a) It is a frame that supports the weight of the injector head.
   b) It is the action of feeding a long BHA through the injector head.
   c) It is a means of running a very long BHA into a live well.
   d) It supports the weight of the injector head and stripper when running coiled tubing on a floater.

30. Coiled tubing is used for reverse circulation operation in a live well by dropping a ball to open circulation sub above the check valve. Which of the following statements is true when pulling coiled tubing out of the hole?
   a) The coiled tubing can be pulled as long as the check valve was tested and still holds pressure.
   b) The reel valve will have to be closed while pulling out to maintain pressure in the coil.
   c) Continue reverse circulation to maintain proper internal pressure in the coil.
   d) While pulling out of hole there is no mechanical barrier at the bottom of the coil to prevent well bore fluids from entering the coil.

31. Which of the following statements about reverse circulation with coiled tubing are true? (two answers)
   a) It is normally used when pipe is stuck.
   b) It will lower downhole pressure.
   c) It can lift solids more easily when in a large hole.
   d) It cannot be performed with a normal type of check valve.
   e) It is used whenever the mud motor and bit are run.

32. How is the pipe ram on the quad BOP tested?
   a) Ram must be tested from below using the Kill wing valve.
   b) Ram must be tested by using the kill connection on the quad BOP.
   c) Ram must be tested by pumping mud through the coil.
   d) Ram must be tested before rigging up by using a straight bar.
33. Listed below are several advantages of coiled tubing units over other types of workover units. Which is considered the most advantageous?

   a) No tubing connections to make or break.
   b) Less manpower requirements.
   c) Tubing costs less per foot than joined pipe.
   d) Ability to circulate while running in and out of hole.

34. Listed below are several disadvantages of coiled tubing units compared to other types of workover units. Which is considered the most disadvantageous?

   a) Tubing size is limited.
   b) Inability to rotate tubing.
   c) Only suitable for relatively light drilling.
   d) Limited circulating rates.

35. How is coiled tubing run in and out of the well?

   a) Spooled on and off a reel using hydraulic power.
   b) Raised and lower with an arrangement of sheaves supported by a telescoping gin pole.
   c) The coil is moved up and down the hole by an injector/extractor.
   d) Skates are fitted onto the reel to supply gripping friction.

36. The first elastic limits of the tubing are exceeded when it is first coiled on to the reel?

   a) True.
   b) False.

37. The device that guides and distributes tubing on to the reel is called?

   a) The over wind mechanism.
   b) The level wind mechanism.
   c) The level override mechanism.
   d) The gooseneck guide frame.
38. Coiled tubing has?
   a) Lower tension limits than conventional tubing.
   b) Lower compressive limits than conventional tubing.
   c) Lower collapse limits than conventional tubing.
   d) All of the above.

39. The tubing stripper on a coiled tubing unit is often referred to as?
   a) The annular.
   b) The pack-off tool.
   c) The stuffing box.
   d) None of the above.

40. All stripper assemblies for coiled tubing units are well bore energised?
   a) True
   b) False

41. The Quad ram set is in common use on coiled tubing jobs. What is the recommended arrangement (from top to bottom)?
   a) Pipe, Slip, Cutter, Blind.
   b) Blind, cutter, Slip, Pipe.
   c) Blind, Flow Tee, Cutter, Slip.
   d) Slip, Pipe, Cutter, Blind.

42. Two of the advantages of using coiled tubing for remedial work is the ability to work on live wells and the ability to circulate going in or out of the hole. What disadvantage can be associated with these advantages?
   a) Pressure limits due to BOP equipment.
   b) High volume, low pressure pumps on the unit.
   c) The injector/extractor may not be able to overcome well pressure.
   d) Relatively low pumping rates due to the high friction created when pumping through a small diameter tubing.
### Answer Key: Coiled tubing

1.  
   \[ a = 6 \]  
   \[ b = 3 \]  
   \[ c = 4 \]  
   \[ d = 2 \]  
   \[ e = 1 \]  
   \[ f = 5 \]  
   11.  
      \[ a \]  
      \[ a \] & \[ c \]  
   29.  
      \[ c \]  

2.  
   \[ a = 1 \]  
   \[ b = 3 \]  
   \[ c = 2 \]  
   16.  
      \[ a \]  
   34.  
      \[ b \]  

3.  
   \[ d \]  
   19.  
      \[ c \]  
   37.  
      \[ b \]  

4.  
   \[ a \]  
   20.  
      \[ c \]  
   38.  
      \[ d \]  

5.  
   \[ a \]  
   21.  
      \[ a \]  
   39.  
      \[ c \]  

6.  
   \[ b \]  
   22.  
      \[ b \]  
   40.  
      \[ b \]  

7.  
   \[ b \]  
   23.  
      \[ b \]  
   41.  
      \[ b \]  

8.  
   \[ c \]  
   24.  
      \[ a = 4 \]  
   42.  
      \[ d \]  

9.  
   \[ a = 3 \]  
   \[ b = 5 \]  
   \[ c = 4 \]  
   \[ d = 2 \]  
   \[ e = 1 \]  
   \[ f = 3 \]  

10.  
    \[ a = 4 \]  
    \[ b = 2 \]  
    \[ c = 6 \]  
    \[ d = 1 \]  
    \[ e = 3 \]  
    \[ f = 5 \]  
    25.  
    \[ e \]  
    26.  
    \[ d \]  
    27.  
    \[ c \]  
    28.  
    \[ b \]
CHAPTER 5

SNUBBING
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1. INTRODUCTION

1.1 General

Snubbing, known literally as “pressure tubing” in Norwegian, is an intervention method for working in live wells on fixed platforms. Snubbing is also called “heavy intervention”, as the weight of the snubbing stack may approach 100 tonnes, and rigging up and unrigging the equipment is a labour-intensive task. Snubbing is not utilised on floaters because of its size (the equipment needs room in the drilling tower between the drill-floor and the drill).

When running into or pulling out of the well, single tubing is utilised.

The well pressure is controlled by means of a stripper rubber, which presses round the pipe from the outside. The stripper rubber is located in the stripper bowl, which is an integral part of the snubbing stack. Inside the pipe/workover string are two back-pressure valves (BPVs) which keep the well pressure under control.

To enter the well we need a force that is greater than the well pressure multiplied by the area of the workover string. This force will lessen as we run further into the well, because of the weight of the pipe that has been run into the well. We employ the concept of “pipe-light” of this first phase of running in.

Stripping (or “pipe-heavy” condition) is the term used when the weight of the workover string is higher than the well pressure which is trying to squeeze the workover string out of the well.

Rigging up is a relatively rapid process, thanks to the modular design of the equipment. On an offshore platform, rigging up takes about four days, while unrigging can be done in about three days.

When we are working under pressure we must be able to trust our equipment 100%, which in turn makes certain demands of back-up equipment. If parts of the system need to be replaced or maintained during the operation, a reserve or back-up system must be capable of being connected up in order to maintain barriers and safety margins.

Snubbing equipment can be rigged up on top of existing BOPs, casing, tubing, drill-pipes or Xmas trees.
1.2 Tasks requiring snubbing

Typical snubbing tasks include:

- Fishing or internal milling in tubing or the casing
- Washing out scale in the liner and inside the gravel packing
- Drilling through cement or bridge plugs
- Washing out fracture material
- Pressure control/well killing
- Circulating out heavy drilling mud or fluids
- Running in and retrievable plugs
- Acid treatment and washing
- Nitrogen pumping, when depth and pressure are too high for coiled tubing
- Completion operations
- Gravel packing
- Squeeze cementing/back plugging.
2. PRESSURE-CONTROL IN EQUIPMENT

Snubbing is basically employed when working under pressure. Equipment used to control pressure includes:

- Stripper rubber
- Two stripper ram units
- Equalizing loops and vent lines
- Safety rams
- Blind ram or blind/shear ram
- Choke and kill system.

The primary barrier is the stripper rubber, two stripper rams and the equalization system. As an alternative, we can install an annular preventer as an extra security element in the primary barrier. Two flapper valves or check valves are used internally in the workover string.

The secondary barrier consists of safety rams. Two safety rams, a combined blind/shear ram and an annular preventer are normally employed. Nipple profiles are installed inside the string. If both check valves begin to leak, plugs for installation in the nipple profiles can be pumped down.

The tertiary barrier is a safety head which consists of a shear/seal BOP and riser located as close as possible to the Xmas tree/wellhead. This shear/seal must be capable of being operated independently of the other valves in the stack. See Figure 1.

Reserve/back-up equipment must always be available in case of failure of the primary equipment. If this should happen the operation must be halted and the reserve equipment must be connected up and utilised until the primary system has been repaired.
Figure 1: Barrier philosophy
Stripper rubber

A stripper rubber is shown in Figures 2 and 3. The stripper rubber consists of a steel-reinforced rubber packoff unit which seals around the workover string when this is being run into or out of the well. The well pressure helps to maintain the seal between the packoff unit and the string. There also exist designs for stripper rubbers that utilise hydraulic pressure to pre-tension the packoff unit against the string.

The stripper rubber is located under the lowest part of the jack in the window area, and it is utilised to run the string in and out if the well pressure and the string permit this to be done. This is an efficient operational method, as we do not have to open the element when tool-joints, for example, are passing. The maximum well pressure under which stripper rubbers can be employed is about 3000 psi, although their useful life is severely limited at well pressures above 1500 psi. It is normal to replace packoff units several times in the course of a round trip of the workover string. Wear is evident by ever-increasing leakages past the packoff unit.

If the well pressure is so high that we have to strip in or out of the well, the stripper rams act as the primary barrier and the safety ram as the secondary barrier.

Note! When stripping (i.e. using stripper rams) it is important not to allow pressure to build up between the stripper rams and the stripper rubber. This can be prevented either by removing the packoff unit, the needle valve or the bull plug below the stripper rubber.

Figure 2: Stripper rubber housing (bowl) with needle valve
Stripper rams

These two valves are located below the stripper rubber and are conventional ram-type BOPs. The uppermost is called stripper 1 and the lower, stripper 2. (see Figure 4). These valves are utilised when we cannot use a stripper rubber, either due to high well pressure or because the shape or size of the tools or tool-joints do not permit the passage of a stripper rubber.

The valves are closed during the stripping process. In order to increase the lifetime of the valves a special type of hard rubber insert is used in the rams. (See Figures 5 and 6).
Figure 4: Names of stripper ram components
Figure 5: Bowen snubbing (stripping) BOP
Equalizing loop and vent line

When we trip using the workover string and use a stripper ram it is necessary to utilise a pipework equalizing loop between the lower side of stripper 1 and the lower side of stripper 2. A hydraulically actuated valve is mounted on this pipe. The equalizing loop is employed to equalize the pressure across stripper 2 before it is opened. A fixed choke is placed in the line in order to avoid pressure hammer during the equalization process.

A vent line from the underside of stripper 1 is used to bleed off pressure between stripper 1 and stripper 2 before stripper 1 is opened. This line is normally equipped with two valves; an internal manual valve and an external hydraulically actuated valve. The line leads to a closed outlet ?? on the platform or elsewhere where the well fluids are collected or burned off. In high-pressure wells it is also normal to utilise the fixed choke to damp down pressure hammer and reduce the amount of wear on the valves in the line.

A riser spool is also inserted between stripper 1 and stripper 2 in order to make room for tool joints and tools that are to be run in or out of the well.
Figure 7: Sequence of operations when sluicing in a tool joint, for example
Safety rams

These are positioned below the stripper rams. The function of safety rams is to maintain well pressure if the stripper rams should leak, and while a stripper ram is being replaced. The designation “safety ram” is due to the fact that the valve functions as a reserve/back-up valve for the stripper rams. There should be a safety ram for each dimension of workover string, i.e. if we enter the well with a tapered string we must have two safety rams in the BOP configuration.
Figure 8: Cameron U-BOP safety ram
Blind ram/blind shear ram

Blind rams close and seal of the well-flow. Shear rams cut the workover string and close the well-flow. Blind shear rams both cut and seal the well-flow.

For the sake of redundancy two sets of valves capable of shutting the well should be installed below the safety rams. When we are rigged up on top of a Xmas tree, the tree has valves that can be closed, i.e. we then need one set of blind rams or blind shear rams.

A blind shear ram is utilised to enable us to cut the string in an emergency. It is therefore necessary to be sure that the valve is actually capable of cutting the workover string in use; the dimensions and grade of materials employed are important factors.

The control handle for the shear ram must be covered, so that a two-stage operation must be put into effect to trigger the valve. The shear ram s usually operated from the control panel on the drill-floor ??, and that qualified personnel continually keep and eye on the panel during snubbing operations.

Choke and kill lines

Outlet spools and access points are required to be able to pump into and accept backflow from the well. All arrangements of this sort must have double sets of valves, and outlets that are not in use must be blind flanged.

The outer valve should be used in operations. If this valve requires maintenance or replacement, the inner valve is used as the barrier.

There must always be at least one pipe ram preventer below the choke line.

The choke is an integral part of the well control system. If we lack the possibility to pump into or flow back from the well, we do not have control of the well.

The choke manifold with choke(s) is normally located on the drill-floor in the immediate vicinity of the well or rig-up. We can also rig the choke directly on the outlet spool.
2.2 BOP control system

The BOP control system supplies the hydraulic fluid that is needed to operate the BOPs. The hydraulic system can be divided into two separate systems on the basis of the power pack which is the primary source of hydraulic fluid. If the power pack should fail, an accumulator system is required.

The accumulator system must have at least 150% volume capacity to close, open and close again on the BOPs that have been rigged.

Example 1:

A snubbing stack consists of 6 x Hydril 4 1/16", 15000 psi snubbing BOPs. What is the volume required of the accumulator system?

Hydraulic volume required to close each ram: 2.43 litres
Hydraulic volume required to open each ram: 2.58 litres

The total volume can now be calculated if we take into account the requirement that it must be 150% of the minimum capacity:

Total volume required = 1.5 x 6 x (2.43 + 2.58 + 2.43) = 66.96 litres

Example 2:

We now wish to calculate the usable volume of fluid in the accumulator bottles.

| Volume of accumulator bottle: | 38 l | (V1) |
| Max. accumulator pressure:   | 206 bar | (P2) |
| Filling pressure:            | 69 bar | (P1) |

Utilising the Gas Law for Isothermal Processes we find the smallest permissible gas volume:

\[ V_2 = P_1 \times V_1/P_2 = 38 \text{ l} \times 69 \text{ bar}/207 \text{ bar} = 12.6 \text{ l} \]

We are using hydraulic fluid. The pressure must be at least 83 bar (P3). The Gas Law is used to find the maximum permitted volume of gas.

\[ V_2 = P_1 \times V_1/P_2 = 38 \text{ l} \times 69 \text{ bar}/87 \text{ bar} = 31.6 \text{ l} \]

The useful volume of the accumulator bottle = V3 - V2 = 19 litres
Example 3:

The number of bottles required is given by:

\[
\text{Total fluid required (Example 1) / useful volume of fluid per bottle (Example 2) = 66.96 l / 19 l = 3.52 bottles; rounded up to 4 bottles.}
\]

2.3 Pressure-control equipment in the string

In order to prevent the well from flowing in via the workover string a minimum of two BPVs are installed at the bottom of the workover string (above the tools if these are at the end of the string). This also allows pumping down the string as the BPVs will open for a pumping pressure that is greater than the well pressure (at the valves). (see Figure 9).

In order to allow for leaks through the BPVs, nipple profiles must be installed above these valves. If a leakage occurs a pump-down plug can be pumped down and installed in the nipple profile. (see Figure 11).

Figure 9: BPVs (Back-Pressure Valves)
Figure 10 ??
2.4 Other pressure-control equipment
As mentioned in the Introduction, snubbing has several applications which in turn make special demands of the stack and the equipment used. Broadly speaking, three sets of conditions need to be taken into consideration:

- The pressure under which the work is to be done
- The tasks involved
- The type of fluid involved.

Pressure conditions

When working at high pressures it is extremely important to use dedicated equipment and to incorporate sufficient redundancy to cover all likely or possible circumstance that might arise. The downside of leakages can include explosions and blowouts.

Pressure-control equipment must be of a pressure class that is higher than the maximum pressure that can be expected to occur in the course of the operation. The also includes the workover string, in which, if a leakage should occur in the BPVs, well pressure can come up to the surface (to the stabbing valve). Working pressures for snubbing BOPs are usually 10,000, 15,000 or 20,000 psi.

When a workover string is being run in we are faced with a classical buckling situation. The well pressure tries to force the string out, and the well pressure as a parameter helps to reinforce the tendency to buckling.

In the vent line below stripper 1, high pressure that is to be bled off will produce pressure hammer in the system and erosion in the hydraulic valve when this is opened. A fixed choke will reduce pressure hammer and erosion; the size of the choke must be chosen on the basis of the type of fluid in use and the amount of pressure to be bled off. It is often natural to install a check valve in the kill line. If the kill line should fail during killing, this will prevent a backflow of fluid past this valve.

If the job to be performed involves extensive use of choke and kill lines, it is often natural to attach these lines to a riser joint rather than to outlets on the ram BOPs. In order to reduce erosion it can be advantageous to protect this riser joint internally with hard metal (e.g. an Inconel coating).

Screwed joints must not be utilised in equaliser loops, bleed-off lines or the choke and kill system. Bolts in flanged connections must be tightened to the moment specified.

Annulars are also used as back-ups for stripper rubbers in certain types of operation. (See Figures 12, 13 and 14).
Figure 12: Wedge-cover single spherical BOP
Figure 13a: Shaffer annular BOP
Figur 13b: Cameron D annular BOP
Figure 14: HydriG GS annular BOP

**Tasks**

In certain operations such as fishing and well-killing an extra strong workover string may be necessary. In such cases we often choose to use two workover strings; a lighter one in the lowest part of the well, which changes to a stronger string in the upper region of the well. This means a double set of safety rams, and the insertion of inserts in stripper rams at the changeover from one string dimension to the other.

Slip ram BOPs are another type of equipment that is used when we wish to stop the string or prevent it from rotating. An alternative slip rams is to use a hanger flange which can be screwed into the string and from which we hang off the weight on top of the stripper rubber.

**Type of fluid**

Hydrogen sulphide may damage equipment, and the risk increases as well pressure rises. It is extremely important to take the type of fluid in use and the possibility of H$_2$S into account during advance planning for the job.
3. SNABBING UNIT EQUIPMENT

As mentioned in the Introduction, snubbing equipment is modularised so that it can easily be transported and rigged up or unrigged. The equipment consists of the following components:

- Hydraulic jack assembly
- Work basket and control panel
- Hydraulic power pack
- Circulation system
- Snubbing BOP stack.

3.1 Hydraulic jack assembly

The main component of the hydraulic jack is the hydraulic cylinders. Various models with two or four cylinders exist. The capacity of the jack is a function of the number and dimensions of the cylinders and of the hydraulic pressure utilised.

The piston rod which leaves the top of each cylinder is attached to a travelling assembly. Hydraulic pressure in the cylinders below the pistons makes the piston rod move upwards, while pressure on the upper surface of the piston forces the piston rod down.

Besides the hydraulic cylinders the jack consists of:

- Travelling slips
- Rotary
- Guide tube
- Stationary slips
- Window and window guide.

Travelling slips are located on the travelling assembly and move vertically when the cylinders move up and down. These hold the workover string and transfer the lifting or snubbing capacity from the jack to the string. The travelling assembly may be fitted with several sets of travelling slips. Each set of slips maintains the force in a single direction, and it is important to make sure that the correct slips are utilised - particularly as we move from a “pipe-light” to a “pipe-heavy” condition. We normally utilise three sets of slips; two of them intended to hold the string in one direction and the third in the opposite direction. If the well pressure is high it may be practical to use two sets of slips for snubbing (i.e. holding the string fast when it is being run into the well); similarly for fishing, when the string may suffer from wear and suddenly change from “pipe-light” to “pipe-heavy”.

Rev.01 Feb 2009
The snubbing unit may be equipped with a rotary as part of the travelling assembly. The rotary is hydraulically operated and its rotation moment is controlled by regulating the hydraulic power, and the rotation speed by controlling the volume of hydraulic fluid supplied by the power pack. It is usual to set limits to the maximum rotation moment in advance in order to avoid the risk of exceeding the maximum make-up moment for the workover string.

The guide tube is installed from the underside of the travelling assembly to the top of the set of stationary slips. Guide tubes provide lateral support for the workover string, and thanks to their telescopic design they support all the travelling slips in all positions. By providing lateral support to the workover string they prevent it from buckling when we are entering the well (“pipe-light”).

The stationary slips hold the workover string in position when the travelling slips are disengaged and the travelling assembly is being moved to a new position in order to take a new grasp of the string. Two sets of stationary slips are normally used.

The window is located in the lower part of the jack, under the stationary slips. The window allows access for replacing the stripper rubber and installing any tools that are longer than the guide tube. The window guide tube provides lateral support for the workover string and it is recommended to install and secure this in all phases of the snubbing operation. (See Figure 15).
Figure 15: Hydraulic snubbing unit
3.2 Work basket

The work basket is located above the jack and is used by the two or three persons who operate the jack, make up the workover string, etc. The basket contains the control panels for the jack, the travelling and stationary slips, BOP and counterbalance winch.

The operator on the basket can run the system pressure up to the previously planned maximum value, thus eliminating the possibility of damaging the workover string or other equipment. Any changes in this pressure must be made using the control panel on the drill-floor.

The work basket is fitted with evacuation routes; either slides or “bridges” to the work deck which lies beside the well.

3.3 Hydraulic power pack

The hydraulic power pack supplies the pressure needed to operate the jack, the BOPs, the rotary, counterbalance winch and the rig-tongs in the work basket. The power pack consists of hydraulic pumps which are driven by a diesel engine.

Snubbing operations employ three different pressures:

- Main system pressure
- BOP operating pressure
- Counterbalance pressure.

The main system pressure is the pressure which is supplied to the jack’s hydraulic cylinders. This pressure has to be regulated in order to prevent excessive power from being applied to the workover string. NB: The relationship between hydraulic power and applied force is different in the snubbing phase and the lifting phase.

BOP operating pressure is supplied to slips, stripper rams and safety rams. This pressure is normally controlled from the work basket. NB: If a shear ram has been installed it is important to control the pressure such that the shear ram is capable of cutting the material it was intended to cut.

Pressure to the counterbalance winch operates the system for picking up and setting down tubing from the work basket. This pressure should be kept as low as possible in order to avoid damage if the tubing should get stuck or is run in too far.
3.4 Circulation system

If we are going to pump down the workover string, such equipment as the swivel, kelly hose and pump must be available. A hose which is also connected to the swivel in the basket is attached to the stack standpipe. When pumping, a valve is installed between the workover string and the swivel.

Pumping through the workover string involves a low rate and high pressure. For this reason, the circulation system must be designed for the maximum pressure expected.

3.5 Snubbing BOP stacks

Various types of snubbing stacks exist. The most common are:

- Hydraulic jack
- Hydraulic long-stroke
- Mechanical conventional.

Hydraulic jack

This is the most commonly used system, due to its compact design, high snubbing force, lifting power and rotation moment, and the fact that it can be used in conjunction with many different types of workover string. The maximum stroke-length of this type of jack is 3 - 4 m.

Hydraulic long-stroke jack

Compared to the hydraulic jack, this version has a higher tripping speed and is more efficient in handling BHA. It can be equipped to run a double stand an has a stroke-length of about 11 m.

Mechanical conventional

This version takes its hydraulic power from the stack’s ?? system. The point of using this type is that it enables the stack to handle pipe in “pipe-light” mode. The advantages of this system are that it requires less equipment, is rigged up more rapidly, and that it can handle all pipe dimensions.
4. OPERATION

Rigging up

When the system is being rigged up the Xmas tree will “see” the weight of the snubbing stack plus transferred forces from the guy wires which provide the stack with lateral support.

We should remember that the Xmas tree/well-head will see the weight of the workover string during the operation, plus any hold-fast forces if the workover string should become stuck. These forces can become so high that they may exceed the capacity of the well (on offshore platforms, buckling of the conductor) and must be kept under control.

During operations, e.g. back-flow, the well-head moves as a result of thermal forces, to the extent that the tension on the guy-wires must be kept an eye on.

Testing

Equipment must always be tested before we enter a well. Low-pressure and high-pressure tests and functional test are carried out in order to check whether valves open and close correctly.

Water mixed with glycol is used for pressure testing. Glycol is used to prevent hydrate formation.

The accumulator system is tested separately from the storage pumps and its valves are tested for close, open, close. This enables us to check whether the accumulator bottles contain the correct volume of fluid.

Following the start of an operation, each pipe ram in the BOP stack must be tested daily. Blind rams and blind/shear rams are tested after each trip out of the well.

The BOP must be tested at least every 14 days.

Snubbing force

When we are running into a well the snubbing force must be equivalent to the force that is trying to push the string out of the well plus the friction between the string and the stripper rubber. The force that is pushing the string out is equal to the well pressure multiplied by the cross-sectional area of the string. Initial snubbing also produces the highest snubbing force. This force may result in buckling of the downhole equipment/workover string. (See Figure 16)

When we are snubbing into the well the weight of the string will gradually compensate for the snubbing force. When we know the weight of the string, the type
of fluid in the well and the well pressure, we can calculate the length of the workover string whose weight will balance the force which is trying to push the string out, i.e. the point of balance.

We do not normally fill the workover string with fluid until we reach the point of balance. At this point we change over to a slip which holds the forces in the opposite direction, before continuing to run in with a "pipe-heavy" string.

![Diagram of Forces on Work String]

**Figure 16:** Forces involved in snubbing
5. CONTINGENCY PROCEDURES

Faults and undesirable events can always occur and it is important to have plans ready for dealing with these. Some faults are common in the sense that they occur frequently; e.g. leaks across stripper rubbers, faults in the stripper ram elastomer and faults in slip dies. Others occur extremely seldom; e.g. faults in packers below the BOP.

We can divide contingency procedures into four categories:

- General
- Faults in topside equipment
- Faults in downhole equipment
- Operator errors.

5.1 General

Planned or deliberate dropping of the workover string - “pipe-heavy”

1. Install the stabbing valve
2. Locate the connector at the level of the work basket and loosen the connection (do not back off)
3. Hang off the string on the slip rams (if this type of BOP is installed) or on stripper 2 or the pipe safety ram
4. Close the stabbing valve and travelling slips
5. Engage the rotary and back off the connection which has already been loosened
6. Pull up 0.5 m to get clear of the workover string
7. Open all the rams below the hang-off ram
8. Open the hang-off ram and the string will drop
9. Close the blind ram and the valves in the Xmas tree

Planned or deliberate dropping of the workover string - “pipe-light”

The decision to drop a workover string must be based on the amount and rate of the leak. The procedure is the same as for the "pipe-heavy" condition, except for backing off the connector. In this case it may be necessary to pump in fluid between stripper 1 and stripper 2 (or via the bleed-off line) in order to equalise the pressure inside the workover string and thus eliminate the snubbing force on the part of the string which is to be dropped.
Planned or deliberate cutting of the workover string

1. Install and close the stabbing valve
2. Close one of the stripper valves
3. Verify that the position of the connector in the workover string is not in conflict with the shear/seal ram
4. Position the travelling head 0.5 m over its lowest position
5. Close both the travelling snub and heavy slips
6. Open stationary slips
7. Close the shear/seal ram
8. Lift up over the uppermost shear/seal ram (if several are installed) and close it
9. Bleed off the pressure over the uppermost shear/seal in order to verify that the valve is tight
10. Close the valves in the Xmas tree in order to confirm that the string has dropped.

Note: We must always use the lowest shear/seal ram (tertiary valve) when cutting the string. This makes it possible to pull up the workover string to above the upper shear/seal BOP (secondary barrier), which can be closed if the lowest shear/seal ram is not tight.

Emergency shut-in

In the course of routine operations, faults related to other operations that are taking place simultaneously may require a rapid response. Examples include leaks in flowline, faults in cranes, gas leaks, oil leaks on the deck.

1. Position the workover string at the same level as the work basket
2. Close the slips (in order to secure the string in both “pipe-heavy” and “pipe-light” conditions, equalise and bleed off the pressure across valves, stripper rams and the safety ram
3. Install the stabbing valve in the string and close it
4. Close the upper safety ram and stripper rams
5. Secure any hanging loads by means of the winch
6. Shut off the power pack
7. Close relevant gate valves in the BOP stack and choke manifold.
5.2 Faults in topside equipment

Power pack breakdown

1. If possible, position the end of the workover string at the same level as the work basket
2. Close both stationary and travelling slips
3. Close the (uppermost) safety ram
4. Install the stabbing valve in open position
5. Close both stripper rams

Faults in slips

The slips must be continually inspected when in use as they form part of the well-control system. In some cases, deposits of scale from the well can build up round the slip segments quite rapidly, reducing the ability of the slips to grip the workover string.

1. Immediately close the reserve slips
2. Close a stripper ram
3. Install a stabbing valve in open position
4. Repair, clean or replace slips. Overhaul the slip bowl if necessary
5. Test the load-bearing capacity of the slip bowl by transferring a load with the snubbing jack (with stripper ram closed)
6. Inspect the other slip bowl for similar problems.

Faults in stripper rubbers

Stripper rubbers suffer wear in use, and the degree of wear will be a function of time of use, type and quality of the rubber, the surface state of the workover string, well pressure and the fluid in the well.

Leaks in stripper rubbers can produce fluctuations in well pressure. In such cases, the travelling slips must be closed until the pressure stabilises.

1. Close stripper 2 and the travelling slips
2. Position the end of the workover string at the same level as the work basket
3. Install a stabbing valve in open position
4. Stabilise the well pressure
5. In “pipe-heavy” condition: replace the stripper rubber
   In “pipe-light” condition, running into hole: strip into the well until the workover string is “heavy” then replace the stripper rubber
   In “pipe-light” condition, pulling out of hole: continue to run out by means of “ram to ram” stripping.
A stripper rubber can be replaced in “pipe-light” condition, although this procedure is not recommended. In such cases we must be sure that all the pressure below the stripper rubber has been vented and that this “space” remains vented until the maintenance operation has been completed.

**Leakage in stripper ram**

Leakages can occur in stripper rams, and it also happens that both units leak simultaneously (normally the lower ram, stripper 2, suffers most wear).

1. Close the stripper ram which is tight and close the travelling slips
2. If the leak has stopped, position the end of the workover string at the same level as the work basket
3. If the leak has not stopped, close the upper safety ram
4. Install a stabbing valve in open position
5. Stabilise the well pressure
6. Bleed off the pressure above and below the leaking stripper ram
7. Open the stripper ram
8. Replace elastomers as required
9. Close the stripper ram
10. Equalise the pressure across the BOP that is maintaining the well pressure and below the repaired stripper BOP
11. Check for leaks above, below and around the bonnet packer on the repaired stripper ram
12. Open the safety ram and continue the operation.

**Leak in safety ram**

The upper safety ram should always be used. If this is leaking, do the following:

1. Close the next safety ram
2. Bleed off the pressure
3. Repair the leaking safety ram.

If both safety rams are leaking, do the following:

1. Close the annular BOP (if installed)
2. Position the string in such a way that there is no connection within the BOP ram
3. Verify the integrity of the BOP’s closure system.

Discuss other measures such as killing the well, pulling out, dropping the string into the hole, cutting the string.
Leak in blind ram

Here we assume that we have pulled out of the well and got the BHA into the BOP stack. The next step will be to close the blind ram so that we can lubricate out the BHA. At this point we find that the blind ram is leaking. We then have the following alternative rams to lubricate against:

the valves in the Xmas tree
the DHSV
we can go into the well again with the BHA and kill it
we can go into the well with the ?? - install this.

If the BOP stack includes a blind ram below the leaking blind ram, the following actions can be taken:

1. Go in with the workover string
2. Close the lower pipe ram
3. Bleed of the pressure above
4. Open and repair the blind ram.

If the BOP does not have a pipe ram below the leaky blind ram but does have sufficient lubrication height over the BHA blind ram, and if another set of blind or blind/shear rams is available, the procedure is as follows:

1. Install the BOP in the string
2. Run in the workover string
3. Close the lowermost pipe ram
4. Bleed off above
5. Open the bonnet on the nearest ram BOP above the BOP that is maintaining the pressure, and replace the rams ?? on the slip ram
6. Hang off the workover string from the slip rams and break the connection at the slip joint
7. Unrig the snubbing equipment and reconfigure the system so that we have sufficient lubrication height to be able to retrieve the BHA by installing a new shear/blind ram.

External leaks in the tertiary well-control system (safety head)

In such cases, the well is out of control. Our choice of further measures must be based on conditions such as:

- leakage rate
- gas content
- weight of snubbing string and snubbing power
- position of the BHA relative to the DHSV, well depth and type of surface equipment.
Potential further measures may be to:

- Pump kill fluid (bullhead, circulate fluid, run into the well to an acceptable depth and pump kill fluid)
- Pull out to above the DHSV (if possible) and close the DHSV
- Drop the workover string
- Cut the workover string.

External leakage with wireline passing through the snubbing stack

Snubbing shear rams will be able to cut the wireline, and wireline shear rams can also be installed as part of the snubbing stack.

Faulty choke

This typically happens in the course of long washing operations. It can be due to long washouts, a break in the line from the BOP stack or line blockage due to hydrates.

1. Pull out a few metres from the bottom
2. Isolate the faulty valve
3. Circulate through the reserve choke and/or line
4. Repair the choke and/or line
5. Continue the operation via the primary choke or line.

Internal blow-out

In the case of an internal blow-out as as result of a workover string breaking, a faulty stabbing valve, etc., the following procedure may be relevant:

1. Position the end of the workover string at the same level as the work basket
2. Close the travelling slips
3. Close a stripper valve and install and close a stabbing valve.

If it is impossible to install the stabbing valve, consider taking the following steps:

4. Cut the workover string
5. Drop the workover string
6. Secure the workover string in the stack.
If the BOP is fitted with a pipe ram below the shear ram, the following steps can be taken:

7. Select a connection and break it, but do not screw it in // out all the way
8. Hang the workover string from a pipe ram below the blind ram. If the string is “light”, we must utilise a slip ram (which is also located below the blind ram)
9. Check that the travelling slips are set on the the landing tubing. Engage the rotary and back off the landing pipe
10. Pull out the pipe to above the blind ram
11. Close the blind ram and the blow-out
12. Install and close the stabbing valve on top of the new landing pipe
13. Position the landing tubing in the BOP stack above the blind ram, close a stripper ram and equalise the pressure
14. Open the blind ram
15. Screw in the workover string under pressure, using the landing tubing. Skirted tubing may be necessary for good centralisation
16. Continue the operation.

5.3 Faulty downhole equipment

Check valves or back-pressure valves are a type of well-control equipment that is located inside the string in order to prevent the inflow of hydrocarbons. Two such valves are normally installed. After a long period of pumping they may leak, and nipple profiles are therefore installed in the string above the BPVs. Plugs can be installed in these profiles.

If fluids begin to emerge from the workover string and there is no change in the weight of the string, it is probably the BPVs that are leaking. The following procedure is recommended:

1. Position the end of the workover string at the same level as the work basket. If possible, screw in the stabbing valve in open position and close it
2. Check the weight of the string
3. Connect the circulation pipe to the stabbing valve
4. Open the stabbing valve. Pump and bleed back several times in order to remove dirt in the BPVs. Compare pumping pressure and rate with previous pressures and rates.
5. Position the workover string in such a way that you can visually check the last connection made up in the window. Check for leaks. If there are no leaks, reposition the workover string with its end at the level of the work basket.
6. Run a plug into the well (via wireline or pumping). Bleed off the pressure in order to verify the plug is in position. If there is still a leak, continue with a second plug. If this still leaks, we must consider other measures such as bridge plugs, killing or cementing; see other fault modes.
Leaks following installation of wireline plugs

Three nipple profiles are normally installed above the BPVs. If we still lack control of the leak from the workover string after installing three plugs, we can continue using the following procedure:

1. Pull the faulty plugs. Displace the string until the fluids run clear. Re-install the plug(s)
2. If this does not resolve the problem, consider the possibility that a connection may have been washed out
3. Install a permanent bridge plug with the aid of an electric wireline (with installed flapper)
4. Kill the well?

Lost part of workover string

There can be several reasons for a string breaking: a washed out connector, damaged tubing, mechanical external wear (e.g. from a milling operation), capacity of the string exceeded. Fault-seeking is dependent on wireline. If we do not wish to kill the well we can try the following:

1. Install and close the stabbing valve (if this has not already been done)
2. Close the travelling slips
3. Close the stripper ram
4. Rig up an electric wireline. Run it into the well and check where it ends, if necessary ?? by means of ?? concentric tubing. Install two bridge plugs in the lowermost tubing.
5. Bleed off the pressure in the workover string and unrig the electric wireline.
6. Pull out of the hole.

Washed-out connection

If we conclude that a connection can have been washed out we can consider taking the following steps:

1. Use a wireline to estimate the depth and size of the washout
2. Pump down kill fluid, packing material or other pills that can alleviate the problem
3. If it is impossible or undesirable to kill the well, the following steps may be considered:
   a) Install a straddle packer over the hole
   b) Install a bridge plug over the hole
   c) Pull the string until the hole in the string is located between the strippers
   d) Close the lower stripper (no. 2)
   e) Bleed off the internal string pressure to zero (as long as the BPVs are tight)
   f) Pull the connection with the washout
   g) Replace damaged tubing and continue operation.
5.4 Human error

Human error is the major cause of faults. The following sections discusses two such errors, and how to correct them:

Accidental closing of blind ram

If we close the wring ram the workover string may collapse or part.

1. Close the travelling slips immediately, install the stabbing valve, close the slip ram if this has been installed and close both stripper BOPs
2. Alternatively, we can lift up the string sufficiently to close the pipe ram above the ram which was accidentally closed, in order to isolate the damaged part of the string from the well. ??

Accidental loss of string down well

This can happen if an interlock system that makes it impossible to disconnect all the slips at the same time has been disconnected.

1. Close the blind ram in order to stop flow-out and shut in the well pressure
2. Close the swab valve on the Xmas tree
3. Fish up the lost string.
6. **SNUBBING: Test Questions**

1. The tool-string is in the well and a leak is discovered in the upper stripper BOP. What is the first action that should be taken to repair the leak?  
   2 points
   
   a) Kill the well  
   b) Close a blind/shear BOP  
   c) Close the lower stripper BOP and a pipe ram BOP  
   d) Close the shear/seal BOP.

2. A leak occurs in the tool-string that has been run into the well. What is the first action that should be taken?  
   2 points
   
   a) Rig a circulation hose and pump killing fluid down the tool-string  
   b) Pump killing fluid into the well through the Xmas tree  
   c) Install a stabbing safety valve on the tool-string and close it.  
   d) Drop a secondary wireline check valve in the tool-string.

3. What is the purpose of the bleed-off line?  
   2 points
   
   a) It is used in emergencies to bring the well-flow to the completion tanks if the BOP system fails.  
   b) It is used to control the pumping rate (bullheading) during a well kill operation.  
   c) It is used to bleed down down the pressure between the stripping rams when the tool-string is being run into or out of the well.  
   d) It is used to equalise the pressure across the lower stripper BOP with the aid of another well before the BOP is opened.

4. What is the purpose of the fluid pump that is normally used in snubbing operations. (select two answers)  
   2 points
   
   a) It is used in well-kill operations.  
   b) It is used to equalise the well pressure across the lower stripper BOP  
   c) It is used to maintain shut-off pressure on the stripping rams.
d) It is used to fill up the tool string.

5. Classify the following BOPs as primary, secondary and tertiary barriers. Put an “X” in one of the boxes for each type of BOP.

<table>
<thead>
<tr>
<th></th>
<th>Primary (1)</th>
<th>Secondary (2)</th>
<th>Tertiary (3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) Pipe/safety ram</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b) Stripping rams</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>c) Shear/seal rams</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>d) Stripper rubber</td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

1 point per correct answer

6. Which of the following statements is correct?

3 points

a) The equalising loop is connected above the top stripping BOP and below the bottom stripper BOP.

b) The equalising loop is connected below the top stripping BOP and above the lower stripper BOP.

c) The equalising loop is connected above the top stripping BOP and above the lower stripper BOP.

d) The equalising loop is connected below the top stripping BOP and below the lower stripper BOP.

7. The nipple profile for the pump-down plug is located in the string under the check/back-pressure valves.

1 point

a) Correct.

b) Wrong.

8. The stripper rubber must be activated by means of a hand pump before it forms a seal around the tool-string.

1 point

a) Correct.

b) Wrong.
9. Why is the safety head Bop installed directly above the Xmas tree?
   2 points
   a) In order to act as a safety ram if the blind shear ram fails.
   b) In order to ensure that the well can be shut-in at the Xmas tree after the tool-string has been cut.
   c) In order to act as a safety ram if the Xmas tree is not capable of cutting the tool-string.

10. Which of the following types of equipment can be repaired with the tool-string in the well?
    (two answers)  3 points
    a) A worn out stripper that is leaking.
    b) A worn out top stripper ram that does not maintain a seal when it is closed.
    c) A worn out pipe ram that does not maintain a seal around a tool-string when it is closed.
    d) A worn out blind ram that does not maintain a seal when it is closed.

11. Which factors have the most influence on the depth of the balance when the tool-string is run into the hole?
    (three answers)  3 points
    a) Well head pressure.
    b) Speed of running in the tool-string.
    c) Fluid in the tool-string.
    d) Snubbing pressure used.
    e) Weight of the tool-string.
    f) Size of stripper rubber.

12. Where should the shear/seal safety BOP be located in the rig up?
    2 points
    a) Directly below the stripper rubber.
    b) Directly below the stripping ram.
    c) Directly above the pipe/safety ram.
    d) Directly above the Xmas tree/wellhead.
    e) It doesn’t matter where it is located.
13. Why is an annular BOP utilised?
   
   2 points
   
   a) In place of a rubber stripper.
   b) As a back-up for the stripping rams.
   c) To seal off all the components of the downhole string irrespective of their outer diameter.
   d) As a secondary valve to the blind ram.

14. A pump down plug is dropped on to the tool-string. Can the string be pulled from the well before work can continue?
   
   1 point
   
   a) Yes.
   b) No.

15. A 2 3/8” workover string is to be run into the hole in order to wash sand out of the well. The snubbing unit has been rigged on top of the Xmas tree. The Xmas tree pressure (SIWHP) is 240 bar. Will it be possible to pump fluid through the workover string with return via the wing valve?
   
   1 point
   
   a) Yes.
   b) No.
16. The snubbing unit shown in the figure has been rigged on top of the Xmas tree. Can a workover string with 1500 m 2 7/8” tubing and 3000 m 3 ½” tubing be run into the well?

1 point

17. A workover string with 2 3/8” tubing has been run into the well to wash out sand. Because of a restriction in the tail pipe it is necessary to retrieve the workover string in order to run 300 m 1.9” tubing below the 2 3/8” pipe section.

Given the rig-up shown in Figure WD 1(Question 16), which of the following statements is correct?

a) Yes.

b) No.
a) A new set of stripping rams for 1.9” tubing must be rigged.
b) A stripping ram blocker for 1.9” tubing must be installed in the lower stripping BOP.
c) An extra Pipe/safety BOP for 1.9” tubing must be rigged.
d) No changes are required in the rig-up.

18. After rigging and functional testing, the topside equipment has to be pressure tested. Which of the following statements best describes how the back-pressure valves in the downhole string should be tested? (Two answers) 3 points
   a) Pump down the workover string with the safety/pipe rams closed.
   b) Install a closed TIW valve on top of the workover string.
   c) Test the back pressure valves by pumping in via the kill line.
   d) Hold the workover string in the slips in order to prevent the tubing from moving up or down.
   e) Hold the workover string so that it does not fall down on top of the swab valve.

19. The workover string has been run into the well. Can the safety pipe ram inner seals be replaced if the stripping rams are closed? 1 point
   a) Yes.
   b) No.

20. Which of the following statements are correct when a bleed-off line has a built-in choke? 2 points
   a) The choke is usually adjustable
   b) The choke is usually fitted with a fixed-size orifice.
   c) The choke is hydraulically actuated from the basket
   d) The choke and the bleed-off line are used to kill the well
   e) The choke is opened only when a tubing connector is run through the annulus safety valve.
21. Which of the following test pressures is used by the manufacturer to test a new BOP of pressure class 690 bar (10,000 psi)?  

2 points

a) 1035 bar (15000 psi).
b) 690 bar (10000 psi).
c) 1380 bar (20000 psi).
d) 1207 bar (17500 psi).

22. What is the purpose of a Blind/shear ram?  

2 points

a) To cut the workover string and simultaneously seal the tubing.
b) To cut the work workover string without sealing.
c) To seal around the workover string in the well.
23. Some of the components in the figure below are numbered. Identify the components by marking the boxes with the correct number in the drawing.

1 point for each correct answer

![Diagram of components in a figure]

- a) Lower ram assembly
- b) Blade packer
- c) Top seal
- d) Upper ram body
- e) Side packer
- f) Upper ram assembly

24. Which type of gas is used to pre-charge accumulator bottles?

2 points

- a) Air.
- b) Nitrogen.
- c) Oxygen.
- d) Carbon dioxide.
25. Some of the components in the figure below are numbered. Identify the components by marking the boxes with the correct number in the drawing.

1 point for each correct answer

[Diagram of a mechanical component with numbered parts]

- [ ] a) Opening chamber cover
- [ ] b) Closing chamber port
- [ ] c) Valve body
- [ ] d) Pack-off unit
- [ ] e) Piston indicator port
- [ ] f) Head
26. During a snubbing operation the surface equipment is seen to be leaking from the connection between the spool and the stripping ram. Which secondary barrier must be closed to make the well safe and to repair the leak?

   a) Annular BOP.
   b) Swab valve.
   c) Upper master valve.
   d) DHSV.
   e) Safety ram.

27. A snubbing unit is being operated on a live producing well. Suddenly, there is a small flow coming up and out of the workstring. The gray valve is installed. After investigation it is found the leak is downhole, above the BHA. Which of the following actions should allow the workstring to be pulled out of hole safely? (two answers)

   a) Continue pulling since it is a small leak.
   b) Kill the well.
   c) Drop the pump down plug and seat it in the nipple.
   d) Set a wireline bridge plug half a joint above the leak.
   e) Pull out of hole but use a stripper ram instead of a stripper rubber.

28. Is it normal practice to change out a worn annular packing element during a job?

   a) Yes
   b) No

29. Is it normal practice to change out worn stripper ram inner seals during well intervention?

   a) Yes
   b) No
30. A well intervention is planned to wash out sand in a well which has SITHP 241 bar (3,500 psi). The snubbing unit will be designed for this operation. What will be the primary barrier of this snubbing unit?

   a) Stripper rubber
   b) Stripper rams.
   c) Annular BOP.
   d) Safety rams.

31. A snubbing unit has remotely operated valves on the bleed-off line and equalising loop. Also some valves on the kill line and choke line are remotely operated. From which location are these valves controlled or activated?

   a) BOP control unit.
   b) Control console in the work basket.
   c) Remote control room.
   d) BOP stack.

32. The snubbing unit has valves on the bleed-off line and equalising loop line which are operated by both remote and manual control. On which side of these valves should a manual operated valve be positioned?

   a) Inside the remotely operated valve?
   b) On either side of the remotely operated valve, doesn’t really matter.
   c) There is no need for a manually operated valve since the control system is in the basket.
   d) Outside the remotely operated valve.

33. What is meant by the term “pipe light”?

   a) The pipe is dry, not filled with mud.
   b) The well is exerting an upward force greater than the weight of the string at a given depth.
   c) The term refers to a range of pipe.
   d) The well is exerting an upward force less than the weight of the pipe.
34. Which type of snubbing unit is most commonly used today?
   a) Conventional units.
   b) Long stroke units.
   c) Hydraulic jack units.
   d) Mechanical units.

35. What is the function of the tubing guide on a snubbing unit?
   a) Prevent pipe buckling
   b) Guide the pipe through the BOPs
   c) Guide the jack pistons into the cylinders.
   d) Guide the safety pipe through the window.

36. The stripper rubber located at the base of the jack is usually;
   a) A low pressure preventer (less than 207 bar).
   b) A high pressure preventer (greater than 207 bar).
   c) A modified ram preventer.
   d) Is used for drilling only.

37. A definition of stripping might be: moving pipe into or out of a well when wellbore pressure is less than the weight of the pipe?
   a) True
   b) False

38. The most crucial part of any operation is?
   a) Anticipated formation pressure.
   b) Condition of equipment.
   c) Careful pre-job planning.
   d) Production.
39. If the slips are set on a tool joint while operating in “pipe light” mode, the following may occur?
   a) The work string may drop into the well.
   b) The work string may part just below the slips.
   c) The pipe could be forced out of the well.
   d) The work string may part just above the slips.

40. Elastic buckling is defined as buckling which does not exceed the yield strength of the pipe and the pipe is not permanently deformed?
   a) True
   b) False

41. On rigging up the BOP control unit (accumulator unit), after connecting hydraulic control lines to the BOPs, what should be the next action taken?
   a) Pre-charge the accumulator with nitrogen gas.
   b) Function test all items.
   c) Place all rams in a block position too charge up the hoses.
   d) Install the injection head.

42. While running the work string into the hole using the stripping rams as the primary barrier, it is found that one of the stripping rams is badly worn and no longer holds pressure. What should be the correct course of action?
   a) Finish the job using only one good stripping ram.
   b) Stop and redress both stripping rams.
   c) Stop and redress the worn stripping ram.
   d) Continue the job because the annular preventer can be used as a primary barrier.

43. Will all the hydraulic fluid inside the accumulator bottles be used to function the BOPs?
   a) Yes
   b) No
44. Is it common practice to change the stripper rams during snubbing operations?
   
   a) Yes  
   b) No 

45. Why is a one gallon accumulator bottle, sometimes hooked up to the closing line on a snubbing annular preventer? (two answers)
   
   a) To stop over pressure on the closing line when stripping through the annular.  
   b) Provide extra usable fluid for stripping operations.  
   c) Quick delivery of fluid.  
   d) Provide backup fluid in case accumulator unit fails.
Answer key: Snubbing Questions

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