

## Chapter 2

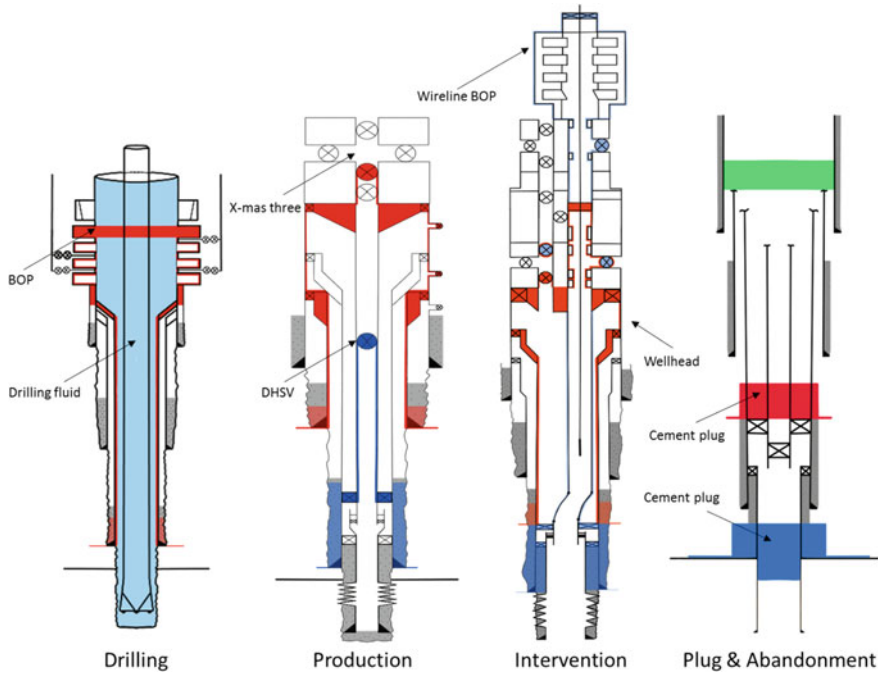
# General Principles of Well Barriers



The principle of well integrity is primarily occurred with maintaining well control with sufficient barriers. *Well integrity* is defined as “*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the lifecycle of a well*” [1]. To control the well, two qualified independent well barrier envelopes should be present at each stage of a well’s life. The petroleum industry has employed the principle of a two-barrier philosophy since 1920s [2]. Generally speaking, the overbalance from the drilling fluid is the primary barrier and the blowout preventer (BOP) with casing string comprise the secondary barrier during well construction. Over time, the petroleum industry has entered into more complex and challenging environments, and therefore, the need to clarify and standardize the well barrier integrity has been increasing. In practice, the application of the well barrier philosophy is more complicate due to technical and operational limitations. Figure 2.1 illustrates the two-barrier philosophy of a well throughout its lifecycle, and Table 2.1 presents examples of barrier systems through its lifecycle of the given well.

### 2.1 Well Annuli

An annulus is any void space between two strings, or a string of casing and formation. When a well is completed, different annuli might be distinguished. In well engineering, the annular space between production tubing and production casing is called *A-annulus*. The annular space between production casing and intermediate casing is called *B-annulus*. The naming procedure is continued until the last annular space, which is between the conductor and formation (see Fig. 2.2) [1]. Generally, these annuli should not have any connection to wellbore fluids. But the annuli are filled with completion fluid or drilling fluid for protection of steel and maintaining the pressure to ensure the integrity of the strings [3].



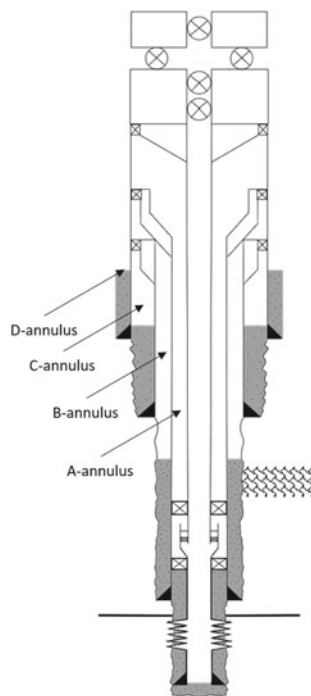
**Fig. 2.1** Illustration of the two-barrier philosophy throughout a well’s lifecycle [2]

**Table 2.1** Examples of barrier systems through the lifecycle of the well given in Fig. 2.1

Example	Primary Barrier	Secondary Barrier
Drilling	Overbalanced mud with filter cake	Casing cement, casing, wellhead, and BOP
Production	Casing cement, casing, packer, tubing, and DHSV (Downhole Safety Valve)	Casing cement, casing, wellhead, tubing hanger, and Christmas tree
Intervention	Casing cement, casing, deep-set plug, and overbalanced mud	Casing cement, casing, wellhead, and BOP
Plug & Abandonment	Casing cement, casing, and cement plug	Casing cement, casing, and cement plug

During coiled tubing well intervention operations, the annular space between the coiled and production tubing should be considered as an annulus and distinguished with a name.

**Fig. 2.2** Distinguished annuli in a completed well



## 2.2 Well Barrier Envelope

### 2.2.1 Primary and Secondary Well Barriers

To understand the subject of well barrier philosophy, it might be beneficial to start with the following question: What is a barrier? The word barrier has its roots from Middle French barrier, which can be traced back to Anglo-French, from barre bar, in 14th century. Merriam-Webster dictionary defines *barrier* simply as “*something (such as a fence or natural obstacle) that prevents or blocks movement from one place to another*”. Different professional disciplines have established their version of the concept, in particular when it comes to operational and organizational barrier elements. Therefore, the term “barrier” is defined in many ways such as human barrier, non-technical barrier, operational barrier, non-physical barrier, or organizational barrier [4]. In the context of well integrity, a barrier is an impenetrable object that prevents the uncontrolled release of fluid. Two-barrier philosophy considers two independent well barrier envelopes; *primary well barrier* and *secondary well barrier*. Primary well barrier is the first enclosure that prevents flow from a potential source of flow. Secondary well barrier is the second enclosure that also prevents flow from the potential source of inflow. The secondary well barrier is a back-up to the primary well barrier and it is not normally in use unless the primary well barrier

fails. The principle of the two-barrier philosophy has already been shown in Fig. 2.1; primary well barrier shown as blue line and secondary well barrier as red. For situations where a formation with normal pressure is present, a one-barrier methodology could be acceptable for the abandonment design.

### 2.2.2 Environmental Plug

In the context of the well integrity operating philosophy, one major difference is present between a permanent P&A operation and other activities (e.g. well construction, production, and workover) and that is, the environmental plug. During a permanent P&A operation, in addition to primary and secondary barriers, a supplementary plug is installed close to the surface. It is the shallowest well hindrance that isolates openhole annuli from the external environments that broadly is known as the *environmental plug*. It has also been given, in different literature, other names such as *surface plug*, *openhole to surface well barrier*, and *openhole plug*. These different names have originated due to the definition and functionality of the environmental plug. Some engineers claim that environmental barrier does not provide a well barrier envelope as the surrounding formation cannot hold high pressures and may be bypassed and therefore, it acts as a plug rather than a barrier.

The main function of the environmental plug could be described as to permanently disconnect the open annuli, which are created where casings are cut and retrieved near the seabed, from the external environment. In this manner, three main objectives are achieved; swabbing fluid from sea into the formations through the created annuli is minimized, exposure of surrounding environment to preceding potential hazardous fluids (e.g. drilling fluids) in different annuli is avoided, and potential conduits for leakage from near surface unidentified sources are sealed (Fig. 2.3). However, the obligation to install the environmental barrier is debatable as the cut and retrieval of conductor induces movements that cause the loose sediments to fall down and fill the wellbore. Some authorities do not require the installation of environmental plugs in wells without oil-based fluids in annuli and without zones capable of flow.

## 2.3 Well Barrier Element

A well barrier envelope consists of different well barrier elements. *Well Barrier Element* (WBE) is a physical element, which in itself may or may not prevent flow but in combination with other WBEs forms a well barrier. Figure 2.4 shows a schematic of primary and secondary barriers and the listed WBEs of a platform well, which is in temporarily abandoned status. The WBEs of a permanent well barrier envelope with its best practices is shown in Fig. 2.5.

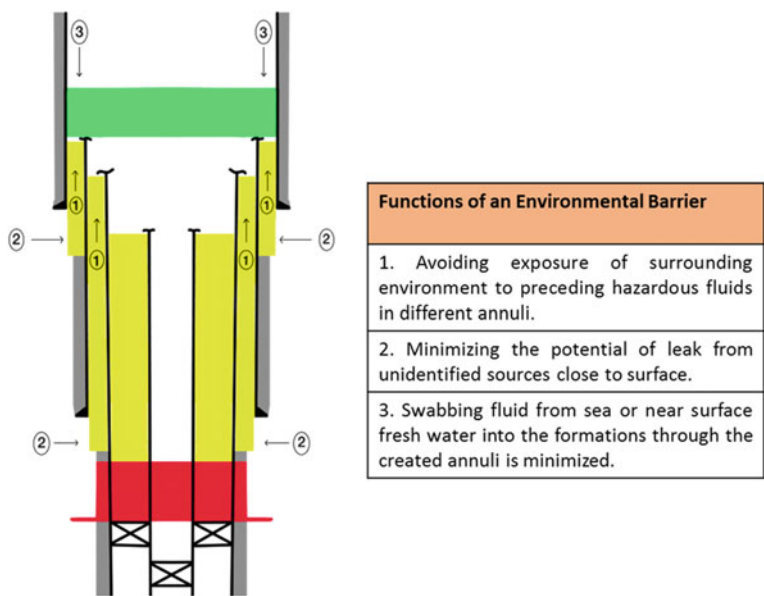


Fig. 2.3 Functions of an environmental barrier shown here in green color

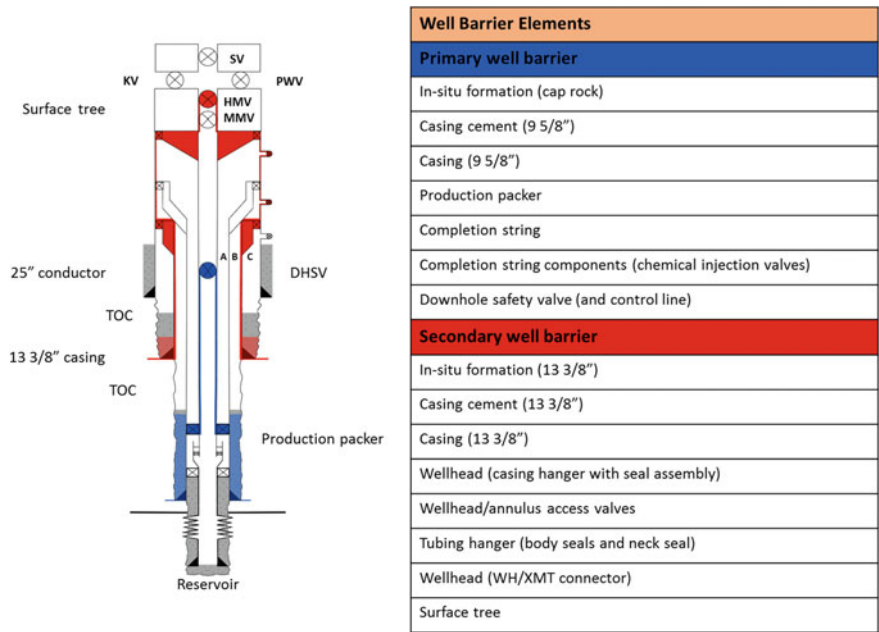


Fig. 2.4 Schematic of well barriers showing well barrier elements for primary and secondary barriers [1]

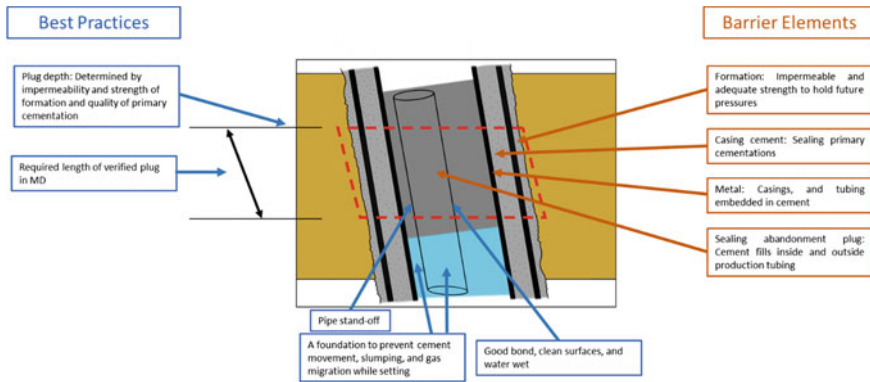


Fig. 2.5 Well barrier elements of a permanent abandonment barrier with its best practices [5]

## 2.4 Plug

Any object or device which is installed inside the wellbore to block a hole or passageway is called a *plug*. In the context of petroleum engineering, plugs are usually categorized into two main groups; *non-mechanical plugs* and *mechanical plugs*. Non-mechanical plugs will be discussed comprehensively in the subject of permanent plugging materials (see Chap. 4). Mechanical plugs are commonly referred to either bridge plugs or mechanical plugs.

### 2.4.1 Bridge/Mechanical Plugs

*Bridge plug (mechanical plug)* is a mechanical device installed and used to provide a seal inside the casing or production tubing. Bridge plugs are categorized as permanent, retrievable, or repositionable [6]. A *permanent bridge plug* has no design feature for intact removal from the conduit. For its removal, a substantial destruction process is necessary. However, a *retrievable bridge plug* possesses a design feature that facilitates removal from the conduit intact [7]. A *repositionable bridge plug* includes a design feature that facilitates its relocation inside the conduit (without removal) while re-establishing its intended function.

Throughout the abandonment process, a deep-set bridge plug can be used as a WBE for temporary abandonment. They provide easier and quicker plug retrieval. However, their utilization as a WBE during permanent abandonment should be avoided due to concerns associated with the long-term durability of mechanical plugs. Nevertheless, mechanical plugs can be used to establish a foundation for placing materials (e.g. Portland cement, thermosetting polymers, geopolymers, etc.) to minimize the risk of contamination while setting.

## 2.5 Well Barrier Illustration

Well barriers and their role in preventing or acting upon leakages from wells may be illustrated in two main different ways; well barrier schematics and barrier diagrams. The concept of documenting well barrier using schematics was introduced to the Norwegian oil and gas industry in 1992 [8]. A *Well Barrier Schematic* (WBS) is a static illustration of a well and its main barrier elements, whereby all the primary and secondary well barrier elements are marked (Fig. 2.4). A *well barrier diagram* is a network illustrating all possible leak paths from the reservoir to the surroundings. The surroundings could be the sea for subsea wells, platform deck for a topside Christmas tree, flowline from a subsea well, ground for onshore wells, etc. Figure 2.6 shows the well barrier diagram for the production well in Fig. 2.4. A well barrier diagram describes the status of barrier elements after a leak occurs. One of the major differences between well barrier diagrams and WBSs, although they have their own specific applications, is the quantification of the barrier diagrams. Well barrier diagrams are widely used to evaluate the likelihood of the consequences illustrated in the diagram.

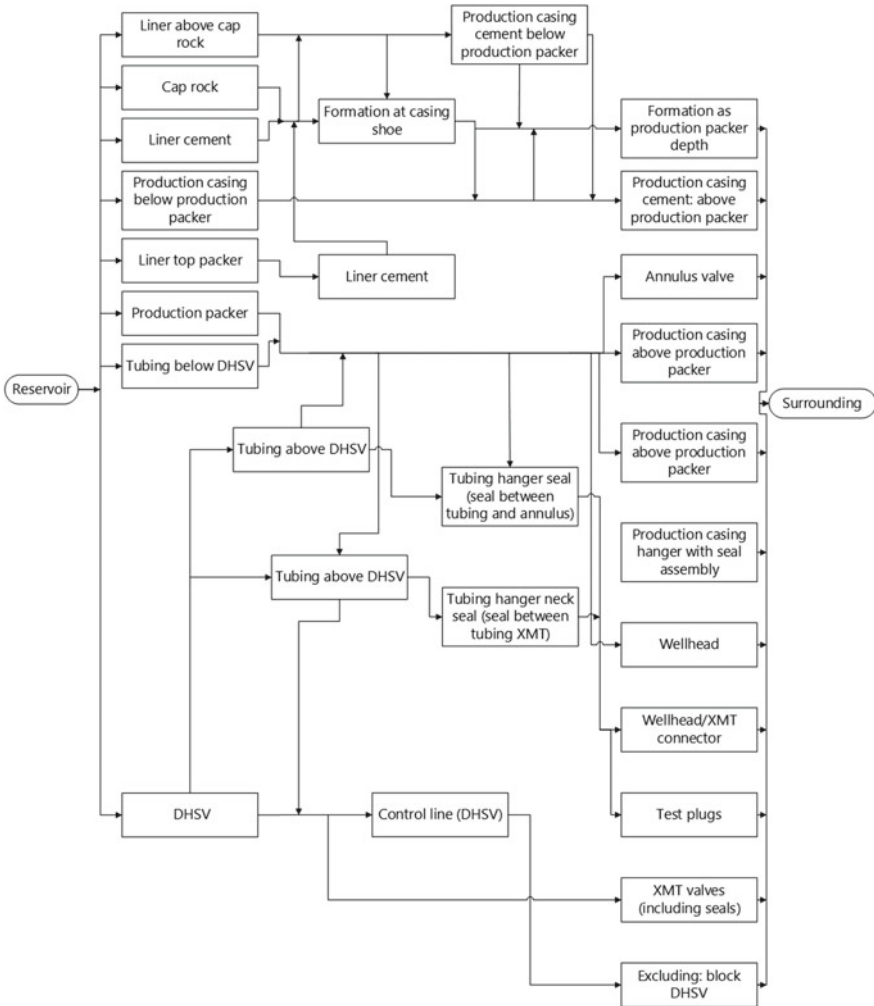
Hence, in the petroleum industry, well barrier schematics and well barrier diagrams are important tools for reliability and risk assessments of a well in all phases of its lifecycle and for well integrity assessments.

## 2.6 Prerequisites for Well Abandonment Design

To perform a competent and efficient abandonment practice, the P&A needs to be considered during well design and well construction in order to reduce the associated risks and saving costs. When a well is selected as a candidate for P&A, the abandonment design is initiated. It is usually recommended to start the planning five years ahead of commencement of the P&A operation. This is due to information gathering regarding changes to the well status, the clarity of work scope and accuracy of time estimation. Detailed planning will require the determination of a detailed sequence of all activities and the resources required to perform the job. In the abandonment design stage, it is necessary to study and document the following: well configuration, stratigraphic sequences of each wellbore, cement logs and cementing operation data and documents, formations with suitable WBE properties, and specific well conditions [1].

### 2.6.1 Well Configuration

It is necessary to know the original and current well configuration. The well configuration includes depths and inclinations, specification of formations that are sources



**Fig. 2.6** Barrier diagram for the production well in Fig. 2.4

of inflow, casing strings, casing cements and top of cements, casing shoes, and wellbores. In addition, all the active sidetracks, and temporarily and permanently abandoned sidetracks are mapped [1].

### 2.6.2 Stratigraphic Sequences

Stratigraphic sequence of each wellbore is identified and documented. The stratigraphic report includes reservoir(s) and information about their current and future



production potential and their containing fluids. In addition, the initial, current and eternal perspective pressures of each flow potential need to be distinguished and estimated. The identification of flow potentials in the overburden is necessary in order to minimize the risk of leaks or kicks over time. It is also necessary to study and adjust the formation fracture gradients for depleted formations [9].

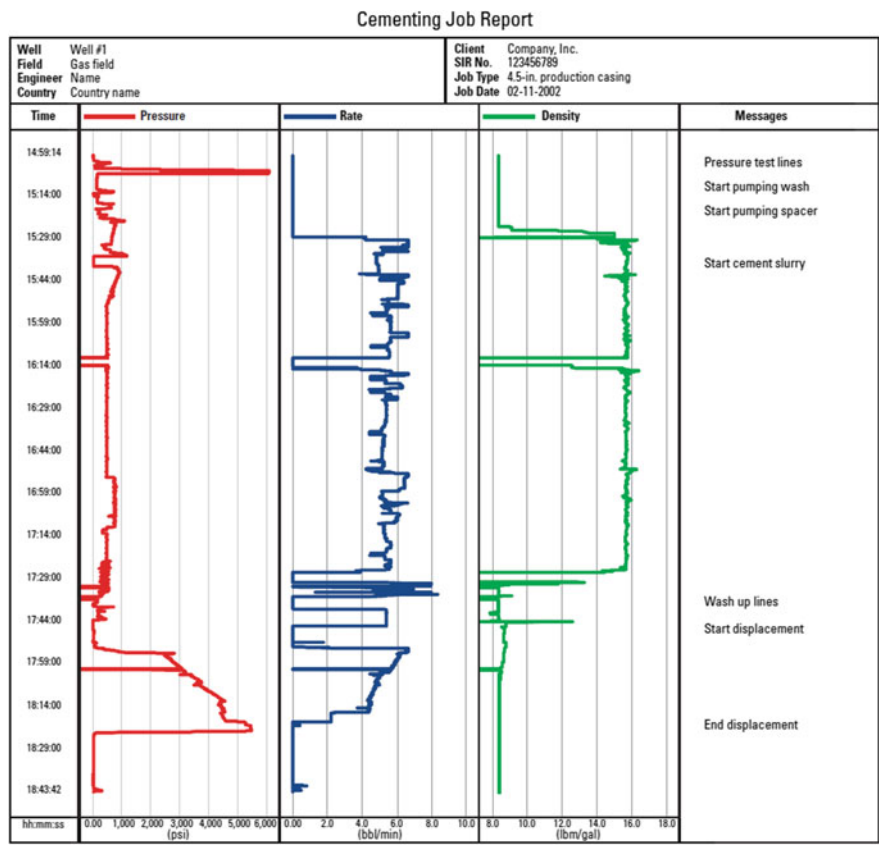
### ***2.6.3 Logs and Cementing Operation Data***

Cement logging is one of the most commonly used verification methods that the petroleum industry relies on to qualify casing cement. It is common practice to log and document the casing cement behind the intermediate casing, and production casing strings; however, not the cement behind the surface casing. There are different types of logs that are used for evaluating casing cement, such as cement bond log (CBL), variable density log (VDL), temperature logs, and sonic logs [10]. In addition, displacement efficiency based on the record from the cement operation (e.g. volumes pumped, returns during cementing, differential pressure, slurry rate, density, etc.) is another set of data which is studied to check the quality of casing cement and identify the *Top of Cement* (TOC). Figure 2.7 shows the recording output from a primary cement job. All of these data are considered during P&A design, in addition to the remedial cement jobs performed on the well throughout its lifecycle.

Considering well cementing log data from old wells during P&A design is a concern as the old logging data are less reliable due to their availability and quality. However, there are P&A designs that rely on old CBL-VDL logs reports. Experience shows that casing cement quality of wells constructed 10–15 years ago are still intact when re-evaluated recently.

### ***2.6.4 Formations with Suitable Well Barrier Element Properties***

Identifying an appropriate formation, for establishing the primary and secondary well barriers across, is a key factor. A suitable formation should possess cap rock properties. It should have sufficient strength to keep the hole in gauge during hole conditioning, hold the exerted hydrostatic pressure of the barrier before it sets (e.g. cement, etc.), and be impermeable or have very low permeability to minimize the risk of integrity loss or providing a conduit for leak around the barrier. Absence of fractures and faults are other properties which in combination with those previously mentioned properties qualify a formation as a suitable candidate for establishing barriers across.



**Fig. 2.7** A typical recording output from a primary cement job (Reprint from Well Cementing) [10]

2.6.5 Specific Well Conditions

To establish a permanent barrier for securing a flow potential, it is necessary to get access to the required depth. However, sometimes there are well conditions that dictate contingency plans. Scale build-up, casing wear, collapsed casing, fill, H<sub>2</sub>S and CO<sub>2</sub> corrosion, asphaltene deposition, erosion, and hydrates are common specific well conditions to be considered in abandonment design [1].

2.6.5.1 Scale Build-up

*Scale* is mineral salt deposits or coating that precipitates and adheres to the surface of metal, rock, or other materials [11]. The precipitation is the result of different factors: a chemical reaction with the surface, a change of pressure or temperature, a change

**Fig. 2.8** Scale deposit caused a restricted access to downhole (Courtesy of Schlumberger)



in the composition of a solution, or a combination of these factors [12]. In severe circumstances, scale build-up creates a significant restriction, or even completely plugs the production tubing. Typical scales are barium sulfate, calcium sulfate, strontium sulfate, iron sulfate, calcium carbonate, iron oxides, iron carbonate, various phosphates, silicates and oxides, and any compounds that are insoluble or slightly soluble in water. For scale removal, a wide range of mechanical (e.g. milling), chemical (e.g. acid wash, non-acid scale dissolver), and scale inhibitor treatment options are available [13]. Figure 2.8 shows a scale build-up in a production tubing.

Scale build-up is a concern for production tubings due to reducing the effective drift, consequently, limiting wireline activities such as running puncher, cutter, caliper log, etc. As production or injection is through the production tubing, the scale build-up does not occur inside the production casing. Retrieval of the production tubing with occurred scale needs special handling of the scale and its disposal, one feasible solution to minimize the effect of scale on P&A activities could be to leave as much pipe in the well as possible. This approach may lead to a rigless P&A operation as retrieval of production tubing requires high pulling capacity, a rig or a jack.

#### 2.6.5.2 Casing Wear

*Casing wear* is often a problem in deep and highly deviated wells where doglegs and large tensile loads on the drill string combine to produce high lateral loads where the drill string contacts the casing. It is a complex process involving variables such as temperature, drilling fluid type, percentage of abrasives in the drilling fluid, tool joint hardfacing, revolutions per minute, tool joint diameter, contact load, and many other factors. In the course of P&A operation, casing wear can compromise

the integrity of casing and result in blowouts, lost circulation, and other expensive and hazardous problems [14]. Therefore, it is necessary to measure and analyze the casing wear that has occurred over the lifetime of a well (e.g. during construction and intervention operations) and consider it in the abandonment design. The risk of induced casing wear while the P&A operation is performed also needs to be studied in the abandonment design.

2.6.5.3 Collapsed Casing

In all wells, there are natural forces and occasionally induced forces, which may cause casing to collapse. The principle cause of *casing collapse* is compaction of formations and the resultant subsidence of the overlying sediments. Figure 2.9 illustrates casing loads resulting from compaction of reservoir rock. The natural forces are created because of tectonic stresses, subsidence, and formation creep. Subsidence widely occurs in large chalk formations where the depleted chalk reservoir is not able to hold the weight of the overburden; however, the intensity in small chalk reservoirs is not high. To visualize the influence of the size of chalk reservoir on subsidence, consider a beam as representing a reservoir with the overburden acting by the load A (Fig. 2.10). A large reservoir cannot withstand the load of the overburden; however, if the reservoir is small, then it can withstand the load of the overburden without experiencing a compaction effect.

The formation creep is intensified and more subjective in plastic salt zones where a non-uniform formation movement exerts point loading on the casing string and causes collapsed casing. In addition to the natural forces, the induced circumstances

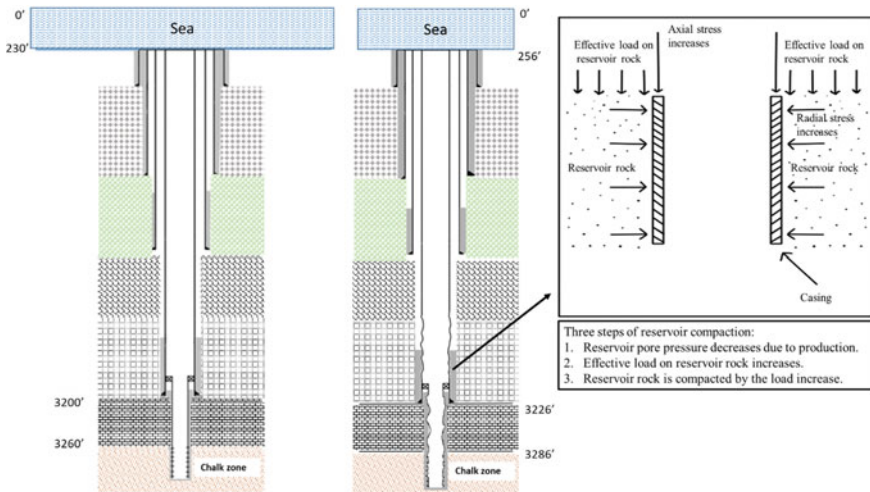
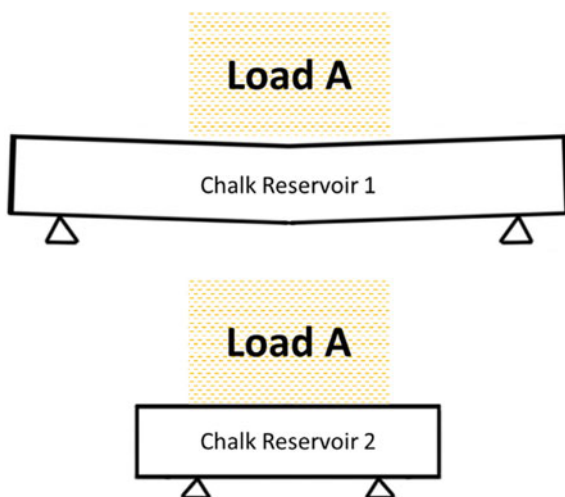


Fig. 2.9 Effect of formation compaction and subsidence on casing string and liner

**Fig. 2.10** Influence of reservoir size on the compaction load in a chalk basin



such as temperature change, and excessive matrix acidizing, play role as well. Temperature change is one of the bases of the induced forces. Temperature changes encountered during the life of the well are small usually and negligible. However, there are situations where temperature variations are not small. Examples of these large temperature variations that can be encountered include geothermal wells used in extracting steam from volcanic areas of the earth, steam-injection wells used in thermal recovery processes, deep gas wells, and wells completed in abnormally hot areas. Excessive matrix acidizing could result in a lack of lateral support around the casing and consequently lead to buckling as the casing is loaded in compression. Furthermore, when the effects of wear, corrosion, and fatigue are added to the stresses on the casing, the potential for failure increases. Casing collapse imposes limited access to downhole and usually requires section milling.

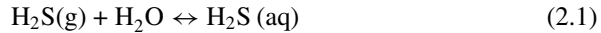
#### 2.6.5.4 Fill

Drill cuttings, collapse fragments, and settled barite may accumulate around the uncemented casing strings and require more force when pulling the casing string. In most cases during P&A operations, the required force is beyond the *pulling capacity* of the working unit or exceeds the tensile strength of casing. Therefore, collapsed casing situation usually dictates section milling.

#### 2.6.5.5 Corrosion

*Hydrogen sulfide corrosion.* The general mechanism for hydrogen sulfide ( $H_2S$ ) attack may be expressed as follows:

H<sub>2</sub>S readily dissolves in water and partially dissociates:



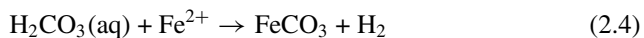
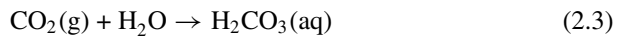
In H<sub>2</sub>S corrosion of mild steel, polymorphous iron sulfide is formed:



A research study [15] shows that for H<sub>2</sub>S corrosion of mild steel, polymorphous iron sulfides can form iron sulfide (FeS), mackinawite (Fe, Ni)<sub>1+x</sub>S where x = 0–0.11), cubic ferrous sulfide (FeO<sub>4</sub>S), troilite (Fe<sub>(1-x)</sub>S where x = 0–0.2), pyrite (FeS<sub>2</sub>), greigite (Fe<sub>3</sub>S<sub>4</sub>), marcasite (FeS<sub>2</sub>). The formed iron sulfide sets up a galvanic cell in which the steel pipe becomes the anode. This reaction is generally assumed to be responsible for the deep irregular pitting observed in sulfide corrosion.

H<sub>2</sub>S corrosion can create cracks in steel pipe in two distinct ways; sulfide stress cracking, and stress corrosion cracking. *Sulfide stress cracking* occurs near room temperature, and it affects the upper parts of wells. This phenomenon occurs during periods of shut-in and cooling down. *Sulfide corrosion cracking* is encountered at high temperatures which occurs at the bottom of wells [16].

*Carbon dioxide corrosion.* CO<sub>2</sub> corrosion is encountered in both gas wells and oil wells and it is reported in different areas such as Louisiana, the North Sea, Germany, the Netherlands, and Gulf of Guinea. Some of the crucial factors which extend CO<sub>2</sub> corrosion of steel include: temperature, pressure, CO<sub>2</sub> content, salt concentration, basic sediments and water, flowing conditions, etc. [16]. The solubility of CO<sub>2</sub> increases as pressure increases and subsequently the pH decreases. However, as the temperature increases, the solubility of CO<sub>2</sub> decreases and as a result, the pH increases. Certain minerals may act as a buffer preventing the pH reduction. The general mechanism of CO<sub>2</sub> attack in the presence of water may be expressed as [17]:



It has been reported that the CO<sub>2</sub> corrosion of steels is highly localized corrosion, which appears in the form of pits, gutters, or attacked areas of various sizes [16]. Figure 2.11 shows a corroded tubing caused by incompatibility between the tubing type and injection water quality.

Retrieval of a corroded production tubing may cause tubing rupture and it may require a multiple fishing operation. Another scenario is when a kill fluid is pumped through the corroded production tubing, the fluid will be exposed to the production casing before killing the well.

Usually corrosion does not attack production casing as only the production tubing is exposed to production or injection fluids. However, production tubing corrosion may indirectly compromise the well integrity during pressure testing. Consider a

**Fig. 2.11** Corroded production tubing due to incompatibility between injection water and tubing type [18]



bridge plug which has been installed in tail pipe of production tubing. The bridge plug is going to be pressure tested and therefore, a fluid is injected through the production tubing. A corroded production tubing with holes exposes the production casing to high pressure and consequently, the casing may burst due to the imposed pressure. Therefore, good knowledge of production tubing condition is necessary prior to starting the P&A operation.

#### **2.6.5.6 Asphaltene Deposition**

*Asphaltenes* are the most aromatic components of crude oil with a high-molecular weight solids, and are insoluble in light alkanes and soluble in aromatic solvents [19]. Several factors such as changes in pressure, temperature, and crude oil composition cause asphaltenes to precipitate from the oil as a black sticky solid material [20]. Traditional methods of removing asphaltene deposits involve mechanical removal, injection of dispersant and solvents, and heat treatment. In P&A operations, in the case of an asphaltene issue, it is a common practice to remove asphaltenes mechanically via scrapers, cutters, coiled tubing deployed jetting tools, or a milling operation [21].

#### **2.6.5.7 Erosion**

*Erosion* is the process of removing material by mechanical action such as particle or droplet impact. The velocity of the particles (e.g. unconsolidated formation) or droplets, which are carried by producing or injecting fluid, provides the energy for erosion of the steel pipe. In addition, fluid flow through the pipe with high velocity creates enough energy for erosion of steel by the fluid. This concept is used for abrasive cutting.

### 2.6.5.8 Hydrates

Natural gas *hydrates* are solid crystalline compounds in which molecules of natural gas are trapped in water molecules under pressures and temperatures considerably above the freezing point of water. Hydrates tend to form in the near surface environment where the temperature is low such as the wellhead, pipelines, and other processing equipment [22]. In the early phase of P&A, mechanical removal via scrapers, cutters, coiled tubing deployed jetting tools, and milling are common hydrate removal practices.

### 2.6.5.9 Containment Assurance of the Abandoned Wells or Fields

*Subsurface containment assurance* is defined as the identification and mitigation of elements that could result in the potential loss of containment of subsurface fluids. The goal of subsurface containment assurance is to ensure no harm is caused to the environment and operated assets, or no impact on well operations due to the leakage of production or injection fluids from their intended zones [23, 24]. One may claim that the subject of subsurface containment assurance fulfills the well integrity requirements, however, in fact it is more comprehensive than the well integrity. It includes well integrity, subsurface integrity, and any aspect of deepwater and surface facilities which are directly relevant to upstream exploration, production, and abandonment operations [25]. As an example the well integrity of abandoned wells or fields might be influenced by nearby injector wells influencing the pressure regime. So possible monitoring of permanently abandoned wells or fields regarding containment assurance may need to be considered.

## 2.7 Well Abandonment Phases

When the abandonment design is ready, the operator submits the program to the local regulatory body. The authority reviews the program and asks for changes or approves it. Once the program is approved, the operator can commence the P&A operation. Approval of the program does not necessarily load any responsibility on the local authority as all responsibilities during P&A and post-abandonment operations are in the hand of the operator.

Generally, a P&A operation may be divided into three phases; phase 1—reservoir abandonment, phase 2—intermediate abandonment, and phase 3—wellhead and conductor removal. This categorization is regardless of the well location (e.g. offshore, or onshore), well type (e.g. exploratory, producing, injecting, etc.), and the well status (e.g. partially abandoned, shut-in, etc.).



### ***2.7.1 Phase 1: Reservoir Abandonment***

Reservoir abandonment starts primarily by inspecting the wellhead and rigging up a wireline unit. The wireline unit is employed to check the access to wellbore by drifting and evaluating the condition of the production tubing by running a caliper log. This preliminary investigation can be regarded as Phase 0—well intervention, and it has a significant influence on time reduction during a P&A operation [26]. In addition, waste handling systems are established for liquid and solid phases. This phase proceeds with an injection test to examine the well integrity. If integrity is maintained, cement slurry is bullheaded to plug the main reservoir and once the cement plug has achieved sufficient strength, its quality is determined by pressure testing. So far, this part of the job is a rigless operation. However, if well integrity is not maintained, a rig needs to be mobilized and a BOP nipped up. Figure 2.12 illustrates a well status where the bullheaded cement is qualified as primary and secondary barriers after conducting the reservoir abandonment phase. Generally speaking, phase 1 is completed when the permanent primary and secondary barriers secure the main reservoir. The production tubing may be retrieved or left in the hole as a part of the well barrier envelope. This phase is completed when the reservoir is fully isolated from the wellbore.

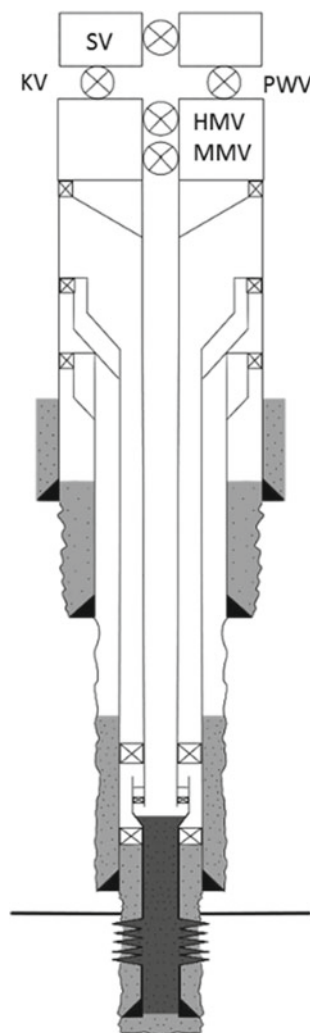
### ***2.7.2 Phase 2: Intermediate Abandonment***

Intermediate abandonment phase includes milling, retrieving casing, setting barriers to isolate intermediate hydrocarbon or water-bearing permeable zones, and installing an environmental plug. The production tubing may partly be retrieved if it has not been retrieved in phase 1. Phase 2 is complete when all the flow potentials identified in the overburden are secured.

### ***2.7.3 Phase 3: Wellhead and Conductor Removals***

In this phase, the conductor and wellhead are cut below the surface or seabed and retrieved. The reason is to avoid any future incident with other marine activities (e.g. fishing activities). In the Norwegian sector of the NCS, this phase is usually regarded as a marine job and not a drilling operation.

**Fig. 2.12** Well status after completing the reservoir abandonment. The assumption prior to bullheading the cement plug is that, the well integrity was maintained and full access to the wellbore was achieved



## 2.8 Disconnecting the Christmas Tree and Assembling Blowout Preventer

It is a common practice to bring the well to temporarily abandoned status or shut-in prior to commencing the permanent P&A operation or after the reservoir abandonment phase. The reason is to reduce the risk of a kick or release of uncontrolled flow while nipping down the Christmas tree and nipping up the BOP. *Nipple-down* is the activity of disassembling well-control equipment on the wellhead. *Nipple-up* is the process of assembling well-control equipment on the wellhead. So, as we discussed earlier in this chapter, it is necessary to have two independent well barrier envelopes.

This means that when the Christmas tree is disassembled still two intact well barrier envelopes need to be in place. Therefore, it is crucial to understand wellhead and the Christmas tree systems for disconnecting the reservoir from the environment until the BOP is rigged up.

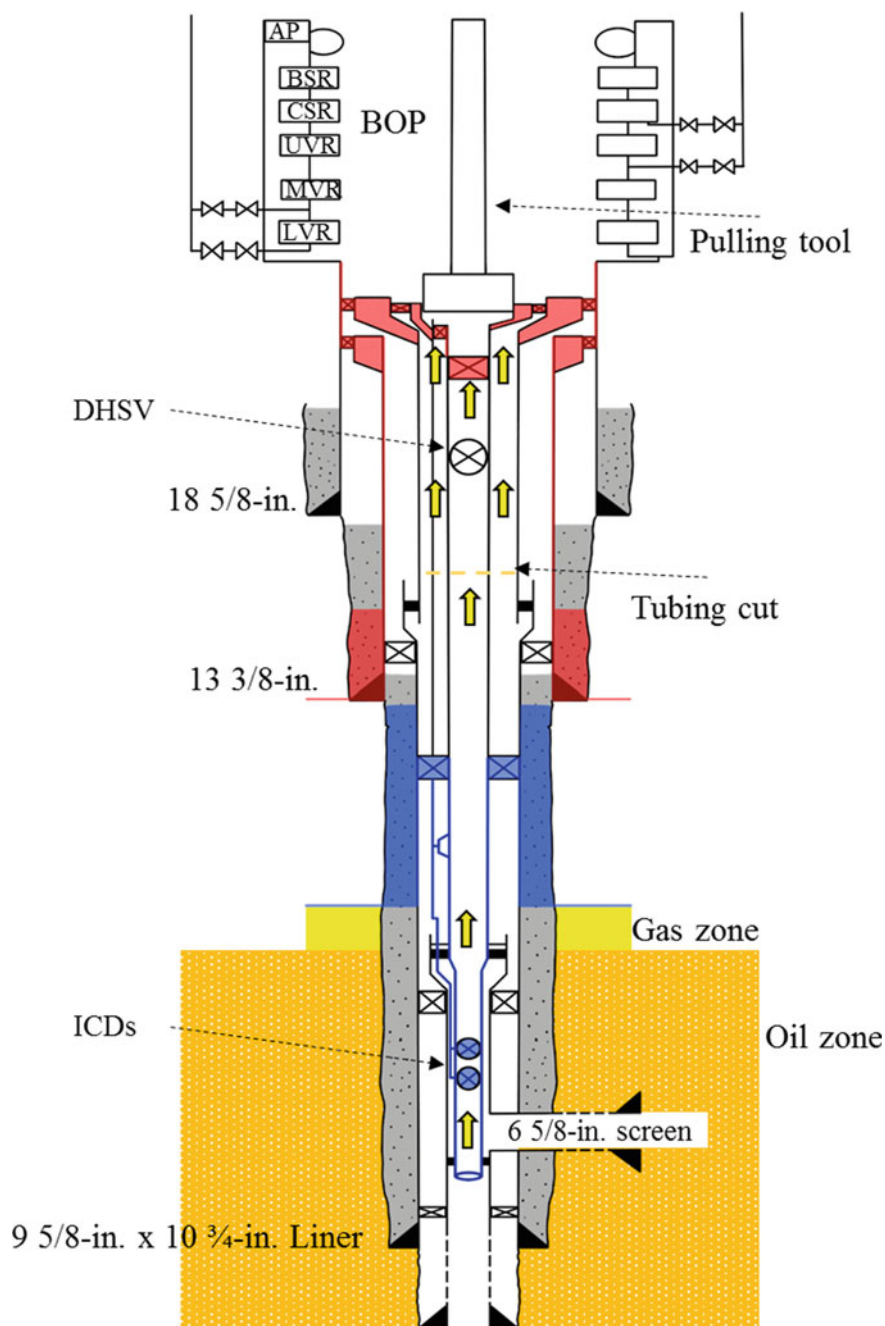
In October 2016, a serious well control incident occurred on a production well in the Troll field, in the North Sea. This incident began after permanently plugging the existing flow paths in the well. Then, a sidetrack was about to be drilled. In connection with pulling the tubing hanger, the completion string with the top drive was suddenly raised six meters without control. Large quantities of fluid and gas flowed out through the rotary table. The blowout lifted the 2.5 tons hydraulic slips and threw some two tons of bushings several meters across the drill floor and the liquid column reached the top of the derrick about 50 m above the drill floor. Fortunately, nobody suffered physical injury, but it could have led to a major incident with loss of several lives. The Norwegian Petroleum Safety Authority investigated the incident and concluded that the direct cause of the incident was the release of a large quantity of trapped reservoir gas underneath of the tubing hanger. Although a BOP wellhead connector test had been performed six hours before the incident, a gas leak that occurred during these six hours, caused the incident [27] (Fig. 2.13).

Another crucial factor that might be considered is wellhead fatigue loads that will be exerted by the BOP stack during P&A operations. Therefore, wellhead systems and their advantages and limitations are reviewed in this chapter.

### 2.8.1 Wellhead Systems

A wellhead system is the surface termination of a wellbore and it is composed of spools, valves, and assorted adaptors that provide pressure control of a production well. Wellhead systems incorporate facilities for installing casing hangers, tubing hanger, and Christmas tree. The wellhead systems can be categorized depending on the place where the wellhead is installed as *surface wellhead* systems and *sub-sea wellhead* systems [28, 29]. There are two types of wellheads used for surface applications; spool type and compact type. Other names used for the compact type wellheads are speed head, unitized head, bowl head, multi-bowl head, and unihead. Each of these configurations have their own advantages and challenges in the course of P&A. Table 2.2 lists advantages and challenges for each system. As the subject of wellheads is an extensive area, wellhead systems will be reviewed based on the first classification system.

As wellhead type is related to the number of connections or components and consequently the risk of leakage, it is important to analyze the wellhead condition. In March 2012, on Elgin installation (approximately 200 km east of Aberdeen, Scotland) located in the North Sea experienced a major incident of uncontrolled release of hydrocarbons to atmosphere. In this incident, reservoir gas from the Chalk formation leaked to the A-annulus and in a further step from A-annulus to B-annulus, and then to C-annulus. Due to poor sealing capability of wellhead components and connections,



**Fig. 2.13** Leak path which caused trapped gas beneath the tubing hanger in Troll field [27]

**Table 2.2** Advantages and limitations of wellhead systems with respect to P&A operations

Wellhead type	Advantages	Disadvantages
Spool type	<ul style="list-style-type: none"> <li>• The relative simplicity of the suspension and sealing systems</li> </ul>	<ul style="list-style-type: none"> <li>• Requires removal and the re-installation and testing of the BOPs for the removal of each casing head spool</li> <li>• They have more connections and consequently more risk of leakage</li> </ul>
Compact type	<ul style="list-style-type: none"> <li>• Less height</li> <li>• Fewer potential leak paths</li> </ul>	<ul style="list-style-type: none"> <li>• Lack of tolerance of damage to the hanger sealing areas</li> </ul>

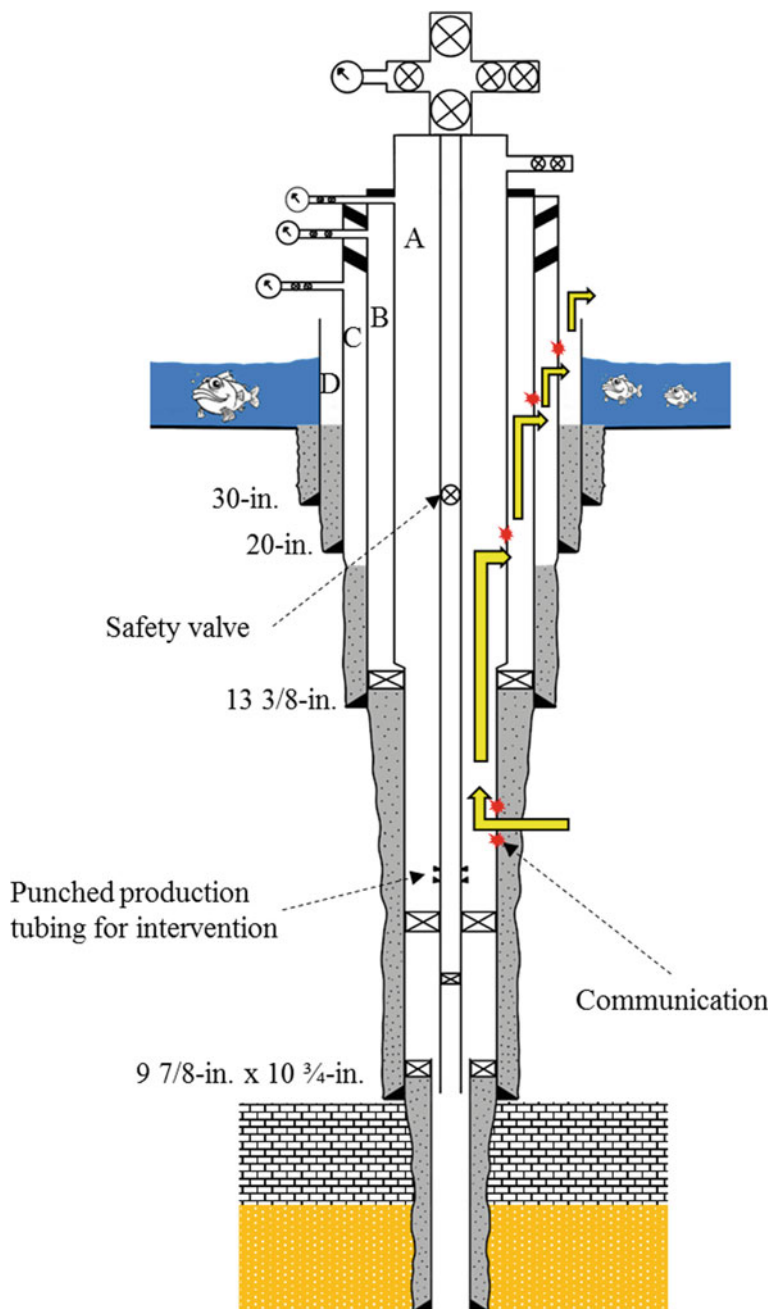
the gas leaked to the conductor, D-annulus [12]. As the conductor annulus, D-annulus, is not connected to any barrier for preventing leaks, the gas leaked to the environment uncontrollably, Fig. 2.14. This incident had no loss of life and well control was achieved by killing the well by pumping kill mud [30].

### 2.8.1.1 Surface Wellhead

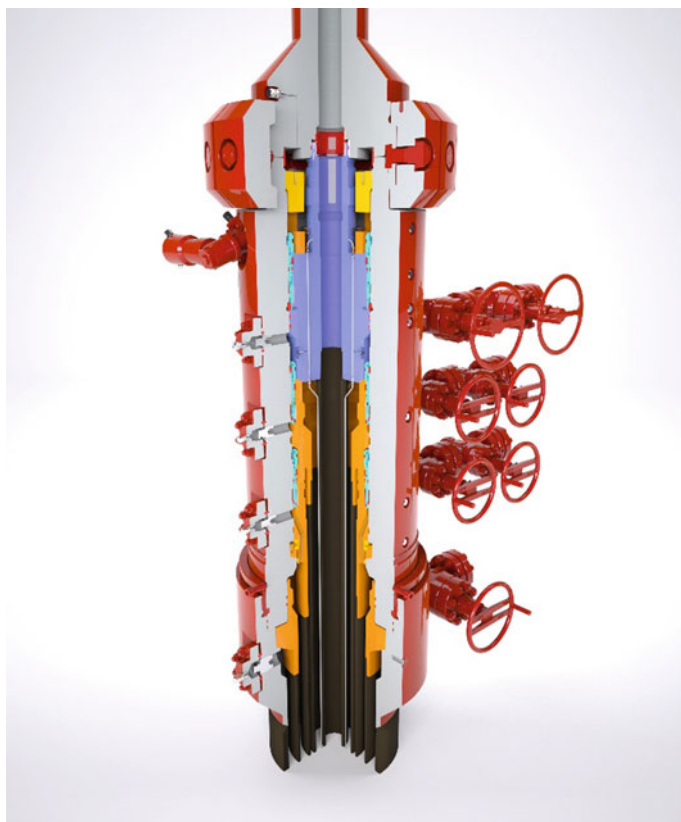
Surface wellheads are used both onshore and offshore. Primary functions of the surface wellhead include pressure isolation, pressure containment, casing and tubing weight suspension, and the Christmas tree housing. shows a surface wellhead model and its main sections; starter head at the bottom, spools for casing hangers, spool for tubing hanger, adaptor, and valves for access to different annuli. There are several factors to be considered in selection of a wellhead during well construction; value, field history, operator preference, lifespan, temperature range, fluid environment, pressure range, mechanical configuration, external loading, and installation or energization method. Some of these factors may endanger the wellhead condition and its performance during the P&A. Therefore, investigating the wellhead quality and running a fatigue analysis are crucial in the P&A design phase (Figs. 2.15 and 2.16).

### 2.8.1.2 Subsea Wellhead

The main functions of subsea wellheads are the same as surface wellheads. Nevertheless, due to subsea conditions, there are some additional functions such as serving a structural and pressure-containing anchoring point on the seabed for the drilling and completion system, and facilitating guidance, mechanical support, and connection of the systems used to drill and complete the well. A standard subsea wellhead system (Fig. 2.17), typically consists of drilling guide base, low-pressure housing (typically 30-in.), high-pressure wellhead housing (typically 18 3/4-in.), casing hangers, metal-to-metal annulus sealing assembly, bore protectors and wear bushings, and running and test tools. In the course of drilling subsea wells, the Low-Pressure Wellhead Housing (LPWH), conductor, and guide base are run at the same time.



**Fig. 2.14** The schematic of the leak path from Elgin, platform well [30]



**Fig. 2.15** Surface wellhead model with its main different sections. (Courtesy of TechnipFMC)

The subsea wellhead is placed on the seabed and the BOP is installed on top of it. Waves and current forces acting on the marine riser during drilling, production, intervention or P&A operation will cause movements. A subsea wellhead will be exposed to external loads: static and cyclic combinations of bending and tension (compression). The cyclic loads can cause fatigue damage to the well and create well integrity issues. If the subsea wellhead fails then its pressure vessel function will be lost, which can lead to HSE issues [31].

### 2.8.1.3 Special Consideration for Wellhead Systems

*Casing/tubing hanger lockdown*—The incident occurring on Troll field [27], could have been prevented if the well was completed with a horizontal Christmas tree rather than a vertical Christmas tree. The horizontal and vertical X-mas trees are discussed in more detailed in this chapter. In offshore wells, casing/tubing hanger is installed and locked down inside a horizontal Christmas tree and the pressure beneath the tubing

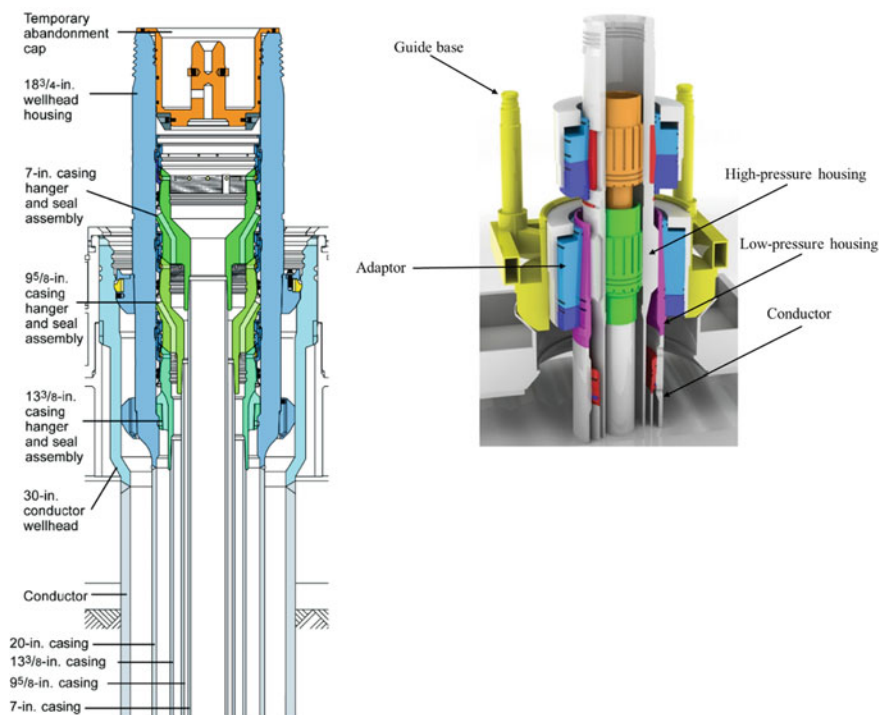
**Fig. 2.16** Surface wellhead with vertical XMT.  
(Courtesy of TechnipFMC)



hanger can be measured. However, when a vertical Christmas tree is selected for well completion, the casing/tubing hanger is installed and locked down to the wellhead prior to installation of the tree. For onshore wells, the lockdown and installation of casing/tubing hanger is similar to the scenario for vertical trees.

*Fatigue life of a wellhead system*—One of the challenges during P&A design and operation, especially for subsea wells, is the fatigue loading exerted on wellheads by the BOP. Some of the older wells, drilled two to three decades ago, have been drilled with BOPs that were smaller and lighter than current designs; therefore, the wellhead design was different and subsequently the wellheads response to induced fatigue. Another challenge linked to the afore-mentioned challenge is BOP pressure rating requirements legislated by some authorities. Consider an old well where its wellhead connector has been pressure rated for 5 kpsi but requirements ask for the utilization of a 10 or 15 kpsi BOP, although a depleted well may require a lower BOP pressure rating. In addition, the challenges associated with fatigue life of wellhead systems is more of a concern in subsea wells due to sea currents. Another concern regarding fatigue is updated regulations. For example: in 1975, a 13 3/8-in. BOP could have an approximate weight of 20 metric tons, however, in 2016, a 18 5/8-in. BOP could weigh up to 400 tons. Therefore, nowadays, the fatigue introduced to the wellhead is much higher compared to old BOPs. In addition, there are wells designed





**Fig. 2.17** A standard subsea wellhead system and its main sections. (Courtesy of SPE)

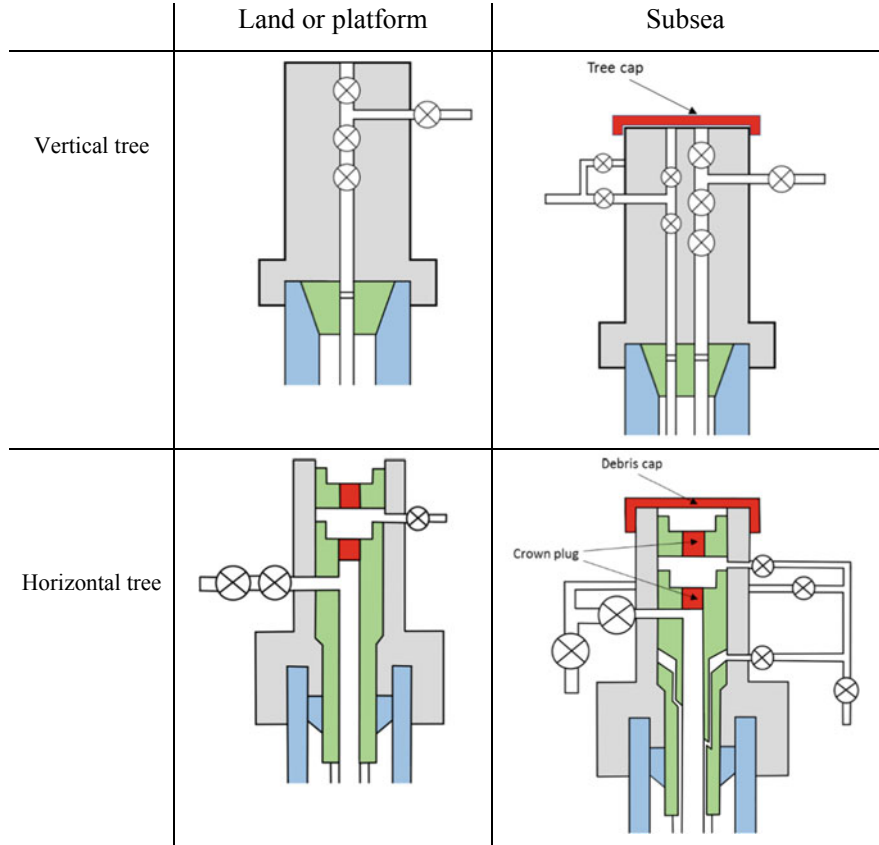
and completed for a specific service life with regards to time, however, the service life has extended more (up to a decade) than the design life. These wellheads are a point of failure for wells with strong aquifers where the current reservoir pressure is approximately equal to the initial reservoir pressure.

Recently, a new generation of BOP system being developed is electrical based, which does not require a hydraulic accumulator (Kooimey) unit. This system is lighter compared to previous and available BOP systems.

### 2.8.2 The Christmas Tree Systems

The equipment at the top of a well is called “*Christmas tree*”. The Christmas tree is assembled of valves, spools, pressure gauges and chokes which is fitted to the wellhead (see Fig. 2.16) of a completed well. The *Christmas tree* (XMT) provides a controllable interface between the well and production facility. It is also called by other names such as cross tree, X-tree, or tree. The functions of a tree are addressed as follows: allowing reservoir fluid to flow from wellbore to the surface facilities in a safe and controlled manner, safe access to the wellbore to perform well intervention

procedures, allowing injection of fluids, providing access to a hydraulic line for a *Surface Controlled Subsurface Safety Valve* (SCSSV), providing the electrical interface for instrumentation and the possible electrical wiring for an *Electrical Submersible Pump* (ESP). The XMT is installed on the last casing spool, tubing head adaptor, or high-pressure wellhead housing for a subsea well. They are available in a wide range of sizes and configurations, such as low-or high-pressure capacity and single-or multiple completion capacity. It is a norm to purchase the XMT and wellhead from the same manufacturer due to compatibility. Generally, there are two different approaches to categorize the trees; depending on the place where the XMT is installed or based on the arrangement of the valves and gauges. The first approach divides the trees into two main groups; surface trees (dry trees) for land/platform wells, and subsurface trees (wet trees) for subsea wells. The second approach divides the trees into two main classes based on the configuration of the valves and gauges; vertical trees and horizontal trees. Figure 2.18 illustrates four different configurations of tree

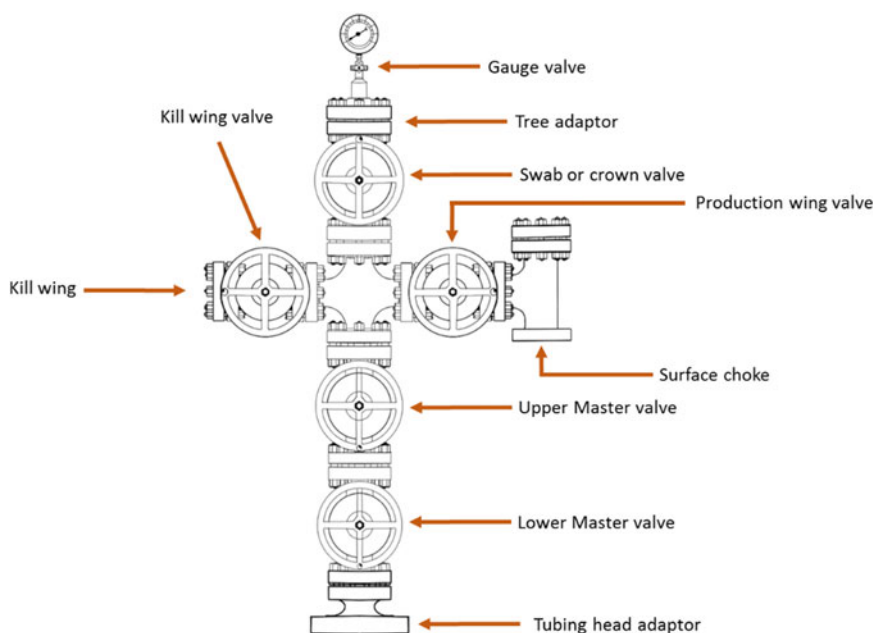


**Fig. 2.18** Four different configurations of XMT valves for land/platform and subsea wells [3]

valves. For simplicity and relevancy to P&A, the second approach is preferred and used for discussion in this book.

### 2.8.2.1 Vertical Christmas Tree

Figure 2.19 shows a drawing of a surface vertical tree. The master valve is located above the tubing head adaptor and its function is to allow a well to flow or to shut-in the well. Typically, there are two master valves; lower master valve, and upper master valve. The two valves are often used because they provide redundancy; if one valve cannot function properly, the other valve is engaged. The upper and lower master valves are shown in Fig. 2.19. Tee type fitting (known as T-block) provides diversion of the vertical flow to the horizontal flowline. Usually a wing valve is located on the side of the tree and used for controlling or isolating production from the well to surface facilities. Based on the tree design, which is the operator requirement, one or two wing valves can be fitted to the tree. As a common practice, usually operators require two wing valves; one for production, known as *Production Wing Valve* (PWV), and another one as backup or as a *Kill Valve* (KV). After the wing valve a small restriction, which is referred to as the choke, is used to control the production rate of the well. On the Christmas tree, the topmost valve is called the *Swab Valve* (SV). The swab valve provides access to the borehole for well intervention operations



**Fig. 2.19** Typical surface vertical Christmas tree



**Fig. 2.20** A dual-bore vertical subsea tree which allows to monitor annulus pressure. (Courtesy of Schlumberger)

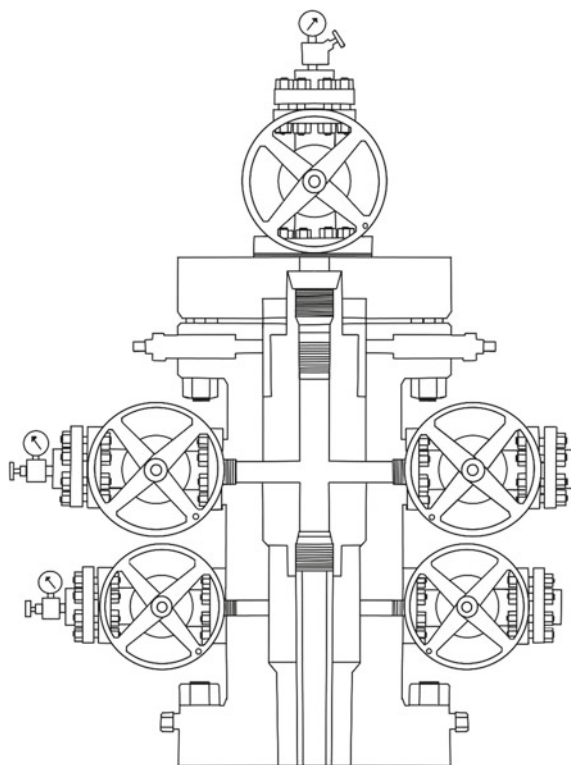
performed by wireline, slickline, coiled tubing, or a snubbing unit. The inlet of the swab valve is covered by a flange that is called a T-Cap, which allows a wireline lubricator, snubbing unit BOP, or coiled tubing to connect to the well. Finally, a top pressure gauge sits on top of the T-Cap to show the well pressure. The vertical trees can be used for both surface and subsea wells. However, the subsea application needs different interfaces with respect to manipulating the tree valves and access to the A-annulus (Fig. 2.18). It is notable that the configuration of valves on the vertical trees for subsea and surface trees are the same; however, due to the subsea conditions and remotely manipulating the valves, the interface of a subsea well is different (see Fig. 2.20). The vertical subsea tree can be a single-bore or dual-bore (see Fig. 2.18) and this can make a difference to the P&A operation.

Throughout construction and completion of land/platform wells or subsea wells with the vertical XMT, the tubing hanger is installed inside the wellhead (see Fig. 2.15) and then the vertical XMT is installed on top of the wellhead. Therefore, in order to retrieve the production tubing, the vertical XMT must be nipped-down. Accordingly, to maintain well integrity during the tubing retrieval, the BOP must be installed.

### 2.8.2.2 Horizontal Christmas Tree

The advent of horizontal trees has initially been linked to completion of subsea wells. It is necessary to mention, before any comparison of horizontal and vertical subsea trees is made, the parts and subassemblies are very similar. In horizontal trees, the valves are positioned on the sides of the tree body (Fig. 2.21). The difference between

**Fig. 2.21** Illustration of a horizontal Christmas tree



horizontal and vertical trees arises largely from the configuration of the valves rather than novel design. One of the main reasons that persuades operating companies toward using horizontal trees are challenges related to subsea well intervention operations. Mostly, a subsea well intervention arises from problems related to the tubing and SCSSV and therefore, ready access to the production tubing and SCSSV, without disassembling the tree, are primary design criteria. Thus, the position of valves on a vertical tree are moved to the sides of the tree and the tubing hanger sits inside the horizontal tree. In this manner, during a subsea well intervention, the BOP is positioned above the horizontal tree and tubing is retrieved without nipping down the tree. Consequently, the workover operation is easier performed, and more efficient. In addition, concerns regarding nipping the tree down/up are minimized. Table 2.3 presents the notable differences between the subsea vertical and horizontal trees. Figure 2.22 depicts a horizontal subsea XMT.

During drilling of a subsea well, the following are run at the same time: LPWH, conductor, and guide base. If the well is planned to be completed with a horizontal XMT, after installation of the subsea wellhead system, the horizontal XMT is installed and subsequently the BOP is installed on top of it and then drilling is resumed. Then in the completion phase, the tubing hanger sits inside the horizontal XMT. In other words, tubing retrieval does not necessitate the removal of the horizontal XMT.

**Table 2.3** The most notable differences between subsea trees; vertical and horizontal

Vertical XMT	Horizontal XMT
<ul style="list-style-type: none"><li>• Master and swab valves in bore</li><li>• Tree run after tubing (tree lands on and stabs into the tubing hanger)</li><li>• Tubing hanger orients via wellhead</li><li>• External tree cap run after tree landed/tested</li><li>• Tubing hanger seals normally isolated from well fluid</li></ul>	<ul style="list-style-type: none"><li>• No valves in the vertical bore of the well</li><li>• Tree run before tubing (tubing hanger lands in tree body)</li><li>• Tubing hanger orients directly from tree (limits tolerance stack-up)</li><li>• An internal tree cap is used as a secondary pressure barrier above the tubing hanger, two crown plugs are installed by wireline unit</li><li>• The tubing hanger seals are continuously exposed to well fluids</li></ul>

**Fig. 2.22** A horizontal subsea Christmas tree



Where the installation of a BOP is required, it is nipped-up on top of the horizontal tree.

In order to perform an efficient and safer permanent P&A operation, it is necessary to understand the strength and weakness of each type of tree system. Table 2.4 tabulates the advantages and concerns regarding the tree systems.

2.8.3 Assembling BOP

In the course of a P&A operation, regardless of the well type (i.e. land/onshore or off-shore) and the XMT type (i.e. horizontal or vertical), at some point, the utilization of a BOP is unavoidable. Therefore, the primary and secondary temporary well barrier envelopes shall be established and maintained to secure the well while disassembling the XMT and assembling the BOP. Theoretically, this procedure may be considered

**Table 2.4** Comparison between advantages and concerns of subsea vertical and horizontal tree systems

Tree system	Advantages	Concerns
Vertical	<ul style="list-style-type: none"> <li>• Lighter than horizontal trees</li> <li>• To nipple-down the tree, there is no need to retrieve production tubing</li> </ul>	<ul style="list-style-type: none"> <li>• Seldom accommodate larger than 5 ½-in. production tubing</li> <li>• Not designed to take the load from BOP</li> <li>• Tubing/casing hanger is locked to the wellhead before tree is installed; consequently, pressure under the tubing hanger cannot be measured</li> </ul>
Horizontal	<ul style="list-style-type: none"> <li>• BOP is installed on top of the tree</li> <li>• The tree has a lower height</li> <li>• Work efficiency is improved (e.g. nipping down/up and testing the tree during well intervention is avoided)</li> <li>• Accommodate up to 7-in. production tubing</li> <li>• Tubing/casing hanger is locked in the tree itself; consequently pressure under the tubing hanger can be measured</li> </ul>	<ul style="list-style-type: none"> <li>• Heavier than vertical trees</li> <li>• Inaccessibility to different annuli except A-annulus</li> </ul>

for four different well completion scenarios (Fig. 2.18); a land/platform well completed with the vertical tree, a subsea well completed with the vertical tree, subsea well completed with the horizontal tree, and a land/platform well completed with the horizontal tree. However, the latter scenario is less likely to be accomplished due to some practicality issues such as large weight of the horizontal tree, inaccessibility to different annuli except the A-annulus, etc.

### 2.8.3.1 Assembling BOP—Land/Platform Well with the Vertical Tree

Consider a platform well which has been completed with the vertical tree (Fig. 2.23). To establish the primary temporary barrier, there should be enough casing cement below and above the production packer in the B-annulus and no reported sustained casing pressure in the A-annulus (see Fig. 2.14 for definition of A-, B-, and C- annuli). If these assumptions are valid, the primary barrier envelope is achieved by installation of a bridge plug in the tail pipe. The bridge plug and primary well barrier envelope are pressure tested for assurance that well integrity is maintained. The primary well barrier elements, illustrated in Fig. 2.23, are listed and marked with a blue line.

For establishing the secondary temporary well barrier envelope, there should be enough casing cement above the production packer in the B-annulus, no sustained casing pressure in the B-annulus, and production casing maintains integrity. Note that the same interval of casing cement, which is used as an element for the primary barrier,



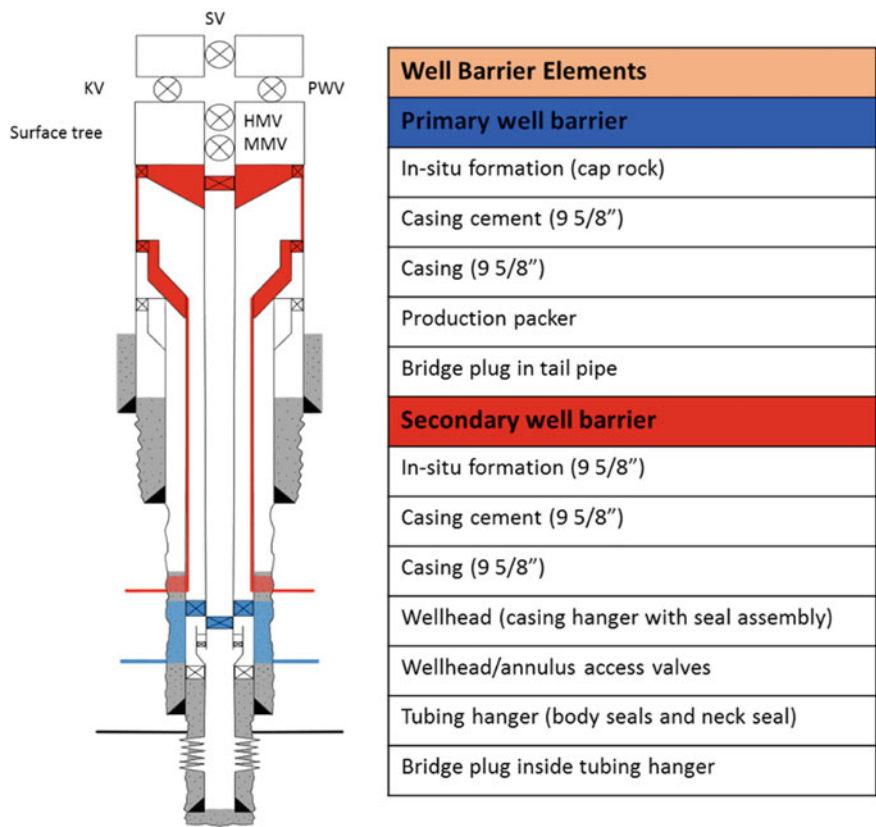


Fig. 2.23 List of well barrier elements of a platform well with the vertical tree

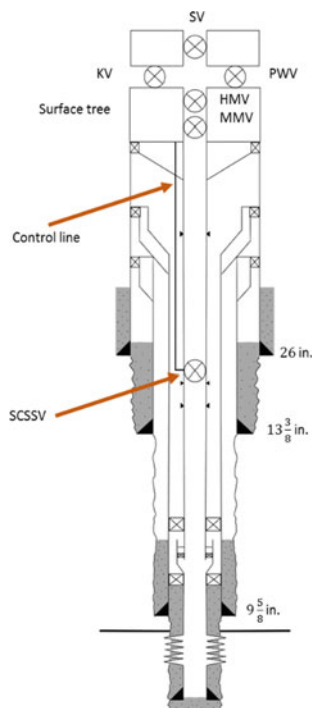
cannot be used as an element for the secondary barrier (see Fig. 2.23). If the above-mentioned assumptions are valid, the secondary barrier envelope is achieved by installation of a bridge plug inside the tubing hanger. The bridge plug and secondary well barrier envelope are pressure tested prior to commencing nipping-down the tree. The secondary barrier elements are listed and marked with a redline in Fig. 2.23.

Where a well has been completed with a *Downhole Safety Valve* (DHSV), the DHSV can be used as a well barrier element in the primary well barrier envelope when it is qualified by a function and pressure test.

**Example 2.1** A platform well (Fig. 2.24) has been drilled and completed with the vertical tree in 1985. The TOC in the B-annulus is below the permanent packer and the well suffers from sustained casing pressure in the A- and B-annulus. Caliper log shows big holes along the production tubing (shown with triangle on Fig. 2.24). Operator decided to permanently plug and abandon the well. Through the operation, a BOP is necessary to control the well pressure. Make a list of the primary and secondary well barrier elements for nipping-down the tree and nipping-up BOP.



**Fig. 2.24** WBS of a platform well with the vertical tree



**Solution** It is recommended to squeeze cement the perforations and extend it up to the liner packer. Pressure test the cement plug and if it is qualified, bleed off the A-annulus and the B-annulus. If the A-annulus and the B-annulus pressures do not build up, a plug is installed inside the tubing hanger. Then, the primary and secondary well barrier elements, temporary barriers, could be as follows:

Temporary Well Barrier Elements
Primary well barrier
In-situ formation (cap rock)
Casing cement (9 5/8")
Casing (9 5/8")
Liner cement
Liner
Cement placed inside liner
Secondary well barrier
In-situ formation (13 3/8")
Casing cement (13 3/8")
Casing (13 3/8")
Wellhead (casing hanger with seal assembly)
Wellhead/annulus access valves
Tubing hanger (body seals and neck seal)
Plug inside tubing hanger

But if the squeezed cement is not qualified and the A-annulus and B-annulus pressures are building up, then a bridge plug should be installed inside production tubing, below the permanent packer, and A- and B-annuli need to be killed by unconsolidated sand slurries or heavy fluid. Here the assumption is that the SCSSV has successfully passed the pressure test. A plug is installed inside tubing hanger. Then, the primary and secondary well barrier elements, temporary barriers, could be as follows:

Temporary Well Barrier Elements
Primary well barrier
In-situ formation (cap rock)
Kill fluid or unconsolidated sand slurry (B-annulus)
Production casing (9 5/8")
Kill fluid or unconsolidated sand slurry (A-annulus)
Permanent packer
Production tubing
Bridge plug in tailpipe
Secondary well barrier
In-situ formation (13 3/8")
Casing cement (13 3/8")
Casing (13 3/8")
Wellhead (casing hanger with seal assembly)
Wellhead/annulus access valves
Tubing hanger (body seals and neck seal)
Plug inside tubing hanger

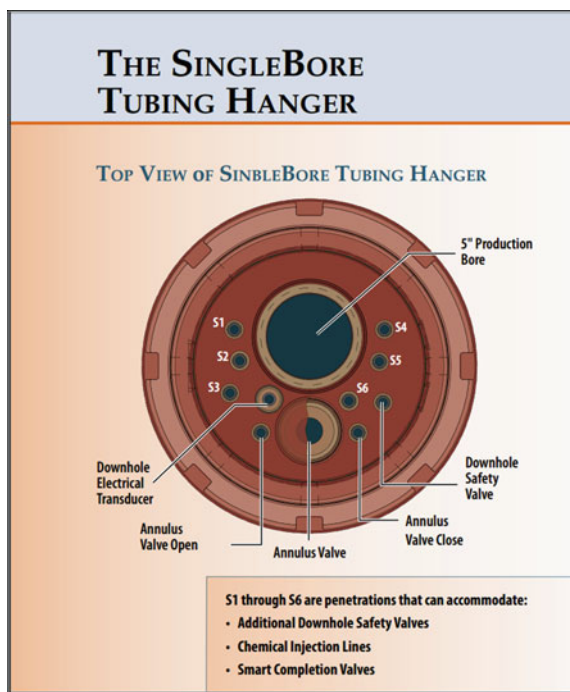
### 2.8.3.2 Assembling BOP—Subsea Well with the Vertical Tree

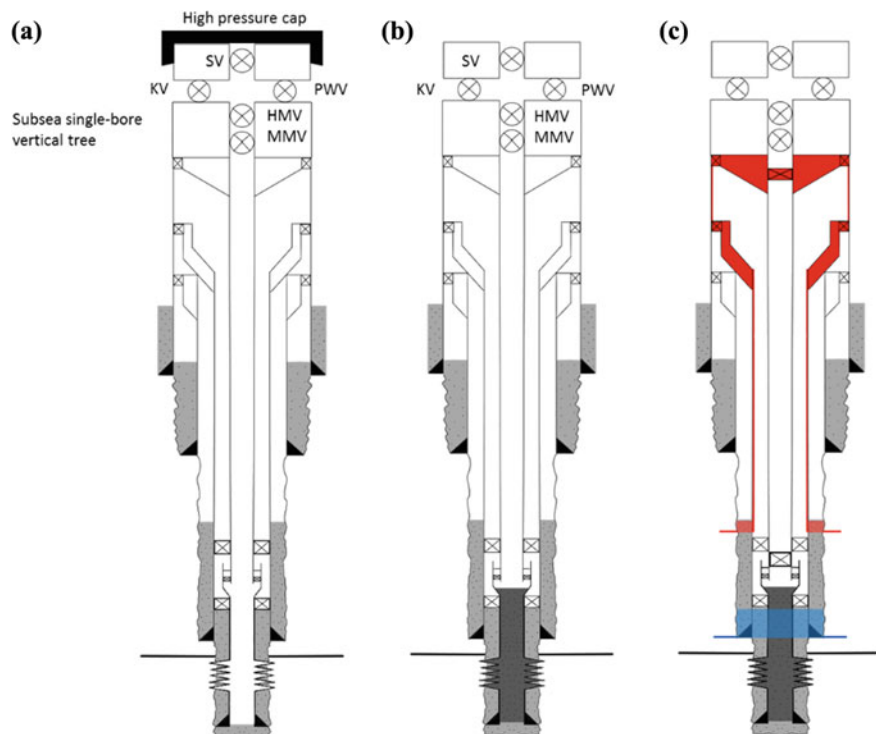
Vertical subsea trees may be divided into two main groups considering their tubing hanger configuration: single-bore (mono-bore), and dual-bore trees. Figure 2.25 shows configuration of single-bore tubing hanger with an annulus valve and penetrations for control lines and chemical injection lines. Nowadays, single-bore vertical subsea trees are barely used for the completion of subsea wells; however, dual-bore vertical trees are more commonly used for the completion of subsea wells as they provide access to the A-annulus.

Figure 2.26a is an illustration of a subsea well which has been completed with a single-bore vertical subsea tree. It is a conventional procedure to bullhead cement into the main reservoir through the production tubing when the production tubing is in good condition. Then, the cement plug is pressure tested. If it passes the test successfully, it can be used as primary temporary barrier and primary permanent barrier (Fig. 2.26b). However, if it does not pass the pressure test, the primary and secondary well barrier envelopes are established by rigging up a wireline unit. A wireline BOP is positioned on top of the tree, and a bridge plug is installed in the tailpipe. The envelope is tested and if it maintains its integrity, a secondary temporary barrier is established by placing a bridge plug inside the tubing hanger and verified by pressure testing the barrier envelope (Fig. 2.26c).

Dual-bore vertical subsea trees provide direct access to the production and annulus bores via a completion riser. As there is more than one bore inside the tubing hanger,

**Fig. 2.25** Configurations of tubing hanger for subsea well completed with the vertical trees. (Courtesy of Dril-Quip)





**Fig. 2.26** Subsea well completed with the single-bore vertical tree

two bridge plugs are required to establish the secondary barrier and consequently, a dual-bore riser is required. A wireline BOP is installed on top of the tree and bridge plugs are installed and eventually, the envelopes are pressure tested. It is noteworthy to know that a dual-bore tubing hanger does not affect establishment of the primary temporary barrier (see Fig. 2.27).

### 2.8.3.3 Assembling BOP—Subsea Well with the Horizontal Tree

Often, it is assumed that nipping up the BOP for wells completed with horizontal trees is not as complex as for wells completed with vertical trees; however, that is not true. Maybe the reason for this belief is rooted in the reality that the BOP is installed on top of the horizontal tree and there is no need to nipple-down the tree and consequently, there is no need to establish the primary and secondary temporary barriers. Indeed, to get access to the wellbore, the high-pressure tree cap needs to be removed (see Fig. 2.28), and pressure underneath of the tree cap needs to be controlled. Therefore, a well control equipment is necessary and will be employed.

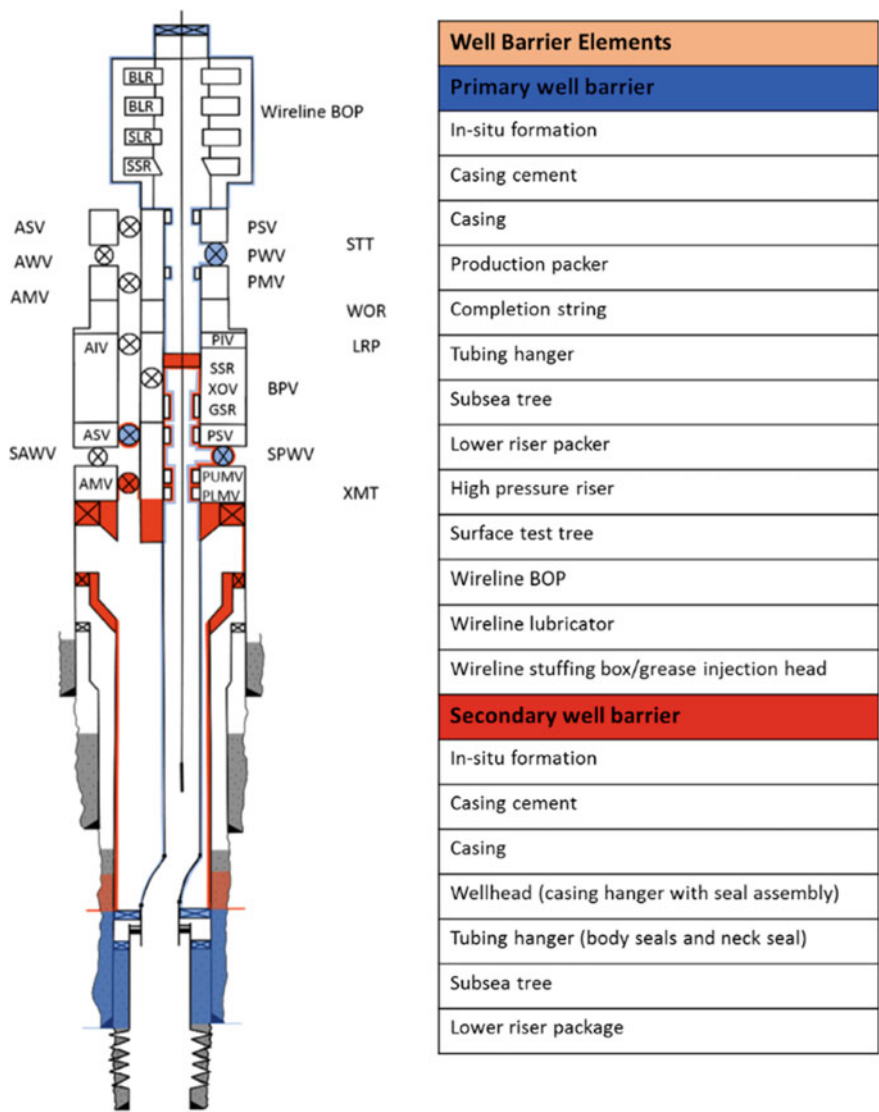


Fig. 2.27 Subsea well with the dual-bore vertical tree

2.9 Special Considerations in Abandonment Design

2.9.1 Control Lines

A control line is a small-diameter hydraulic line used to channel fluid from surface to operate downhole completion equipment such as the SCSSV. Wellhead is designed in such way that provides penetrations for control lines to go through. Figure 2.29 shows

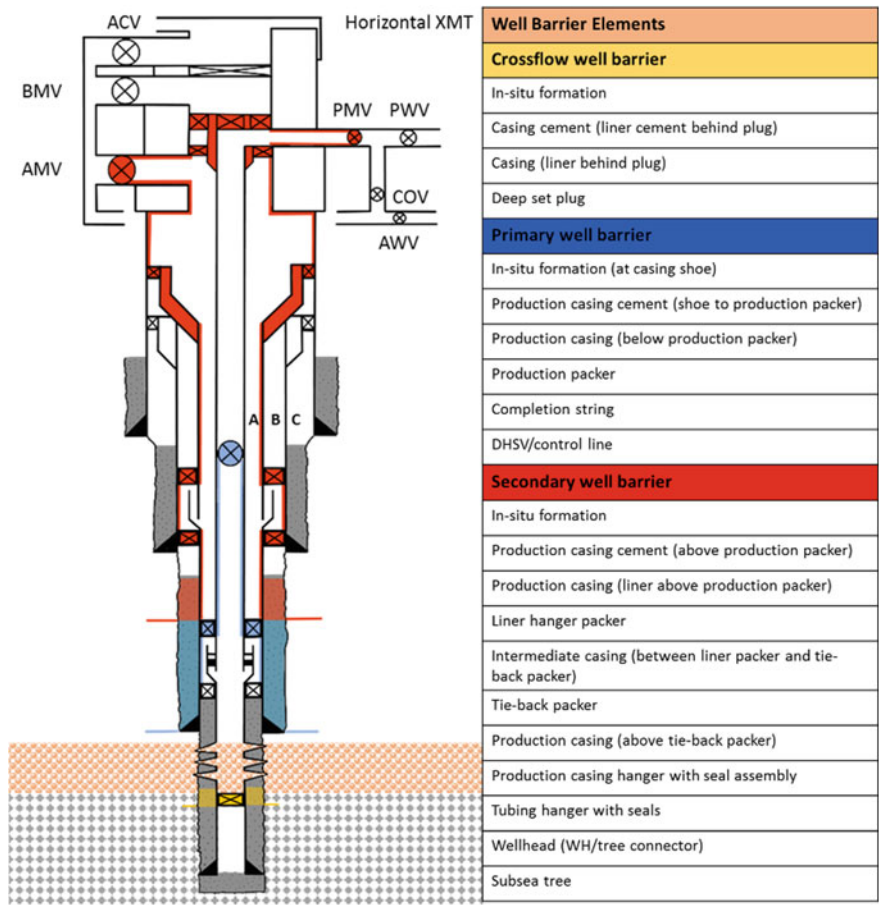
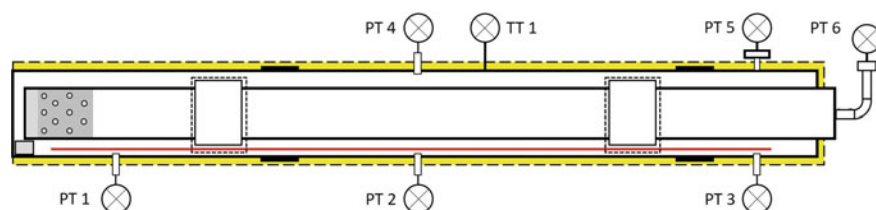


Fig. 2.28 Subsea production well with a horizontal tree



Fig. 2.29 Control lines with and without electrical line



**Fig. 2.30** Full-scale test set-up used for investigating the sealing ability of cement plug when tubing and control lines are left in hole [32]

two different types of control lines; a control line equipped with four small-diameter hydraulic lines, and a control line equipped with two small-diameter hydraulic lines and one conductor line (electric line to the right). Two major concerns exist regarding control lines that persuade engineers to plan for control line retrieval; flow potential of hydraulic line(s) and quality of the bonding between plugging material and surface of the control line. During cement plug placement, a variety of fluids are pumped and each has its own function. These fluids adhere to the surface of downhole equipment (e.g. control line) and its removal is challenging due to wettability of the control line surface. Therefore, the bonding between the cement plug and the control line surface is a concern.

Nowadays most wells are completed as smart wells, meaning control lines and electric lines are part of the well completion to control *Inflow Control Devices* (ICDs). There are different opinions regarding the risk of leakage or well integrity issues concerning control lines as part of the well barrier envelope. Aas et al. [32] performed a full-scale test on the sealability of annulus cement when tubing is left in hole with control lines. In this study, a 7-in. production tubing and a 9-in. production casing were used in the experiments. Figure 2.30 shows the schematic of the full-scale test assembly used in the study. In this study, a 16.0 (ppg) conventional class G Portland cement displaced a 10.0 (ppg) brine, and then the cement was cured for 7 days. The 9-in. production casing was insulated and the temperature development due to cement hydration was recorded. The maximum temperature was recorded as 75 °C after 1 day of curing. The test assembly was 40 (ft) long and it was inclined 85° while pumping cement and during curing. Cement was allowed to fill in the control line. Then, the sealing ability of the cement plug was investigated by pressure testing. Water was pumped at 725 psi to the A-annulus and 1450 psi to inside of the tubing. Aas et al. [32] observed no leakage through the established barrier.

One of the challenges regarding leaving control lines in hole during P&A is related to placing a plug inside the control lines at the desired depth interval. Control lines have a small diameter (1/8 to 1-in. OD) and the fluid inside ranges from water-based hydraulic fluid to a mixture of this fluid with reservoir fluid including formation water. When plugging material is pumped through control lines, it is contaminated in such a way that pressure testing will show a failure. Different plugging materials (i.e. cements, resins, and silicone materials) have been tested for sealing the annuli of control lines [33]. The compatibility of fluid inside control lines and plugging

material appear to be the key to success and there is an interest for more research on this subject.

### 2.9.2 Well Design

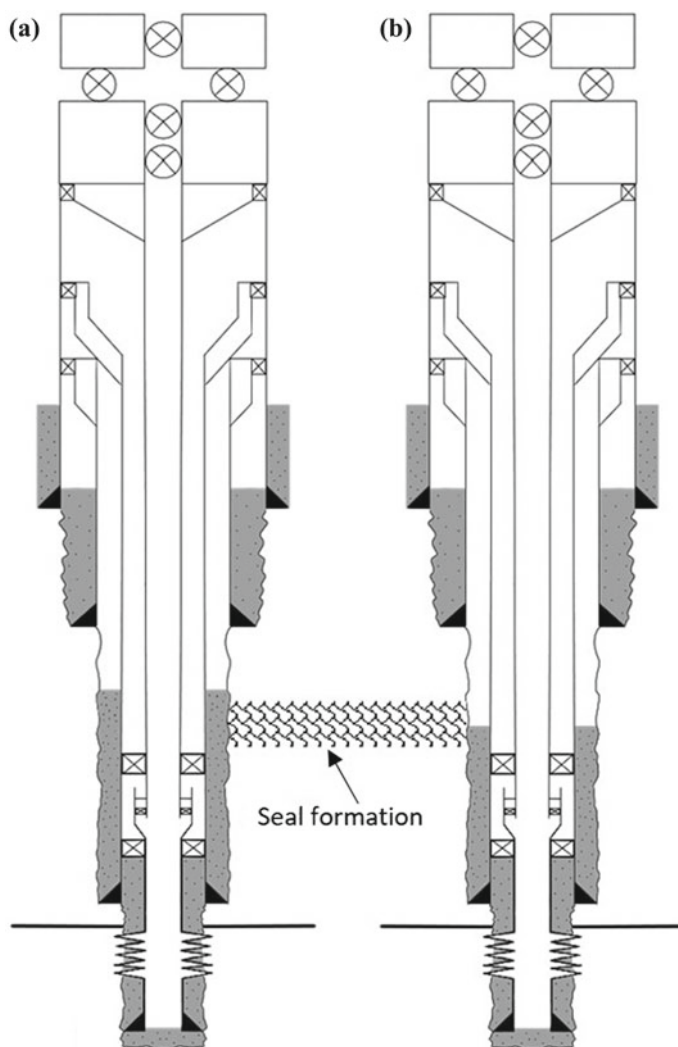
One of the best and most cost effective solutions for P&A is to consider the P&A scenarios during the well design phase. The consideration of the following parameters during well design may strongly influence permanent P&A operations: proper primary cement jobs, depth of TOC, qualification and documentation of primary cement jobs, depth of control lines, and identification of pressure sources in the overburden.

*Primary cement job*—Consider a well with two different well design scenarios, Fig. 2.31. In the first scenario, the well has been designed and constructed in such a way that there is high enough qualified cement across a suitable formation, in the B-annulus, and the primary cement has been qualified and documented, Fig. 2.31a. In the second scenario, the same well has been designed in such a way that there is neither cement in the B-annulus across a suitable formation nor has the cement been qualified and documented, Fig. 2.31b. For the first scenario, if the well does not experience SCP, then the tubing may be retrieved (i.e. if control line is present at the plugging depth) and then a cement plug is placed inside the production casing and across the casing cement. In the second scenario, as there is an uncemented casing, access to the suitable formation requires section milling or other techniques, and then the cement plug can be placed across the formation. The first scenario may take 1 day per plug while the second scenario may take several days per plug due to the required access to the formation.

When there are more than one well to be plugged and abandoned in a field and all of them fulfill the circumstances of the given well in Fig. 2.31a, a common practice may be accepted, which is based on experience. According to the practice, production tubings of two or three wells are retrieved, fully or partially, and their casing cements in the B-annulus are logged. If the casing cements are qualified, then an assumption is made for all the wells in the field. As the wells do not experience any sustained casing pressure, the assumption is that, since the casing cements of the selected wells have been qualified during P&A operations by logging, the casing cement of the other wells are intact and qualified as well. Therefore, tubings are left in hole and the A-annulus and the inside of the production tubings are filled with cement. Furthermore, the new cement plug is tested and if qualified, it is verified and documented. It is necessary to remember that in this scenario, there is no control line in the well barrier envelope.

*Pressure in overburden*—Identification of pressure sources in the overburden during P&A operations is a challenge with a high uncertainty. Therefore, it is recommended to identify and document all pressure sources in the overburden during well construction. Experience shows that unidentified formations with flow potential, in the overburden, can create challenges to qualify permanent barriers below the unidentified influx formation.





**Fig. 2.31** A production well in two different scenarios: **a** high enough qualified cement in the B-annulus, **b** not enough cement in the B-annulus

*Well objectives*—Wells are drilled with different objectives; exploration, delineation, appraisal, development, production, or injection (Table 2.5). When investigating new areas, the interpretation of seismic data helps find areas where there are probable hydrocarbon reserves. The goal of an exploration well is to confirm or reject this hypothesis. In addition, the exploration well gathers the necessary information for a better understanding of the area and its potential future production. As a result of exploration, when the exploration well penetrates an accumulation of petroleum,

**Table 2.5** Well types and their objectives

Well Type	Objectives
• Exploration	• P&A or keeper <sup>a</sup> [34]
• Delineation	• Size of reservoir
• Appraisal	• Reservoir characteristics
• Development/production	• Reservoir drainage
• Injection	• Pressure maintenance • Cutting reinjection • Disposal of unwanted fluids

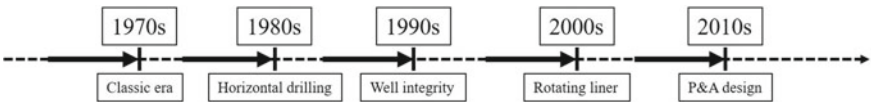
<sup>a</sup>An exploration well intended for completion

a delineation well is drilled for estimating the size of the reservoir and its commercial value. Appraisal wells are drilled for investigating the reservoir characteristics. Development wells are drilled for reservoir drainage and production of petroleum. Injection wells are drilled with different objectives; pressure maintenance, disposal of fluids, and cutting reinjection. Pressure maintenance injection wells are drilled for *Enhanced Oil Recovery* (EOR) and *Improved Oil Recovery* (IOR) processes to increase the recovery factor of reservoirs. Disposal wells are drilled to reinject unwanted fluids (e.g. connate water) produced with petroleum to a non-hydrocarbon bearing formation. Cutting reinjection wells are drilled to dispose of drilling cuttings and contaminated mud in a formation while drilling.

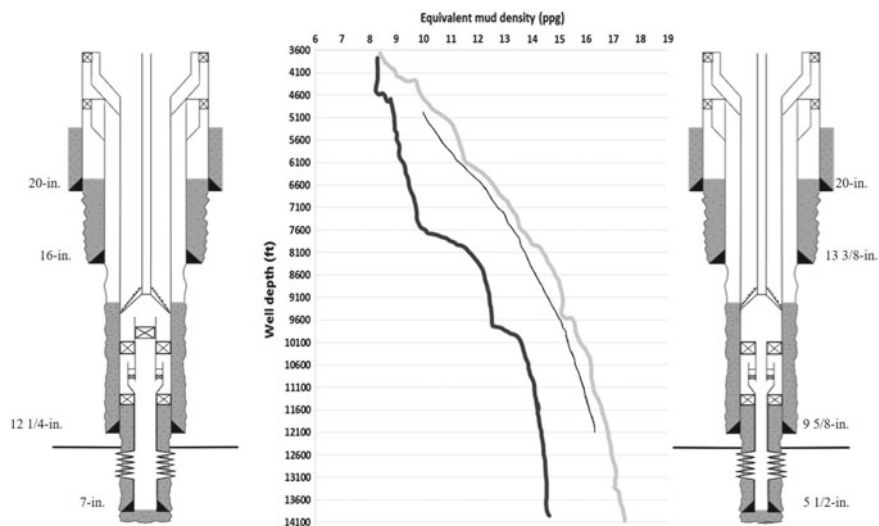
Drilling culture has been influenced by different time regimes and the above-mentioned types of wells have been designed based on the needs over time, and subsequently their design criteria has been changing with regards to the knowledge of engineers. Figure 2.32 shows a timeline for different design criteria eras in well construction. Perhaps from past to 1970s could be called as classic era of well design, 1980s as horizontal drilling and slot recovery era, 1990s as well integrity era, 2000s as rotating liner and the last decade could be marked as era of P&A in well design and it has been accelerated due to Macondo incident. There is an indisputable subject which has been focused continuously over time, and that is cement and its properties.

There have been eras where wells were drilled and completed without comprehensively considering their future P&A. Therefore, each type of these wells which have been drilled over decades, have their unique specific well design and need to permanently be plugged and abandoned using a best practice.

*Pore pressure and fracture pressure profiles*—In a pressure depleted reservoir, the reservoir pore pressure will be lower than the initial pressure and the fracture pressure will also be reduced. Consequently, the margin between pore pressure and



**Fig. 2.32** Timeline showing different eras for focusing on different subject



**Fig. 2.33** Effect of annular space on ECD and margin between pore pressures and fracture gradient profiles

fracture pressure gradients will be smaller. In P&A operations, having a narrow margin between pore pressures and fracture gradient profiles can be a challenge and limiting factor, particularly in deep-water offshore wells. This narrow margin results in limitations with respect to the selection of hole cleaning fluid systems, swarf/cutting removal, cement design and its placement, etc. Compare a scenario where a 5-in. drillpipe as a working string is performing section milling in a 9 5/8-in. casing with another scenario where the same drillpipe is conducting section milling on the same well at the same depth but milling a 12 1/4-in. casing, Fig. 2.33. As a result of different pressure drop in the annulus, the *Equivalent Circulating Density* (ECD) will change and the exposed formation may be fractured.

**Example 2.2** Consider a 5-in. drillpipe is performing section milling of a 9 5/8-in. casing at 8000 (ft) True Vertical Depth (TVD) with a mud weight of 10.8 (ppg) whereas the annular pressure loss is 460 psi. Assume that the pore pressure and fracture pressure at 8000 (ft) are 10.2 (ppg) and 11.7 (ppg), respectively.

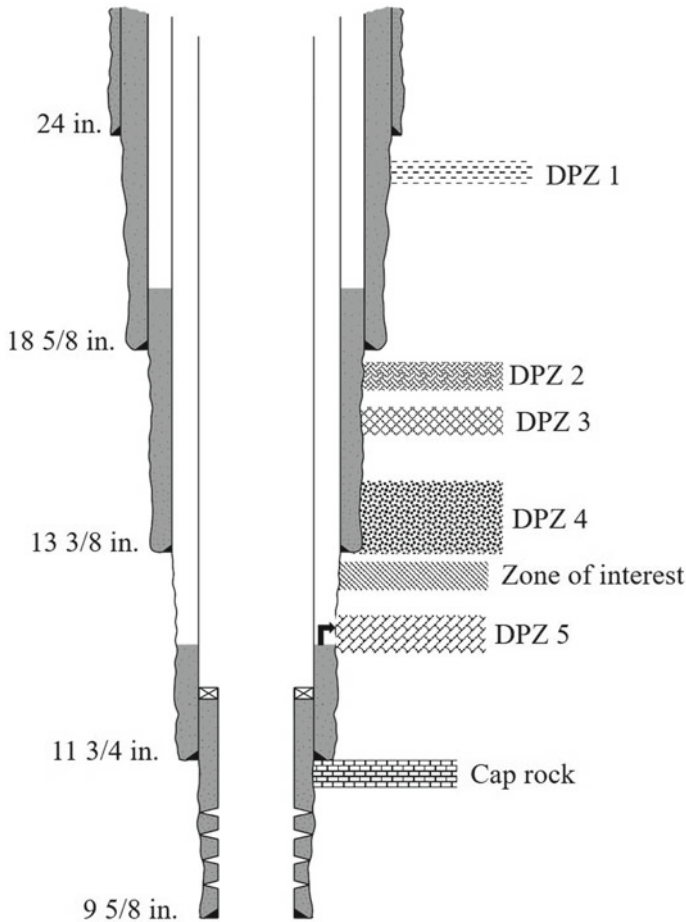
- Does the downhole pressure fracture the formation?
- Consider the same situation where the casing is 12 1/4-in. and the annular pressure loss is 340 (psi). Does the downhole pressure fracture the formation in this scenario?

### Solution

$$ECD (ppg) = mud\ weight (ppg) + \frac{annular\ frictional\ pressure\ loss (psi)}{0.052 \times TVD (ft)}$$

- (a)  $ECD = 10.8 + \frac{460}{0.052 \times 8000} = 11.9 \text{ ppg}$   
 The ECD is higher than the fracture gradient and induces fractures.
- (b)  $ECD = 10.8 + \frac{340}{0.052 \times 8000} = 11.6 \text{ ppg}$   
 The ECD is slightly lower than fracture gradient.

**Casing seats**—It is the set point of the end of casing and generally it is based on consideration of pore-pressure gradients and fracture gradients of formations to be drilled. Casing seat is normally placed in an impermeable and stable formation. Casing seat depth (also known as casing setting depth) can influence P&A operational time; therefore, it should be considered and selected properly during well design with regards to future P&A of the well. The example shown in Fig. 2.34 illustrates the situation where a lost-circulation zone (DPZ 5) leads to a very low height of TOC for the production casing. As the intermediate casing string has the right casing-seat



**Fig. 2.34** Relationship among casing seat and permanent barrier establishment

depth, an interval above the lost-circulation zone is provided to establish primary and secondary barriers for the reservoir. But if the casing seat for the intermediate casing was deeper, then barrier establishment for the reservoir could be more challenging.

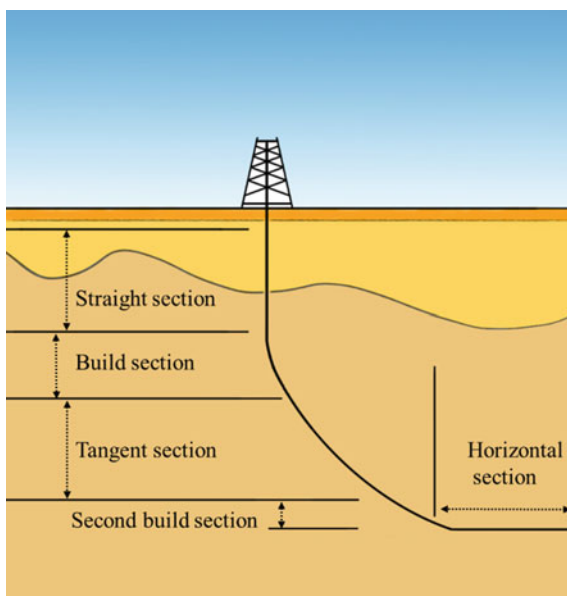
### 2.9.3 Well Schematic

A well schematic is suggested to be produced and updated on a daily basis, during P&A operations. It shows the actual phase of each well with its status. In this manner, it becomes clear to a wider audience if the P&A operation is falling behind, or is ahead of schedule, and if necessary, extra resources can be applied.

### 2.9.4 Horizontal Wells

A well with an inclination of generally larger than  $85^\circ$  is called a horizontal well. The horizontal section of a horizontal well is in the pay zone and is not normally an interesting interval for P&A. The build and tangent sections are important, Fig. 2.35. It is recommended to establish the permanent barrier as close as possible to the cap rock and across a suitable formation. Therefore, the build and tangent sections are interesting intervals; however, the high angle of these sections imposes some serious challenges. Performing wireline operations, hole cleaning, and cement plug

**Fig. 2.35** Different sections of a horizontal well



placement at high angles (usually more than 65°) are some of the challenges to be considered, impacting the operation time and associated risks.

2.9.5 High-Pressure High-Temperature Wells

Over the years and across companies, definitions of *High-Pressure High-Temperature* (HPHT) wells have varied and no industry-wide standard defines HPHT conditions. The *American Petroleum Institute* (API) attempted to define HPHT terminology by publishing guidelines for equipment used in HPHT operations. According to the API Technical Report 1PER15K-1, a well having pressure higher than 15000 psi is defined as a HP well; and a well having temperatures higher than 350 °F is defined as a HT well [35]. However, NORSOK Standard D-010 [1] defines a well as a HP well when the shut-in pressure is exceeding 10000 psi and a well as a HT well when the static bottomhole temperature is higher than 300 °F. Figure 2.36 shows a proposed system for the classification of HPHT conditions for well-service-tool components. As HPHT conditions impose a unique situation, particular considerations should be taken during the design and operational phase of P&A.

Usually HP conditions dictate the use of larger BOPs. A larger BOP means limited space and handling capacity for offshore wells, more fatigue stresses on the wellhead, and more time consumed function testing the BOP. In addition, HP wells impose the need for a large increase in mud weight to control formation pressure; however, hydrostatic pressure may then approach fracture pressure.

For high temperature conditions, the impact of thermal expansion of drilling fluid on kick tolerance, effect of high temperature on equipment performance, and limited

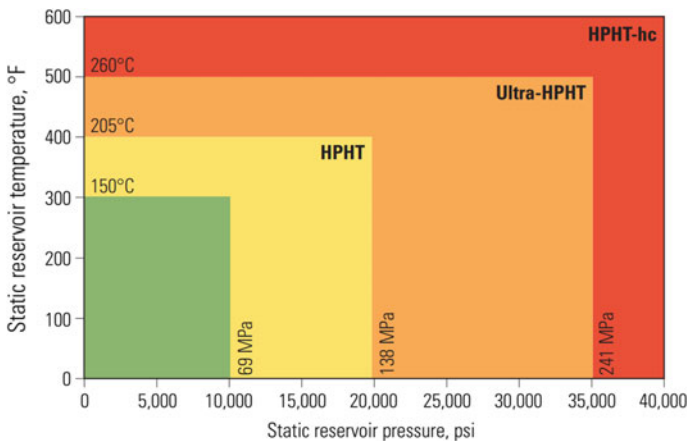


Fig. 2.36 A proposed HPHT classification system [36]

range of suitable plugging materials need to be considered during abandonment design.

More challenging conditions exist where high pressure and high temperatures are present together. Achieving adequate hydrostatic pressure while avoiding fracturing the formation is a challenge for the HPHT mud engineer. Wellbore instability, in milled sections, in high temperature and highly-depleted reservoirs is another challenge to be considered. Establishment of a cross sectional barrier (see Fig. 2.43) may require section milling and where a pressure depleted, and high temperature reservoir is the subject, there is the risk of wellbore instability due to changes of thermal elasticity of porous medium. Subsequently, leading to narrowing the mud density window. The reduced fracture gradient and drilling fluid loss are challenges which are rooted in pore pressure depletion, reduction of wellbore temperature, and drilling fluid osmosis in plugging and abandoning high temperature and highly-depleted reservoirs [37].

In HPHT and deep-water conditions, considerable temperature variations are seen in the transition from circulating conditions to geothermal gradient conditions during static periods. Generally, the milling interval of a wellbore experiences cooling as cold mud is pumped down the drill string. The upper part of the wellbore experiences heating as warm drilling fluid is circulated up, especially during hole cleaning. When the circulation is stopped, the temperature profile will, by heat conduction, return to geothermal conditions and subsequently, heat the mud in the milling interval and cool the mud in the upper part of the wellbore. Heating and cooling of mud in lower part and upper part of the wellbore in static conditions counteract each other. If the heating process dominates the wellbore condition, then mud experiences a thermal expansion and a gain in the mud pits will be observed. Consequently, hydrostatic pressure of the mud column drops and well control will be a concern.

Cement plug placement of HPHT wells requires a higher cement density and the situation imposes higher ECDs and therefore, low pumping rates are preferred. Subsequently, due to a low pumping rate which may change the flow regime (i.e. from turbulent to laminar), the mud displacement may be inefficient. In addition, a low pumping rate requires a slurry design with longer thickening times which needs more chemicals as retarders at high temperature conditions as high temperature accelerates the hydration process. As a rule of thumb, the more retarders used the more side effects on properties of the cement [38, 39]. So, HPHT wells require special consideration during abandonment design.

### ***2.9.6 Shallow Permeable Zones***

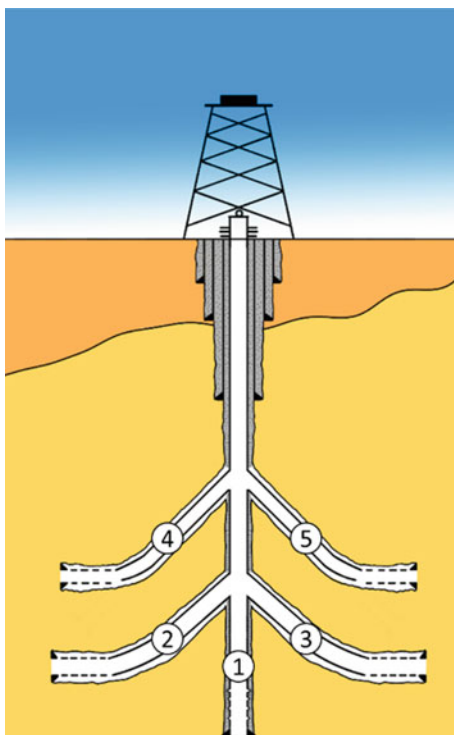
Identification and sealing production potentials in the overburden formation are assessed during abandonment. Shallow sources include shallow gas, coalbed methane, and water bearing zones. Although protection of the surface environment from any contamination caused by an abandoned well is the goal of P&A, protection of drinking water sources (surface water and ground water) increases the importance

of permanent P&A. So, identification of shallow potentials during the initial life-cycle of wells (drilling) and P&A is necessary. These potentials need to be sealed properly, assessed, and finally documented.

### 2.9.7 Multilateral Wells

Where a well has more than one branch radiating from the main borehole, the well is called *multilateral well*. Multilateral wells are an evolution of horizontal wells. Permanent abandonment of multilateral wells requires a detailed study to design the required number of permanent plugs per borehole. If possible some of the boreholes may be regarded as one borehole to reduce the number of plugs to be installed, Fig. 2.37.

**Fig. 2.37** Cased and cemented main bore with openhole multilaterals





2.9.8 Slot Recovery Sidetracks

Some regulators require, prior to slot recovery or sidetracking, the original wellbore to be permanently plugged and abandoned, Fig. 2.38. The permanent barrier can be a crossflow barrier or primary and secondary permanent barriers depending on the pressure regimes, formation strengths and available window between the formations. However, if at the time of sidetracking a permanent abandonment of the original borehole is not feasible, the primary and secondary temporary barriers need to be designed and established for the intended period. During the abandonment design, all of these original boreholes need to be mapped.

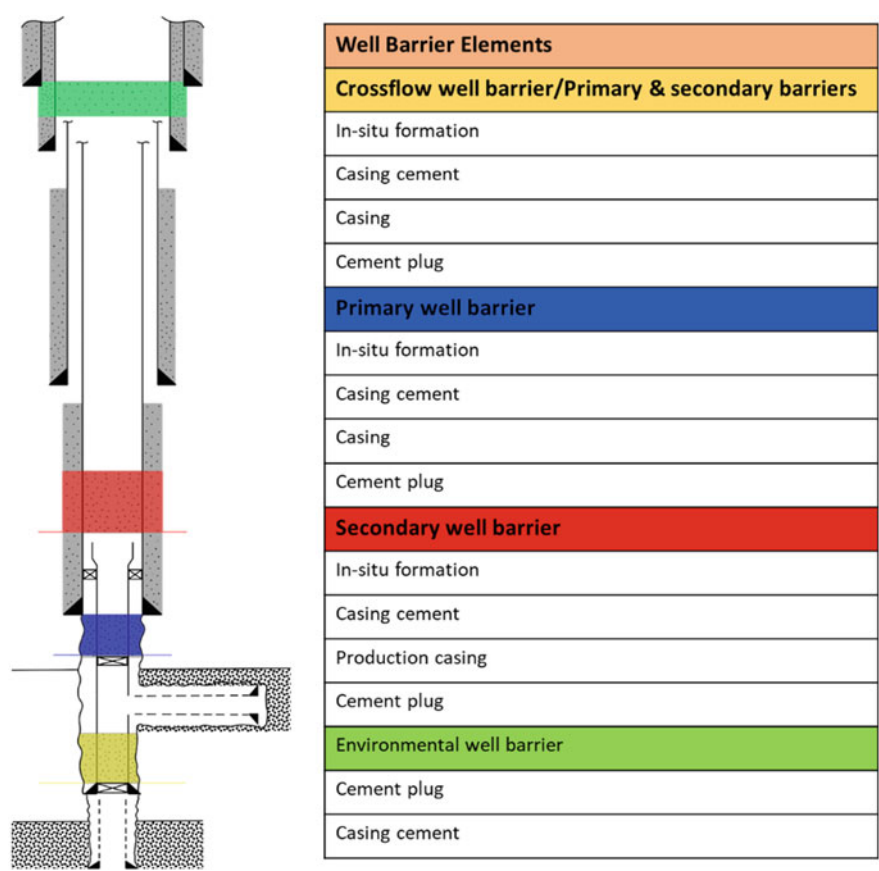
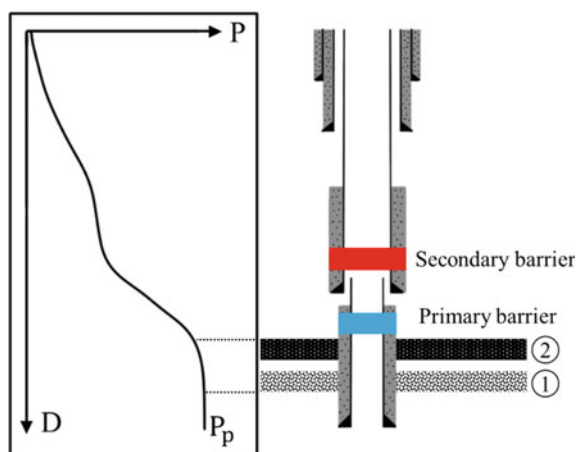


Fig. 2.38 Permanent abandonment, multi-bore with slotted liners

**Fig. 2.39** Permanent plug and abandonment of multiple reservoirs with the same pressure regime



### 2.9.9 Multiple Reservoirs

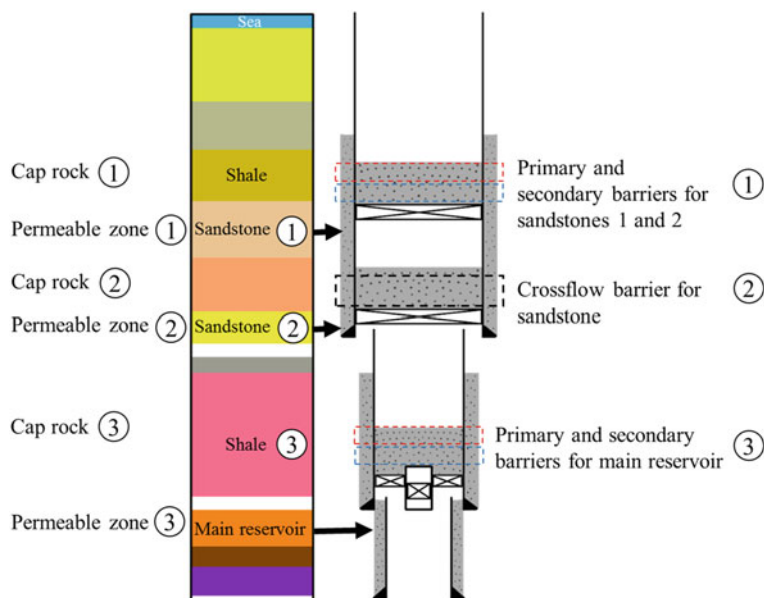
Multiple reservoir zones located within the same pressure regime can be regarded as one reservoir. In such a scenario, primary and secondary permanent barriers are established above the upper potential, Fig. 2.39. If potentials are in the same pressure regime but crossflow is not acceptable, then a barrier can be established between the potentials, Fig. 2.40. In this scenario, the crossflow barrier may be regarded as a primary barrier for reservoir 2 and the primary permanent barrier for reservoir 3 is regarded as secondary permanent barrier for reservoir 2, Fig. 2.40. In this case, the reservoir 2 has three barriers including the crossflow barrier. A combination of permanent plugs for different potentials, which are in the same pressure regime and crossflow is acceptable, saves time and reduces costs. However, risk analysis needs to be performed to investigate the long-term consequences.

When the potentials have different pressure regimes and crossflow is not acceptable, each potential is secured with two barriers, primary and secondary barriers, Fig. 2.40.

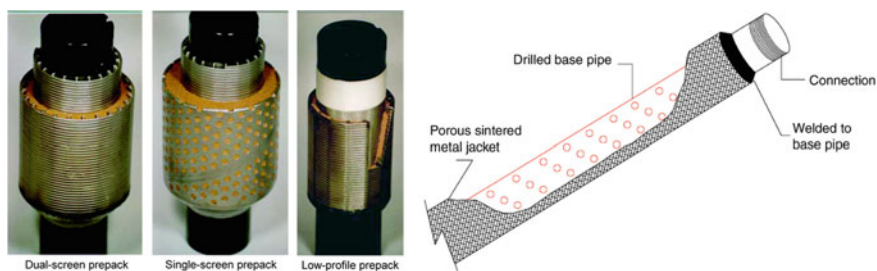
### 2.9.10 Slotted Liner

The *screen* or *slotted liner* is a mechanical device which may contain gravel-pack sand in the annular space between it and the casing wall or openhole, Fig. 2.41.

Reservoirs or zones completed with a slotted liner or screen should be plugged above the slotted liner or screen. One of the reasons is that screen or slotted liner acts as filter for plugging materials. Consider a cement slurry which is pumped across a screen, the screen acts as a filter and drains the water such that hydration of cement



**Fig. 2.40** Two flow potentials; same pressure regime but crossflow is not permitted, different pressure regimes with no permitted crossflow

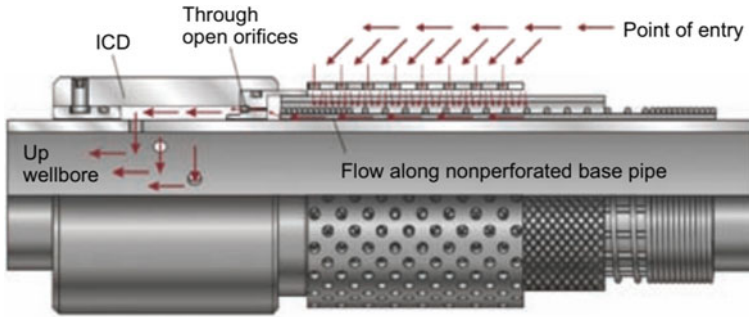


**Fig. 2.41** Types of prepacked screens. (Courtesy of Baker Hughes)

would not be completed and consequently, poor chemical and physical properties of the cement plug would be expected.

### 2.9.11 Inflow Control Device

An inflow Control Device (ICD) is a surface controlled device which is installed as a part of well completion to help to optimize production by reducing water inflow contribution. Usually, during completion multiple ICDs are installed along the well,



**Fig. 2.42** Flow path of a typical ICD [40]

in horizontal sections. ICDs are frequently used with sand screens and in open-hole completions. ICDs allow controlled inflow but prevent outward flow, Fig. 2.42. Therefore, pumping cement slurry through ICDs is a challenge.

### 2.9.12 *Tubing Left in Hole*

Retrieval of production tubing is a time consuming and costly operation. Therefore, leaving the tubing in hole is often a desired option. If the production tubing is in a good condition, it can be used as work string for cementing. However, mechanical strength of a tubing for being used as work string should be analyzed [32].

### 2.9.13 *Hydrocarbons in the Overburden*

It is important to identify all sources of inflow in the overburden, run a risk analysis, and if necessary secure them by establishing of barriers. Due to uncertainty of old data, it is necessary to use data obtained from recent wells drilled in the same reservoir or field, to identify shallow sources of inflow. Retrieving the production tubing and logging behind production casing and intermediate casing may be necessary as these sources can contaminate ground water, soil or the marine environment. Hydrocarbons in the overburden may exist naturally or form due to well integrity issues.

## 2.10 Requirements for Designing Permanent Barriers

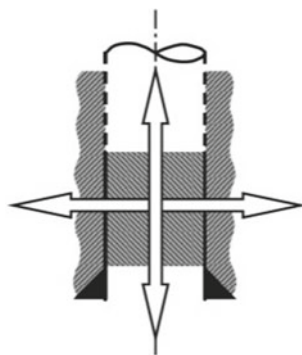
### 2.10.1 Well Cross Sectional Barrier

A permanent well barrier shall extend across the full cross section of the well while sealing all annuli both vertically and horizontally, Fig. 2.43. It is placed across a suitable formation; an impermeable formation with sufficient strength to hold the maximum anticipated pressure from the source of inflow. The barrier is known by different names such as *cross-sectional barrier*, or *formation-to-formation barrier*.

### 2.10.2 Plug Setting Depth—Formation Integrity

The adjacent formation to the permanent plug shall be capable of holding the maximum anticipated pressure from the source of inflow. The maximum anticipated pressure is either the original (initial) reservoir pressure for reservoirs with strong aquifers or an estimated final pressure that is below original reservoir pressure. The estimated final reservoir pressure is defined in a time interval and obtained through simulations. The maximum anticipated pressure is important for calculating the *Minimum Setting Depth of Plug* (MSD). The minimum setting depth of plug is the shallowest depth where the formation withstands the maximum anticipated pressure without being fractured. As the secondary plug is a backup to the primary plug, the MSD is the shallowest depth where the top of the secondary permanent plug can be placed. It is a common practice to place the plug as close as possible to the source of inflow. The MSD is estimated by using either pressure-gradient curves or a fluid gradient concept. The gradient curve method is a quick and reliable estimation for finding the MSD but the fluid gradient concept can also be used when several leak-off data are available.

**Fig. 2.43** Cross sectional barrier seals all the annuli.  
(Reprint from NORSOK D-010)



2.10.2.1 Minimum Setting Depth—Gradient Curves

In this method, initial pore pressure, fracture pressure, minimum horizontal stress, and overburden pressure curves are plotted. Then, a gas gradient line is drawn from the reservoir pressure towards the surface. For drawing the gas gradient line, it is necessary to know the final reservoir pressure and then subtract the hydrostatic effect of the gas column. The intersection of the curve for a closed well filled with gas and the minimum horizontal stress curve is the MSD, (see Fig. 2.44). The selection of final pressure is a crucial decision whereby selection of a lower value shifts the gas column curve to the left and consequently the MSD will be closer to the surface. However, when the reservoir builds up pressure, the adjacent formation to the plug

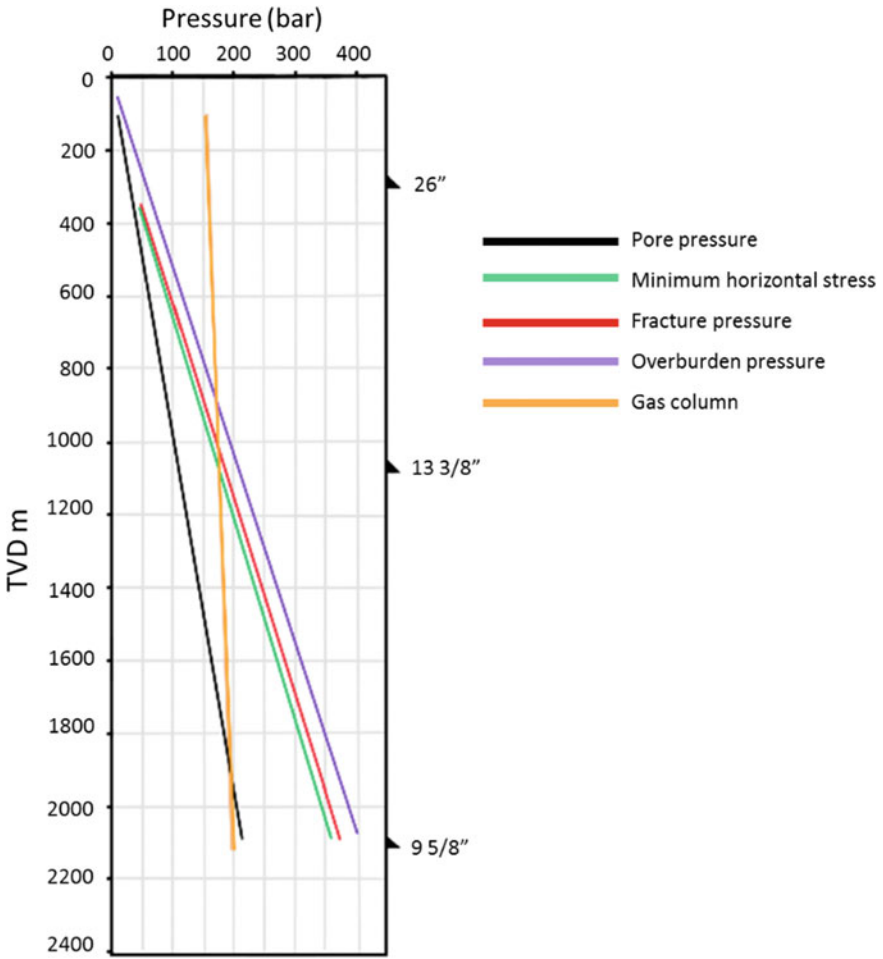


Fig. 2.44 Pore pressure and fracture pressure gradient curves of a platform well

is not able to hold the pressure and subsequently fractures. Selection of a higher reservoir pressure shifts the gas column to the right and MSD will be further away from the surface. As a result, the window for finding the appropriate interval for plug to be placed is limited.

**Example 2.3** The following gradient curves, Fig. 2.45, have been reported for a well. Based on the given information estimate the minimum setting depth for the plug and propose an interval for the plug placement.

**Solution** The gas gradient curve should be plotted and extended to overburden pressure. The intercept point between the gas gradient curve and the minimum horizontal stress curve is the MSD of secondary plug. It means that the top of secondary barrier can be up to the depth of interception. However, it is recommended to install the permanent barriers, primary and secondary, as close as possible to the source of inflow.

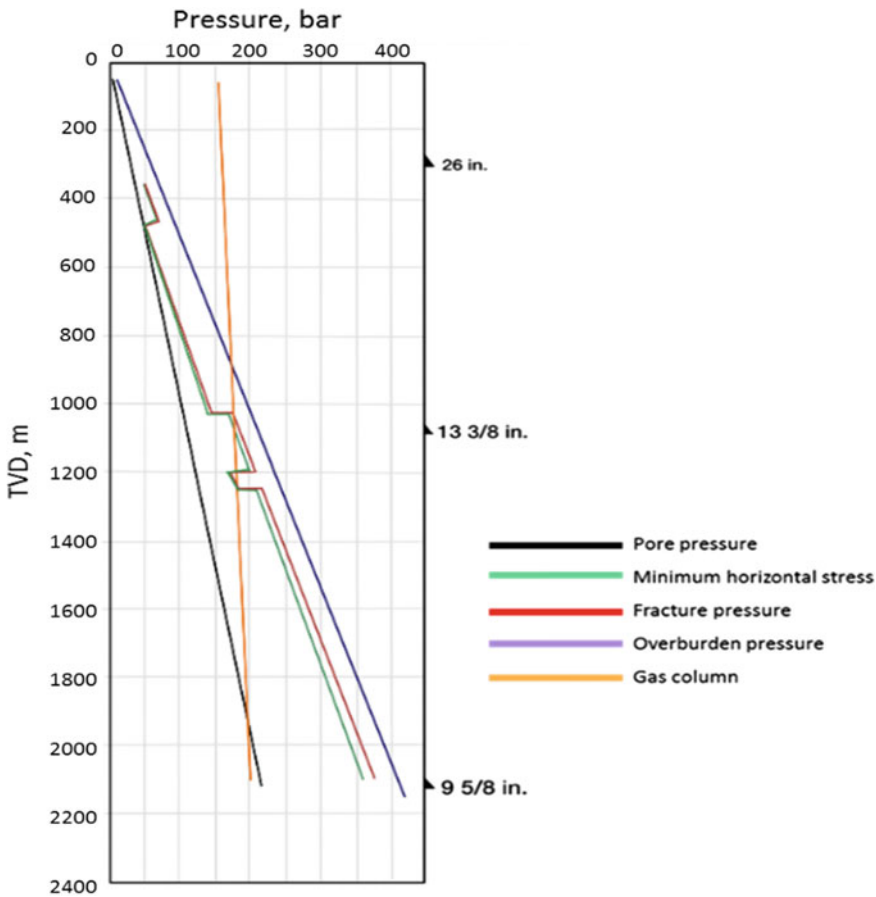


Fig. 2.45 Pore pressure—Fracture pressure gradient curves

In this way, in case of barrier failure, if permanent barriers are not qualified, there will be a window left to install new barriers.

### 2.10.2.2 Minimum Setting Depth—Fluid Gradient

In this method, the intersection between the fracture pressure and gas column is obtained mathematically. The MSD is the unknown parameter while the final reservoir pressure, fracture gradient, fluid gradient, and TVD of the reservoir are known parameters. The MSD is given by:

$$P_{FP} - P_g \times (H - h_{MSD}) \leq \frac{12}{231} \times P_{frac.} \times h_{MSD} \quad (2.5)$$

$$h_{MSD} \geq \frac{P_{FP} - P_g \times H}{\left(\frac{12}{231} \times P_{frac.}\right) - P_g} \quad (2.6)$$

whereas  $P_{FP}$  is the final reservoir pressure (psi),  $P_g$  is the gas gradient pressure (psi/ft),  $H$  is the TVD of reservoir (ft),  $h_{MSD}$  is the minimum setting depth (ft), and  $P_{frac.}$  is the fracture pressure gradient (ppg).

**Example 2.4** A platform well was drilled in the NCS in 1999 and the initial reservoir pressure was 2915 psi. The well is an oil producer with a fluid gradient of 0.32 (psi/ft). The reservoir is supported with a strong aquifer and the current reservoir pressure is 2755 psi. An average fracture gradient from leak off test is estimated to be 10.0 (ppg). The production casing shoe was placed at 6050 (ft) TVD and the cap rock thickness is 200 (ft) TVD. Calculate the minimum setting depth for primary and secondary barriers. Assume a gas gradient of 0.1 (psi/ft).

**Solution** This question shows how the gas presence can create a small window for placing the barrier.

The question mentions that the reservoir is supported by an active aquifer, which means that the reservoir pressure can build up to initial reservoir pressure. If we assume that the reservoir is under saturated, then oil is present and oil gradient is used for calculations. By using Eq. (2.6):

$$\begin{aligned} h_{MSD} &\geq \frac{P_{FP} - P_g(H)}{\left(\frac{12}{231} \times P_{frac.}\right) - P_g} \\ h_{MSD} &\geq \frac{2915 - 0.32 \times 6250}{\left(\frac{12}{231} \times 10\right) - 0.32} \\ h_{MSD} &\geq 4575 \text{ (ft) TVD} \end{aligned}$$

Now consider that the reservoir is a saturated reservoir, which means gas is present in the wellbore.



$$h_{MSD} \geq \frac{2915 - 0.10 \times 6250}{\left(\frac{12}{231} \times 10\right) - 0.10}$$

$$h_{MSD} \geq 5452 \text{ (ft) } TVD$$

It means that the window to install both primary and secondary barriers is smaller.

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