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School of Geology

MSc in Hydrocarbon Exploration and Exploitation

WELL COMPLETION FOR HYDROCARBONS PRODUCTION AND PRODUCTION LOGGING

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by

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WELL COMPLETION FOR HYDROCARBONS PRODUCTION AND PRODUCTION LOGGING

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To my family

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On the very outset of this report, I would like to extend my sincere & heartfelt obligation towards all my friends who have helped me in this endeavor.

Last but not least I would like to acknowledge with gratitude, the support of my family – my parents, Asterios and Anna; my sister, Evdokia; who kept me going, because this effort would not have been possible without them …

Iraklis A. Mantziokas

ABSTRACT

The objective of this Master Thesis is to present fundamental values related to the well completion. More specifically, this study will be useful as a learning and reference guide-tool from the drilling and reservoir, to completion and production engineers' technical aspects.

Well Completion, refers to the operations that prepare a well for production (or injection). These operations include preparing the reservoir to wellbore interface, begin by first installing the conductor pipe and finish by installing the production tubing and the structural system and equipment, which is necessary for the production of the hydrocarbons. However, the well completion' specifics are very variable, depending on the geological formation and operator.

The present MSc thesis, defines the well architecture which is a fundamental aspect of well design, from the onshore activities, to smart well technology in Deepwater field. Furthermore, the concept of well completion engineering and equipment for hydrocarbons production is presented, and the different types of production logging. Studying and characterizing the reservoir can play a vital role in improving and maximizing its performance and production, in general.

So, to assist with the allocation of production to different zones, and to diagnose production problems such as leaks or crossflows, production logging techniques are developed. A review of this technology, is therefore provided in this thesis, in order to gain a detailed procedure and measurement understanding of the different production logging tools.

Thus, the importance of proper analysis is necessary to be illustrated in well completion for hydrocarbons production and production logging.

ΠΕΡΙΛΗΨΗ

"Η Μ.Δ.Ε. επιχειρεί να καλύψει βασικές έννοιες σχετιζόμενες με την ολοκλήρωση των γεωτρήσεων [well completion] και να παρουσιάσει συγκεντρωτικά τις δραστηριότητες των μηχανικών ταμιευτήρων, μηχανικών γεωτρήσεων, μηχανικών πετρελαίου και μηχανικών παραγωγής. Η ολοκλήρωση μιας γεώτρησης ξεκινά με την τοποθέτηση των σωλήνων επένδυσης σε επαφή με τους γεωλογικούς σχηματισμούς και τελειώνει με την εγκατάσταση του εξοπλισμού παραγωγής και των εγκαταστάσεων επιφανείας. Οι λεπτομέρειες της ολοκλήρωσης ενός φρεατίου είναι πολύ μεταβλητές, και εξαρτώνται κυρίως από τους γεωλογικούς σχηματισμούς χωρίς εντούτοις να παραγνωρίζεται και η εμπειρία των χειριστών.

Στη Μ.Δ.Ε. αρχικά παρουσιάζεται ο σχεδιασμός της ολοκλήρωσης μιας γεώτρησης ξεκινώντας πρώτα από τις χερσαίες γεωτρήσεις και καταλήγοντας στα πολύ εξελιγμένα υποθαλάσσια, 'έξυπνα' φρεάτια, βαθέων υδάτων. Παρουσιάζονται όλες οι διαδικασίες ολοκλήρωσης, οι διάφοροι τύποι εξοπλισμού για την ολοκλήρωση μιας γεώτρησης και την παραγωγή υδρογονανθράκων, καθώς και οι μέθοδοι καταγραφής των παραμέτρων παραγωγής [production logging]. Η μελέτη και ο χαρακτηρισμός του ταμιευτήρα κατά την παραγωγή, μπορεί να παίξει σημαντικότατο ρόλο στη βελτίωση της απόδοσης των ταμιευτήρων και γενικότερα στη βελτιστοποίηση της παραγωγής. Οι μέθοδοι καταγραφής των παραμέτρων της παραγωγής βοηθούν στον διαμερισμό της παραγωγής από διαφορετικές ζώνες/ορίζοντες, καθώς και στη διάγνωση προβλημάτων, όπως διαρροές ή crossflows. Στη Μ.Δ.Ε. παρουσιάζονται όλοι οι φωρατές για την εκτέλεση του production logging, με λεπτομερή περιγραφή του τρόπου λειτουργίας αυτών. Έτσι, καταδεικνύεται η σημασία της σωστής ανάλυσης τόσο για την πλήρη και ορθή ολοκλήρωση μιας γεώτρησης όσο και για τη διαδικασία καταγραφής κατά την παραγωγή".

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1. WELL COMPLETION

1.1 Introduction

The word 'completion' itself implies the conclusion, of a borehole that has just been drilled. Therefore, completion is the link between the borehole drilling and production phase. (***Perrin et al. 1999***).

Well completion is the most important phase of a well's life. In petroleum engineering, it includes the activities and methods of preparing a well for production or injection, and irrespective of whether it is offshore or onshore well, its basics remain the same. This important evaluation is considered one of the most remarkable parts of the preparation for oil production.

In general, completion involves all of the operations planned to make the well produce, in particular connecting the borehole and the pay zone, equipping the well, putting it on stream and assessing it. The concept of well completion engineering has been gradually enriched, perfected, and updated by the progress of science and technology. For this reason, completion is a combination of mathematics, geology, engineering chemistry, mathematics, physics, and practical hands-on well site experience.

Process Steps	Responsible Party
Create a reservoir model	Geologist and reservoir engineer
Specify reservoir pressures and temperatures	Reservoir engineer
Estimate well rates and ultimate recovery	Reservoir engineer
Identify any special issues	All involved
Develop a completion plan	Completion engineer
Estimate the completion cost	Completion engineer
Approve the rig company capabilities	Completion superintendent
Select service providers	All involved

Figure 1: Well Completion Process (*Leffler et al. 2003*)

Even before the drilling phases finishes, the geologist and reservoir engineer have raw data to help them work on the first three steps in the well completion process, defining how the reservoir behaves. Their information, plus, input from the petrophysical engineer, the geophysicist, and others become the fodder for a completion plan.

When a new hole is drilled up to the target level and drill-stem testing and well logging operations are completed, the results are analyzed from the corporate management to choose whether or not to finish the well**,** as a producing well or as a dry hole to plug it. The well will probably be plugged and abandoned as a dry hole, if the evidence indicates that no oil or gas is present, or they are not present in sufficient quantities to allow for the recovery of drilling, completion and production costs and provide a profit on investment. If on the other hand, evidence indicates the existence of adequate amounts of oil or gas to permit the recovery of these costs and to provide the company with a profit, an attempt will be made to complete the well as a producer (***Hossain & Al.Mayed. 2015***).

Well completion refers to the operations that prepare a well for production (or injection). These operations include preparing the reservoir to wellbore interface to the required specifications, as well as perforating and stimulating as required, installing the production tubing and associated down hole equipment ('the completion string') and installing the surface production wellhead. The design of a completion string should be established in common by reservoir, production and well engineers according to the reservoir parameters, expected performance of the well mechanical considerations and production operations requirements and well intervention policy.

Wells are completed with equipment at different levels of the borehole that allow the measurement of liquid and gas content, as well as the remote control to enable shutting production from certain areas of the borehole. Well completion operations aim to ensure effective communication between reservoir and wellbore, optimized well performance throughout field life, minimum well workover/intervention requirements and well mechanical integrity and safety at all times. In specific reservoir cases, completion can also allow to produce selectively multiple reservoirs or layers, isolate layers producing substantial water or gas and control sand influx from non-consolidated formations (***Kassinis 2015***).

The explanation of well completion could be interpreted by three crucial requirements of any completion such as i) safety of hydrocarbon production or injection, ii) economically efficient and iii) reliable. It means a large percentage of expenditure on the development of an oil or gas field. The well needs to be 'completed' correctly, so that maximal productiveness of the field may be obtained. So, the term 'well completion' is defined as the methods by which a newly drilled well can be finalized so that reservoir fluids can be controlled and thereafter to bring the well into production which satisfies the operator's objectives for the field development.

The methods of well completion are the following:

- A method of bringing satisfactory communication between the reservoir and the borehole.
- Installing the tubulars (the last string of casing and the production tubing).
- Perforating the formation if necessary.
- Treating the production formation if necessary.
- Installing the wellhead.
- Installing the safety devices and equipment which will automatically shut in the event of a blowout.

1.2 History and Evolution of Well Completion

As the understanding of reservoir and production performance has evolved, the history of well completion is directly related to the history of oil discovery as mentioned in ***Table 1.*** Early wells, commonly called barefoot completions, were drilled in hollow areas which were sufficiently consolidated to prevent caving. The first wells were produced by bailing.

1300	Macro Polo reports wells on shore of Caspian Sea	1922	Simple hole-survey tools introduced
1814	First well to produce oil - 475 ft.	1925	API addresses tool joint threads
1822	Rudimentary art of drilling established	1926	First electric submersible pump used
1861	First recorded blowout	1927	First electric log run (Schlumberger)
1863	Screwed casing joints developed	1930	Well depths exceed 10,000 ft.
1880	Standardization of casing begins	1932	First gravel pack job
1882	Straddle rubber wall packer developed	1933	First gun perforation job
1890	First extensive casing program	1943	First subsea completion (Lake Erie, USA)
1895	Henry Ford builds the first commercial automobile	1958	Wireline retrievable SSSV developed (Camco)
1905	Casing cemented for the first time	1958	Thru-tubing workover techniques developed
1910	Drillpipe tool joints introduced	1960	Cement bond log developed
1911	First Gas Lift device	1963	First coiled tubing job (Bowen)
1913	First dual completed well	1967	Computerized well data monitoring developed

Table 1: History of Well Completion (*Hossain & Al.Mayed 2015*)

When deeper wells were drilled into high pressure formations, the difficulties associated with surface water prompted the need of a casing or conductor to confine water and protect the wellbore walls. Dikes and drain ditches were used to collect the oil until the flow had diminished to a point where the well could shut in or capped. Since oil is generally found at shallower depths most of the earlier wells were completed as oil wells. This was a colossal waste of reservoir energy but it was the only completion technique available (*Short 1983*).

Further development of this process led to fully cased wellbores in which the interval of interest is perforated. Generally, modern completions are now undertaken in deep, heated and painful conditions. In all cases, achieving the completion and eventual production objectives are a result of careful planning and preparation.

The cost breakdown example shown in ***Table 2*** was prepared for a 10.000ft land well. Due to the variations in specific drilling and completion conditions and options, it is difficult to present data for a 'typical well'. However, in the example shown, 'completion equipment' accounted for approximately 10% of the total cost for the well.

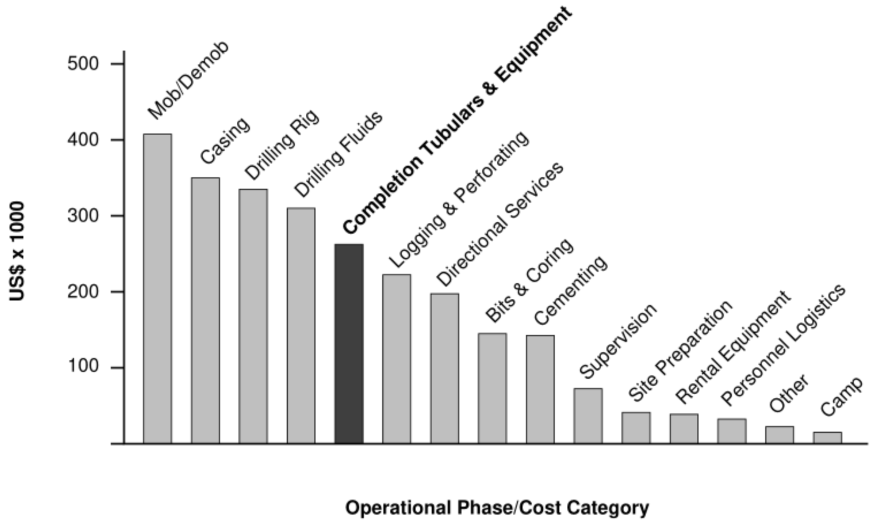

Table 2: Well cost breakdown example -10,000 ft land well (*Speight, 2011*)

1.3 The role of the Completion Engineer

Completion engineers should perform as part of a team. Although a field development team will encompass many people, some of the vital interactions are identified in ***Figure 2***. In the middle of this diagram, completion engineers have been placed, not because they are more important than anyone else but because they probably need to interact with more individuals. As completions are the interface between facilities and reservoir, both had to be understood by completion engineers. A subsurface team, a facility team and a drilling team are further subdivided into many teams. Which sub-team the completions engineers belong to, varies. Completion engineers are often part of the drilling team. Completion design is not a separate discipline in some businesses, but a role performed by drilling engineers. In another corporation, it is part of a petroleum engineering discipline sub-group that includes reservoir engineering, petrophysics and well operations. To a large extent, how the overall field development team is split up does not matter, so long as the tasks are done on time and issues are communicated between disciplines.

The timing of completion engineering involvement does matter – especially, they need to be involved early in the field development plan. Completion design can have a large effect on facility design (e.g. artificial lift necessities such as power). Completions have a large effect on the drilling design (e.g. hole and casing size and well trajectory). They additionally influence well numbers, well locations and production profiles. A field development team involved at the starting point comprises a geophysicist, geologist, drilling engineer, reservoir engineer, and facilities engineer (*Bellarby 2009*). By the time a completion engineer joins a team, it has already decided the well locations, casing sizes, and some aspects of the facilities agreed upon. Therefore, all a completion engineer needs to do is fit the completion into the casing and produce the fluid to given surface pressure. Many opportunities for improvement are lost this way. A significant role of completion engineers is to work with the service sector. The service sector can remarkably supply the drilling rig, services (wireline, filtration, etc.), equipment (tubing, completion equipment, etc.), consumables (brine, proppant, chemicals, etc.) and rental equipment. Importantly, the service sector will provide the majority of people who do the actual work. Inevitably, there will be multiple service companies involved, all hopefully fully conversant with their products. A vital role of the completion engineer is to spot and manage these interfaces in person, and to not leave it to others.

For small projects, a single completion engineer supported by service corporations and specialists is commonly sufficient. Ideally, the completion engineer designs the completion, coordinates equipment and services and then goes to the wellsite to oversee the completion installation. The engineer then writes the post-job report. If one individual design the completion and another installs it, then a good interface is needed between these engineers. A recipe for a poor outcome is a completion designer with little operational experience and a completion installer who only gets involved at the last minute.

For large projects, the completion design could also be distributed to more than one engineer. There could also be an engineer concentrating on the reservoir completion (e.g. sand control), another concentrating on the upper completion (e.g. artificial lift) and probably a number of them concentrating on installing the completion. Such an arrangement is fine so long as someone is coordinating efforts and looking at the wider issues.

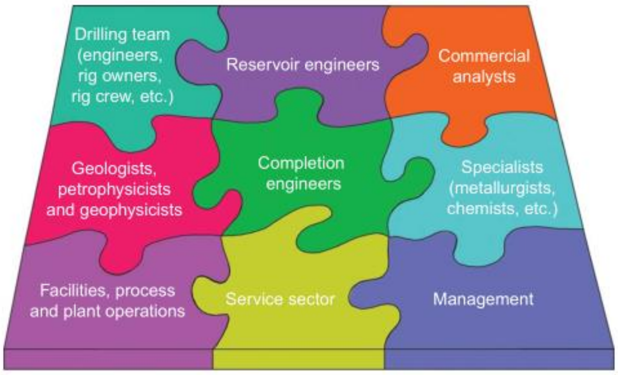

Figure 2: Team Integration (*Bellarby 2009*)

1.4 Factors Affecting Completions

The basic principle of completions is simple – perforating the casing and cement sheath to generate a smooth flow channel. Pressurized fluids flow to the surface of the reservoir through the well. Theoretically, the procedure is deceptively simple, so there may be a tendency to overlook, bypass or shortcut operations that ensure that the reservoir is produced at the maximum efficient rate (MER). The MER allows for the economic recovery of the maximum volume of hydrocarbons from the reservoir before depletion. Depletion is the point in the well's producing life where hydrocarbons cannot be produced economically by conventional, primary production methods.

The basic concept of reservoir engineering applies to completions. Failure to recognize and observe these concepts may have adverse effects (***Short 1983***). The actual completion may be relatively simple, but the rationale and assessment process used to select the method can be detailed and complicated, requiring training and experience.

Many factors affect the completion process. There is a complex of the formation and wellbore conditions, the types of completion tools and equipment, and the various completion procedures and their restrictions and applicability to the well - being completed. One of the first considerations is whether the well is a *development or wildcat well.*

- Equipment requirements, production methods and stimulation for development wells *(a well drilled in a proved production field or area to extract natural gas or crude oil)* generally are established by other completed wells in the field that are already on production. This basic rule always reviews what has been done on other wells or in similar zones, so it can be used as a guide to improving our operations. This may prevent the operator from overlooking a good zone that appears questionable on the data or may save the expense of trying to complete a zone that will be nonproductive.
- The wildcat well, which is a small exploratory oil well, often presents a more difficult problem. The operator must depend on experience since few wells that can be used for correlative information. The operator's next objective is to hire a landman to acquire drilling rights. The landman's main responsibility is to determine who is going to own the mineral rights in the area to be drilled (***Morton-Thompson & Woods 1992***). So, the landman is the operator's agent who takes care of all the negotiation parts with the landowner so that the terms and conditions would be acceptable for the operator. After getting the lease and approval of license operator hires the specialist consultants to conduct other rig side jobs such as casing, cementing, logging, perforating, fracturing, acidizing, drilling fluid preparation etc. If there are one or more potential zones the well would be completed for production. On the other hand, if there are no formation zones, the well would be plugged and abandoned following the regulations that protect the water zones drilled through.

  When a well is completed, consideration should be provided to pressure maintenance and secondary, tertiary, and enhanced recovery. In many cases if these processes are initiated early in the primary well production life of the well, the total amount of hydrocarbons recovered from the reservoir will be significantly increased.

<u>Other Basic Completion Concepts</u>

1.4.1 Porosity

The exploitation of fluids within porous media is discussed in all of the petroleum engineering. Reservoir rocks include solid material and interstitial pore spaces that may or may not be associated with. *Porosity characterizes the capability of a reservoir to store fluid due to the attendance of voids.* These spaces can be stuffed with a gas, water or two or more at the same time. The calculated porosity of producing reservoirs ranges from about 5-15% in dolomites or limestones, 10-25% in sandstones and over 30% in many of the chalk formations.

In most unconsolidated formation, porosity relies on the grain size distribution. If every grain is close to the same size, but in most cases where a wide range of grain sizes are available, the porosity ranges from 15 to 25% (*Cook 2014*). There are also, severe cases of formations with mixtures of large and tiny grains that may have porosities less than 15%. For clastic rock, porosity is closely related to permeability with obvious correlativity. The porosity of clastic rock depends mainly on sedimentation and diagenesis, including clastic grain size and degree of sorting, pressure solution, compaction, cementation, and dissolution. Generally, porosity decreases as the cement content increases. The porosity of sandstone with argillaceous cement is greater than that with carbonate mineral cement. The pore abundance of granular carbonatite, different from the organic framework of carbonatite, is similar to that of sandstone and is influenced easily by grain size, sorting, shape, and cement content. The porosity of dolomite does not correlate with these properties (*Wan 2011*).

The following generalized relationship defines this significant rock property mathematically:

$$\text{Porosity} = \phi = \frac{V_p}{V_b} \tag{1-1}$$

$$\text{Porosity} = \phi = \frac{V_b - V_{gr}}{V_b} \tag{1-2}$$

$$\text{Porosity} = \phi = \frac{V_p}{V_{gr} + V_p} \tag{1-3}$$

where porosity is usually designated by the symbol φ and is expressed as a percentage

$$\phi = (V_p/V_t) \times 100 \tag{1-4}$$

V_p = pore volume

V_b = bulk volume or V_t = Total rock sample volume = V_p + V_s

V_{gr} = grain volume

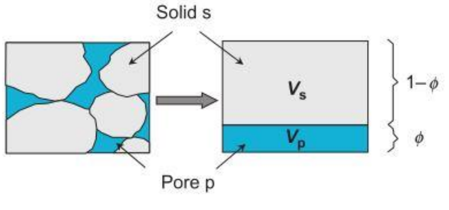

Figure 3: Porosity (*Cubitt, 2015*)

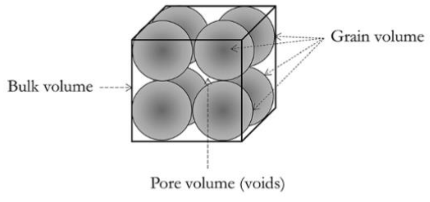

Figure 4: Bulk, grain, and pore volume (*Moshood, 2019*)

Qualitative Description	Porosity (%)
Poor	ϕ < 5 %
Fair	5 % < ϕ < 10 %
Moderate	10 % < ϕ < 20 %
Very Good	20 % < ϕ < 30 %
Excellent	30 % < ϕ

Table 3: Reservoir Porosity Values (*Stamataki, 2005*)

One of the first measurements obtained in any exploration scheme is porosity and a covetable value is necessary of any further activities to be continued towards the future utilization of a reservoir. In the absence of significant porosity, an effort to utilize a reservoir is not necessary. (***Economides et al. 1994***).

There are two basics types of methods for determining porosity: those that directly yield porosity and those that independently yield values for grain volume, pore volume, or bulk volume. In the laboratory, many analytical techniques can be used and the most commonly recommended are presented below.

- **Gas Expansion Method.** This is used in deciding the amount of grain. It is often referred as helium porosimetry and Boyle's Law method.

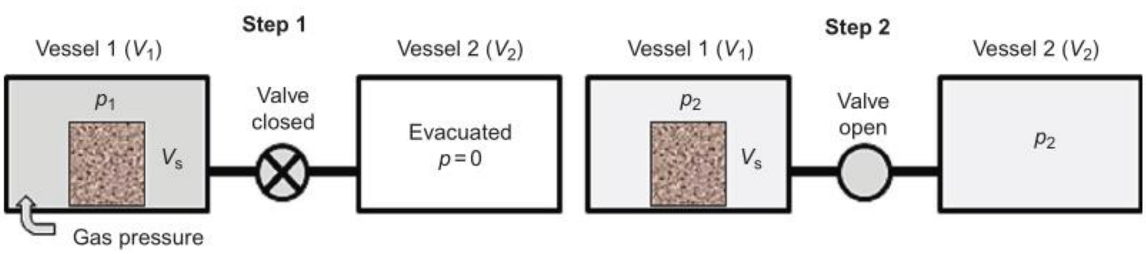

Figure 5: Gas expansion technique for determination of grain volume (*Cubitt, 2015*)

- **Mercury Archimedes Method.** This approach, used to calculate bulk volumes, is based on the fact that a nonwetting fluid will not randomly invade a sample.
    - The mass of the evacuated sample is measured.

- The sample is saturated with a liquid of a density r (e.g., water) its mass is then determined in air.
- The saturated sample's mass is measured while fully immersed in the saturating fluid.

- **Caliper Method.** By calculating the length and a diameter of a valid cylinder sample, this method is used to calculate bulk volume.
- **Summation of Fluid Method.** This method is used to assess the porosity of uncleaned samples.

Absolute and Effective Porosity

Absolute porosity is related to the ratio of total pore space to the bulk volume. Because of cementation (precipitation of binding materials between rock gains) over geological time, pore spaces may become isolated (unconnected) and, as such, they do not contribute to recoverable fluid volume (*Passey & Brackett, 2006*). The primary interest of reservoir engineering is recoverable hydrocarbon, which resides mostly in the volume of the connected pores. However, in recent times, unconnected volume, especially in unconventional reservoirs, has become increasingly important as it can be recovered by creating multiple hydraulic fractures. Defining porosity based only on the space of the interconnected pores (excluding voids that are not connected) provides effective porosity. Effective porosity is therefore defined as the ratio of the inter-connected porous volume to a material's bulk volume (*Moshood, 2019*).

1.4.2 Permeability

Permeability is an important index for a well completion mode option. Permeability is a property that measures how quickly a single fluid (gas or liquid) flows when a pressure gradient is applied through the related pore spaces (*Mackay 1994*). Hence, any reliable method for determining the permeability of a core sample would broadly involve fluid flowing at a known rate through porous material under counted differential pressure (*Moshood 2019*). The rock permeability, k, is a significant rock property because it inspects the directional movement and the flow rate of the reservoir fluids (*Hubbert 1956*).

The permeability concept used darcies as a unit of measurement but in many cases most productive formations will be between 0.001md (1md = 0.001 darcy) and 1000 millidarcies (1 darcy), (*Ahr 2008*). Permeability depends on the absolute grain size of the rock, presence of fractures, how well the sediments are sorted, type of cement, in situ stress value and how much chemical modification has occurred in the matrix. Large-grained sediments with a minimum of fine particles usually have higher permeabilities than fine-grained sediments with small pores that have lower permeabilities.

Methods used to determine permeability are:

- Direct measurements at samples: cores, core plugs.
- Direct tests: well and drillstem tests, wireline formation testers, pump tests,
- Indirect methods using grain size parameters (particularly for unconsolidated sediments),
- Indirect methods using wireline logs (NMR, Stoneley waves)

This important rock property is mathematically determined by the following generalized relationship:

$$Q = \frac{k}{\mu} A \frac{\Delta P}{\Delta L} \tag{1-5}$$

or

$$q = \frac{Q}{A} = K \frac{h_1 - h_2}{L} \tag{1-6}$$

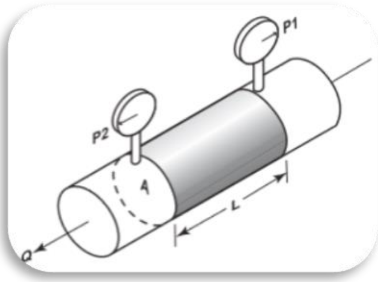

Figure 6: A modified Darcy apparatus to measure permeability (*Fjaer et al. 1992*)

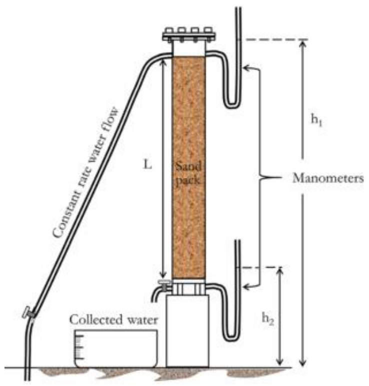

Figure 7: Henry Darcy's experimental setup for vertical flow (*Fjaer et al. 1992*)

In these expressions,

Q = constant volumetric flowrate of water, with units of (m^3/s)

k = permeability of the rock. It is known as absolute or specific permeability and has the dimensions of an area with units of (m^2).

A = cross-sectional area of the rock core with units of (m^2).

P_1, P_2 = inlet / outlet pressures, with units of (Pa)

μ = viscosity of the fluid, with units of (Pa s)

L = length of the core, with units of (m)

h_1 = height of manometer 1

h_2 = height of manometer 2

The permeability expression is written

$$Q\frac{\text{cm}^3}{\text{s}} = k(\text{darcies})\cdot\frac{A}{\mu}\frac{\text{cm}^2}{\text{centipoise}}\cdot\frac{dP}{dL}\frac{\text{atm}}{\text{cm}} \tag{1-7}$$

Or, 1 darcy of permeability is defined as when a fluid with unit viscosity flows at a rate of 1 cm^3/s from a rock sample with a cross - sectional area of 1 cm^2 under a differential pressure of 1 atm/cm.

Qualitatively, reservoir permeability values can be graded in the following manner:

Qualitative Description	Permeability (mD)
Poor	k < 1mD
Fair	1 mD < k < 10 mD
Moderate	10 mD < k < 50 mD
Good	50 mD < k < 200 mD
Very Good	200 mD < k < 500 mD
Excellent	500 mD < k

Table 4: Reservoir Permeability Values (*Stamataki, 2005*)

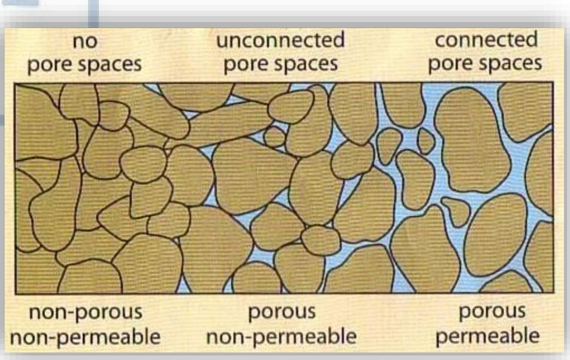

Figure 8: Relationship Porosity – Permeability with connection of the pores (www.arab-oil-naturalgas.com).

1.4.3 Relative Permeability

This permeability is mainly a function of fluid saturation and was used as a reservoir property. It depends on other factors, such as saturation history, temperature, pore pressure, overload pressure, and interfacial tension. In reality this is only an approximation, since such a use of permeability is accurate only if the fluid is also the only saturating fluid (*Economides et al. 1994*). In such case the *absolute* (when total pore volume is fully saturated with a single fluid) and *effective* (when the same fluid only occupies a fraction of the total pore volume) permeability are the same (*Moshood 2019*). So, these effective permeabilities are related to the 'relative' permeabilities, ***figure 9,*** (also rock properties) by:

$$k_e = k \times k_r \tag{1-8}$$

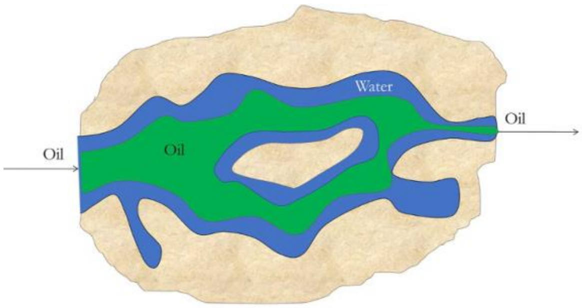

Figure 9: Flow of oil in the presence of water (*Moshood, 2019*)

Hence,

$$k_r = \frac{k_e}{k} \tag{1-9}$$

where k_e =effective permeability, k =absolute permeability, and k_r =relative permeability. Absolute permeability is a porous media/rock property that is a rock characteristic to allow the passage of fluid flow. It refers to the ability of the porous media/rock to conduct a fluid when its saturation is 100 percent of the pore space (*Owens & Archer, 1971*). Effective permeability is the porous material's ability to conduct a fluid when its saturation is less than 100 percent of the pore space.

1.4.4 Saturation

Saturation is called the fraction of pore space containing water and is usually implied by an S_w. The most widely employed parameter is the water saturation which is used by reservoir engineers to characterize the quality of the reservoir unit being investigated. This parameter may be affected by a multitude of rock properties (grain size or shape, composition, cementation and packing sorting) The remaining fraction of the pore area is called hydrocarbon saturation S_h compressed by oil or gas. The simple balance $S_h = 1 - S_w$ represents all the pore space within a rock. In the reservoir, the oil or gas always shares the pore spaces with water, ***Figure 10***. The relative amount of the oil/gas and water sharing the reservoir pores will vary from a reservoir to a reservoir, is expressed as a percent and always adds up to 100% (*King 1996*).

This important property is determined mathematically by the following generalized relationship:

$$S_o = \frac{\text{volume of oil}}{\text{pore volume}} \tag{1-10}$$

$$S_g = \frac{\text{volume of gas}}{\text{pore volume}} \tag{1-11}$$

$$S_w = \frac{\text{volume of water}}{\text{pore volume}} \tag{1-12}$$

Vo: Volume of Oil

Vg: Volume of Gas

Vw: Volume of Water

$$S_o + S_w + S_g = 1 \tag{1-13}$$

It can also be seen from Equations 1.10 and 1.13 that

$$\text{Volume of gas} + \text{Volume of Oil} + \text{Volume of water} = \text{pore volume} \tag{1-14}$$

So, if fluid saturations are accurately measured on a reservoir rock sample, the summation of volumes of individual fluid phases can also be used to determine the pore volume (or porosity if the bulk volume is also known) of that particular sample because fluid phases originated from the pore spaces of that very sample. To illustrate the significance of equation 1.8, the fluid saturation distribution for a hypothetical core plug sample is shown in ***Figure 10*** (*Dandekar 2013*).

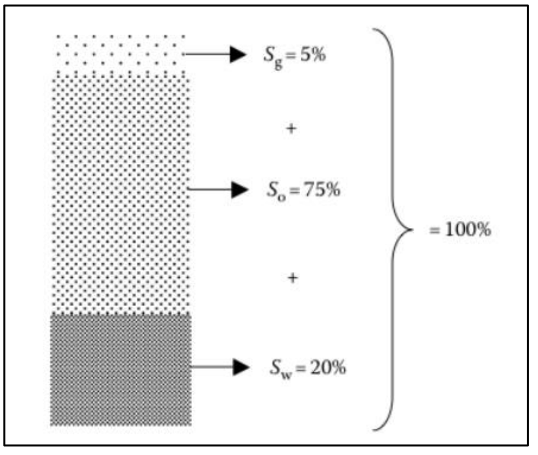

Figure 10: Fluid Saturation distribution in a hypothetical reservoir rock sample (*King 1996*)

Generally, the following types of saturation can be defined:

- **Critical oil saturation S_{oc}**: For the oil phase to flow, the oil saturation must overdraw a certain value which is termed critical oil saturation. At this specific saturation, the oil stays in the pores and will not flow.
- **Residual oil saturation S_{or}:** During the displacing procedure of the crude oil system from the porous media there will be some remaining oil left that is significantly described by a saturation value that is greater than the critical oil saturation (*Craft & Hawkins, 1991*).
- **Movable oil saturation S_{om}:** Movable oil saturation is another saturation of interest which is defined as the fraction of pore volume occupied by movable oil.
- **Critical gas saturation S_{gc}:** As the reservoir pressure drops below the boiling point pressure, gas evolves from the oil phase and therefore the saturation of the gas boosts as the reservoir pressure declines. The gas phase stays immobile until its saturation exceeds a certain level of saturation, called critical gas saturation, above which gas begins to move.

- **Irreducible water saturation, connate water saturation, and critical water saturation are generally denoted by S_{wi} (or S_{iw}):** The critical water saturation is used to determine the maximum water saturation at which the water phase will remain immobile (*Kassinis 2015*).

Well logging and core analysis methods can be used to determine reservoir fluid saturations. It is impossible, however, to substitute the well logging method, by which the fluid saturations can be obtained, for the core analysis method. During coring, the fluid (oil, gas, and water) may invade the core. (*Wan 2011*) After the core is taken to the surface, its original saturation conditions may be changed due to changes in temperature and pressure. It is generally recognized that the water saturation of the core only changes a little using the sealed coring with the oil-based drilling fluid.

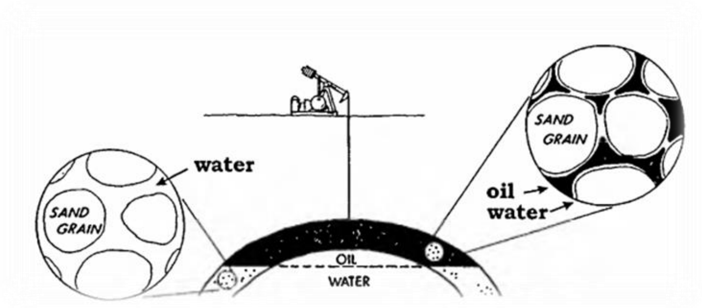

Figure 11: Magnified view of oil and water saturation in the pores of a sandstone oil reservoir (*Dandekar 2013*).

1.4.5 Natural Fractures

To a great extent, it is the nearly omnipresent presence of fractures that makes the mechanical behavior of rock masses unlike from that of most engineering materials. These fractures also cause the behavior of rock masses to differ from that of small laboratory – sized rock samples. Natural fractures have a dominant influence on the mechanical behavior of rock masses, since existing fractures provide planes of weakness on which further deformation can more readily occur. Fractures also often provide the major conductors through which fluids can flow. Where solution etching or cementation forces are active, the fractures may be widened into extensive vugs with permeabilities of hundred of darcies or filled completely with precipitated minerals (*Jaeger et al. 2007*). Natural fractures influence flush production or high production rate that reduces quickly after bringing on a new well or the start of flow in a well that has been shut-in. Although they serve as conductive pathways for oil or gas production, they also will impart water at a faster rate than the formation matrix, leading to early breakthrough of other type floods or water and sweep problems in reservoir engineering.

1.4.6 Reservoir Pressure

Reservoir pressure means that the pressure of the fluid in pores and fractures, reflects the energy of the reservoir and is that the power thrusting the fluid to maneuver in the reservoir. The right well completion design, effective utilization of reservoir energy, and rational development of field presuppose illustrating the pressures of various reservoirs and distinguishing the different pressure systems. The reservoir pressure can be determined by measurement using bottom-hole pressure gauge, well testing, or graphics (***Wan 2011***).

Generally, formation pressure is estimated by the pressure gradient and the pressure coefficient. The pressure gradient (MPa / 100 m) is the pressure variation value corresponding to the sea level elevation differentiation in the same reservoir. There may be multiple pressure systems in an oil and gas field. A reservoir must be in the same pressure system. After a reservoir is put into development, pressures in adjacent reservoirs may change due to differences in permeability, energy recharge, and engineering measures (***www.petrowiki.org***).

The general types of reservoir drive forces (to the limit of general importance in well completions) are:

- **Solution Gas (R_s)** is defined as the quantity of gas dissolved in oil at reservoir pressure and temperature. The solution gas - oil ratio is usually expressed in terms of scf of gas per stock tank barrel of oil.
- **Gas Cap expansion - drive reservoir** is a gap - cap reservoir in which the expanding gas cap is responsible for the majority of the gas expansion. A gas cap is a free-gas zone that overlies an oil zone. *Production efficiency varies from approximately 15% to 40% with an average close to 25%.*
- **Water drive:** Reservoir pressure usually remains high and responds rapidly, decreasing or increasing as the field production rates are increased or decreased, respectively. *Production efficiency is between 35% and 80% with a general average for this type of reservoir of approximately 50%.*

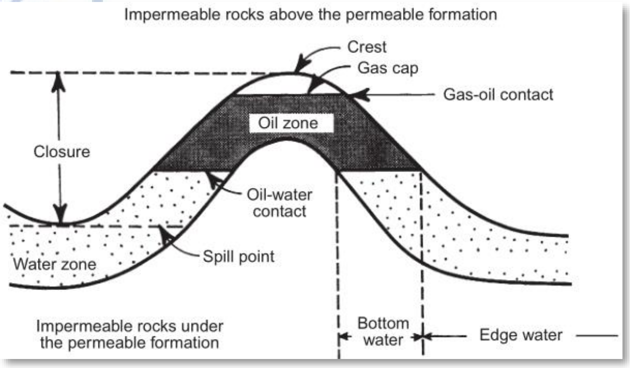

Figure 12: Idealized cross section through an anticlinal trap formed by a porous, permeable formation surrounded by impermeable rocks. Oil and gas are trapped at the top of the anticline (*Wan 2011*)

1.4.7 Well Temperature

The reservoir at static conditions includes a shut-in or reservoir temperature that is typical of the depth times the geothermal gradient for that area. A 13,000 ft deep reservoir in one part of the world could have a bottom hole temperature of 160ºF, whereas the same depth reservoir in a hotter geothermal area may be 360˚F.

As the well flows, the bottom hole temperature will abort counting on the type and amount of gas, and the pressure decline (***www.arab-oil-naturalgas.com***). The cooling is created by the expansion of gas. Temperature reductions low enough to freeze water may form ice or "hydrates" in some gas wells whereas wells with a smaller ratio of gas to liquids will flow hot to surface.

1.4.8 Fluid Properties

Rheological properties and the density of the drilling fluids are also among the very significant parameters to be registered for optimization purposes. Usually the drilling fluid density is measured through calibrated mud weight (MW) sensors (***Donnez 2007***). Rheological properties on the other hand are still measured manually. Recent developments regarding real-time pipe viscometers dictate alternative solutions. There are experimental studies executed in the laboratory using pipe-viscometers. Continuous real-time viscometer probes placed on the flow line could facilitate data acquisition over the rheological properties of drilling fluids in real-time (***Dake 1978***).

1.5 Well Architecture

A fundamental aspect of the well design is identifying the well architecture. The architecture of the well must allow drilling to the final depth and reaching all objectives, withstand the various pressures and fluids that can be encountered during the well's life, allow the performance of all operations required to evaluate the formations, enable the well to be prepared for optimum output or injection and, last but not least, allow the well to be drilled under the best economic conditions (*Kassinis 2015*).

The main points to be identified during the design of the well are the casings setting depth, diameter and wall thickness, design cases (for bursting, collapse, tension) and their mechanical characteristics (steel grade and metallurgy). The well is then designed and specifically built according to:

- The diameter of the last casing to be run in the hole (several casing diameters are used to reach the target).
- The pore and fracturing pressures of the drilling formations.
- The lithology of the formations to drill.
- The depth attainable.
- The limitations (safety, environment, local regulations etc.).
- The type of casing (casing or liner).

1.6 Deciding the fate of a Well

Once drill-stem testing and well-logging operations are finished and the results have been analyzed, the management of the company has to determine whether to complete the well as a producing well or to plug it as a dry hole. If the evidence shows that there is no oil or gas or that they are not present in sufficient quantities to recover exploration, construction and production costs and to produce investment income, the well is likely to be plugged and abandoned as a dry hole. If, on the other hand, evidence shows the existence of oil or gas in sufficient quantities to allow the recovery of these costs and to provide the business with a profit, then an attempt will be made to complete the well as a producer (*Nardone 2009*).

Well completion refers to operations that plan a well for production (or injection). These operations include the preparation of the reservoir to wellbore interface to the required specifications, perforation and stimulation as required, installation of the production tubing and associated down hole equipment (the 'completion string') and installation of the surface production wellhead. Reservoir, production and well engineers should jointly establish the design of a completion string according to the reservoir parameters, expected well performance, mechanical considerations and requirements for manufacturing operations and well intervention policy.

Wells are completed with equipment at various borehole levels that allow the measurement of liquid and gas content, as well as the remote control to allow shutting production from certain areas of the borehole (used in situations where a certain area produces, for example excessive water). Well completion operations are designed to ensure effective communication between reservoir and wellbore, optimized well performance throughout field life, well mechanical integrity, minimum well workover/intervention requirements and safety at all times. In specific reservoir cases, completion may also allow to produce selectively multiple reservoirs or layers, isolate layers producing substantial water or gas and control sand influx from non-consolidated formations.

Abandoning the Well

When the well is to be filled and abandoned as a dry hole, a cementing company is called to the drill site. The well bore is loaded with drilling fluid, which includes additives that give it special properties and prevent its movement from the well bore into the surrounding rock. Cement plugs are required within the well bore at intervals where porosity has been observed to isolate these porosity zones and prevent the transfer of formation fluids from one formation to another. The cement is pumped into the well bore through the drill string. Cement is mixed on the surface in special trucks fitted with high-volume pumps (***Boyun et al. 2017***). The pumps are attached to the drill string which is inserted into the well bore at a predetermined depth. A quantity of cement is pumped through the drill string into the well bore and displaced out of the bottom of the drill string with drilling fluid. The drill string is then extended to the next interval that is to be cemented. This process is repeated until all the required plugs have been set.

A cement plug is also set at the base of the surface casing, which remains in the hole, and another plug is set at the surface. For onshore cultivated areas the surface casing is cut off below plow depth level. The steel plate is welded at the top of the surface casing. All drilling equipment and materials are removed from the drill site. The mud pits are allowed to dry up and are backfilled and the site is preserved as close as possible to its original condition.

Completing the Well

If a decision to complete the well as a producer is made, casing is shipped to the site and a cementing company is named. The well bore is filled with drilling fluid that contains additives to avoid corrosion of the casing and to prevent the transfer of the fluid from the well bore into the surrounding rock. The casing is threaded together in almost the same way as the drill string and inserted into the well bore. The casing can be placed to a total depth of the hole or a cement plug may be set at a particular depth and the casing can be placed on the top. At the surface, cement is mixed just as if the well had to be plugged in. The cement is then poured into the casing and pushed out of the bottom with water or drilling fluid. Then the cement flows up and around the casing, filling the gap to a predetermined height between the casing and the well bore. With the casing, special tools used to allow the cement to be placed between the well bore at specific intervals and outside of the casing. This is done to protect the casing and to prevent the transfer of formation fluids from one formation to another.

1.7 Well Completion Activities

If the design well depth is reached, it is important to test and analyze the formation to determine whether the well should be completed or plugged and abandoned for production.

To complete the well production, casing is installed and cemented, and the drilling rig is dismantled and relocated to another site (*Laik 2018*). Therefore, the well completion operations include:

- Conducting Drill Stem Test
- Setting Production Casing
- Installing Production Tubing
- Installing the Christmas Tree
- Initiating Production Flow

- Installing Beam Pumping Units
- Servicing as required after the start of production

1.7.1 Conducting Drill Stem Test

To determine the potential of a formation or zone from which the oil or gas show was observed, the operator may order a Drill Stem Test (DST). The DST crew that sets up the test tool at the bottom of the drill stem uses these tests, then lowers it to the bottom of the hole. A hard rubber seal called packer is extended by the weight applied to the test tool. Opening the tool ports enables testing of the formation pressure This method helps workers to determine the potential of the well.

Drill-stem tests may also be executed when the driller observes a depletion in the time required to drill a foot of rock, known as a 'drilling break'. Since porous rock may be drilled easier than non-porous or less porous rock, a drilling break indicates the presence of porosity one of the qualities of reservoir rock. Drill-stem testing is accomplished by taking away the drill string from the bore hole. The drill bit is removed and a drill-stem test tool with a packer is hooked up. The test tool, packer, and drill string are inducted back into the bore hole to the desired depth. The packer, which is an expandable device, is set and expanded at the prearranged depth to insulate the zone to be tested (***www.kingwell-oilfield.com***). The test tool includes a valve which may be uncorked and closed to allow formation fluids to enter the test tool and drill string. If there are adequate fluid and pressure within the zone being tested, the formation fluid (oil, gas, water) may arise to the surface and flow into special test tanks used for that scope. If gas is present, it is tingled at the surface as a flare.

During DST a bulk of formation fluids along with the pressure of the flowing fluids are counted. The trap door may be opened and closed several times and fluid pressure build-up and drop are registered. The data gained from the drill stem testing (DST) concern the formation pressure, the reservoir permeability, the skin effect (nominates if the reservoir has been damaged or not) and fluid samples for analysis. By evaluating the flow rate or the amount of formation fluid recovered in the drill string and the reported formation pressures, it is possible to get a good indication of reservoir characteristics such as porosity, permeability, and the nature of the fluids or gas contained therein (***Kassinis 2015***).

Figure 13: Drill Stem Testing (*Amazon News*)

1.7.2 Setting Production Casing

Production casing is the last casing in a well. It can be established from the bottom to the top of the well. After a well has been drilled, should the drilling fluids be abstracted, the well would finally close in upon itself. Casing secures that this will not fortune while also protecting the wellstream from outside incumbents, like sand or water.

Consisting of a steel pipe that is joined together to make a continual hollow tube, the casing is run into the well. The unlike levels of the well determine what diameter of casing will be settled. Referred to as a casing program, the unlike levels include production casing, intermediate casing, surface casing and conductor casing (***https://www.rigzone.com***).

Additionally, two types of casing that can be run on a well. One type of casing consists of a massive string of steel pipe. The solid casing is run on the well if the formation is firm and will remain that way during the life of the well. Should the well contain loose sand that might infiltrate the wellstream, the casing is installed with a wire screen liner that will help to block the sand from entering the wellbore (***Adams 1985***).

Cementing the Casing

Cementing is one of the most significant procedures conducted on oil or gas fields. The primary task of cement work is to maintain the casing in place, to prevent corrosion (e.g. from saline formation water) and most importantly, to discourage the leakage of contaminants or gases into the annular space and to prevent them from migrating to upper or lower zones. Casing cementing includes the mechanical anchoring of the casing string in formations (transfers weight of the casing string to formations) and isolates reservoirs/formations situated behind the casing. It also maintains an annulus seal above reservoirs/formations and tightness of the annulus base, while preventing the formation from collapsing and swelling.

The cement is pumped down the casing of the well. The casing shoe makes it easier to insert the casing into the bore hole (*Archer et al.1999*). The float collar prevents the entry of drilling fluid into the casing. The bottom plug precedes the cement down the casing and the top plug leads the cement and precedes the displacement fluid.

After the cementing of the casing is completed, the drilling rig, equipment and materials are removed from the drill site. A smaller rig known as a ‘workover rig’ or ‘completion rig’, is usually brought in and placed over the wellbore. The smaller rig is used for the remaining completion.

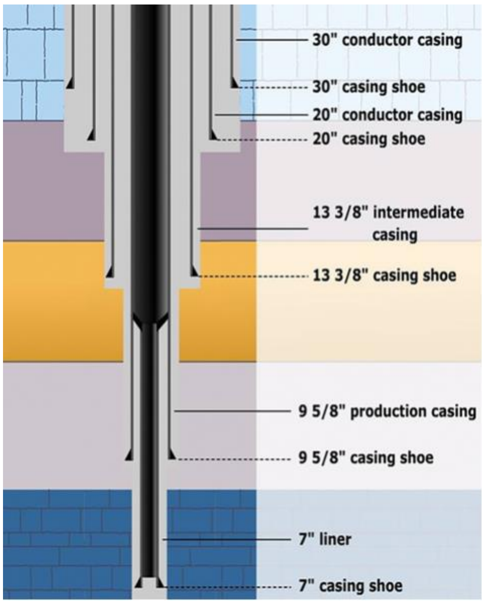

Figure 14: Typical Casing Program (https://www.slb.com)

The *large-diameter conductor pipe* prevents shallow formations from contamination by drilling fluid and helps prevent washouts containing unconsolidated topsoils and sediments. *Surface casing*, the second string, has a smaller diameter, maintains borehole integrity and avoids contamination of shallow groundwater by hydrocarbons, subterranean brines and drilling fluids. The *intermediate casing* isolates hydrocarbon-bearing, abnormally pressured, broken and lost circulation zones, providing well control as drillers drill deeper. Multiple strings of the intermediate casing may be required to reach the target producing zone. (**https://www.slb.com**). The *production casing*, or liner, is the smallest tubular element in the well. It isolates the zones above and within the production zone and withstands all the expected loads over the lifetime of the well. Finally, the *perforated interval* which is the section of wellbore that has been prepared for production by forming channels between the reservoir formation and the wellbore (***data.airwatergas.org***). In many cases, long reservoir parts will be perforated in several intervals, with short sections of the unperforated casing between each interval to allow isolation equipment, such as packers, to be set up for subsequent treatments or remedial operations.

<u>Perforating the Casing</u>

Sometimes, perforating the casing at the proper position is necessary to allow the oil and gas to enter the casing. A special perforating tool is inserted into the casing and lowered at the end of the cable to the desired location. The cable contains several electrical circuits and is connected to a recording and control truck at the surface. There are a variety of shaped charges in the perforating tool, which are spaced at specific intervals. As the the perforating contains some shaped charges high-temperature and velocity gas jets perforate the casing, the cement and the surrounding rock are fired remotely from the control truck on the floor.

1.7.3 Installing Production Tubing

A well is usually produced through tubing imported down the production casing. Oil and gas are produced more effectively through this smaller-diameter tubing than through large-diameter production casing. Tubing or reduced casing diameter is a special steel pipe that ranges from 1 1/4 to 4 1/2 in. (3 to 11 1/2 cm) in diameter and comes in lengths of about 30 ft (10m) long. Joints of tubing are connected to couplings to make up a tubing string (***Hyne 2012***). Tubing is operated into the well the same way as casing, but tubing is smaller in diameter and can be removed.

If it is anticipated that the oil or gas to be produced, will flow to the surface naturally, the tubing is equipped with an expandable packer at the lower end. This packer is made of hollow rubber that is compressed to seal the casing-tubing annulus. It keeps the tubing string central in the well and prevents the produced fluids from flowing up the outside of the tubing string. Tubing protects the casing from corrosion by the produced fluids. A completion fluid, commonly treated water or diesel oil can be used to fill the annulus between the tubing and casing string to prevent corrosion. The tubing is therefore inserted into the casing and the packer is extended or set at a predetermined point above the perforations (*Moshood 2019*). At the surface, a wellhead is mounted which is equipped with valves to regulate the flow of oil or gas from the well. The top of the wellhead is known as 'Christmas tree' because of its structure/shape.

Formation fluids flow from the reservoir to the surface through the tubing string, which is suspended in the tubing head using the tubing hanger. The tubing diameter is chosen according to the well production flowrate. The tubing material characteristics (tension, collapse, burst strength) and metallurgy are selected according to reservoir parameters such as depth, pressure, fluid corrosiveness (H_2S, CO_2 content).

The safety aspect is probably the most important feature when it comes to completing the well. Usually, there are two barriers on the external leak path (inside the tubing), the SCSSV (Surface Controlled Sub-Surface Safety Valve) and the Christmas tree valves. There are also two barriers to the internal leak path (outside the tubing), the packer, the annulus valves and the tubing hanger seal. (*Kassinis 2015*).

On offshore wells, a subsurface safety valve is used in the tubing to stop the flow during an emergency. The valve is held open by pressure. A drop-in pressure automatically closes the valve. A surface-controlled subsurface safety valve is operated with hydraulic lines that run down the well.

So finally, the steps for installing the production tubing are:

- Tubing elevators are used to lift tubing from the rack to the rig floor.
- The joint is stabbed into the string with air slips in the well.
- Power tongs for make-up tubing are used.
- This process is repeated until the installation of the tubing is completed.
- Installation of the tubing hanger at the wellhead.

The new technology allows tubing to be manufactured without joints in a continuous coil. Without the need for tongs, slips or elevators, coiled tubing is inserted into the well below the production casing and takes substantially less time to operate.

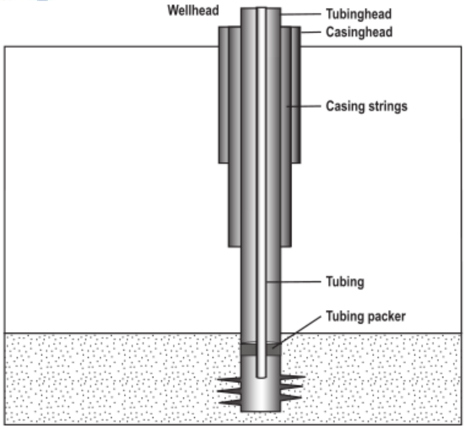

Figure 15: Completed Well (*Hyne 2012*)

1.7.4 Installing the Christmas Tree

The production stage is the most important stage of the life of a well, when oil and gas are produced. By this time, the oil rig and/or workover rig used to drill and complete the well have moved off the well bore, and the top is usually fitted with a piece of equipment called blowout preventer or "Christmas Tree" (***https://www.investopedia.com***). This vertical assembly of valves with gauges and chokes allows for adjustments in flow control of oil or gas to stimulate production.

From the outlet valve of the blowout preventer, the flow can be attached to a distribution network of pipelines and tanks to distribute the product to refineries, oil export terminals or compressor stations. As long as the pressure in the reservoir is sufficiently high, this aggregation of valves, is all that is required for production from the well. If the pressure abates and the reservoir is considered economically attainable, the artificial lift methods referred to the completions section can be employed (***Moshood 2019***).

Enhanced recovery methods such as CO_2, water, steam, and gas injection may be used to boost reservoir pressure and bring a "sweep" effect to push hydrocarbons out of the reservoir. These methods demand the use of injection wells (often chosen from old production wells) and are commonly used when facing issues with reservoir pressure prostration, high oil viscosity (***Kassinis 2015***). In certain cases, depending on the geomechanics of the reservoir– reservoir engineers may define that the ultimate recovery of oil may be increased by applying a water flooding strategy earlier rather than later in the field's development. The application of such recovery techniques is often mounted "tertiary recovery" in the industry.

The Christmas tree is also equipped with facilities required for safe access for well intervention operations using slickline, wireline, or coiled tubing.

<u>Accessories/components of the Christmas tree include:</u>

• *Tubing pressure gauge*, which is used for measuring and monitoring flowing tubing head pressure during production.

• *Swab valve or crown valve*, which is the uppermost valve on a Christmas tree, above the flowline outlet, which provides access to the wellbore from the top of the Christmas tree.

Above master valves a crossover connection is installed. Wing valves (Production wing valve and Kill wing valve), which are fixed to the lateral flanges, are used both for production and for possible workover jobs in the well (***Speight 2015***).

• The right-hand valve is often called the *Production wing valve*, which is a wing valve used for controlling and isolating production. The production wing valve provides the flow path for the reservoir to the production facilities.

• The left-hand valve is often called the *Kill wing valve*, which is fitted on the opposite side of the production wing valve and provides access for fluid injection for treatment or well-control purposes.

• *Wellhead choke*, which is a device for controlling the surface pressure and production rate from a well by changing the back pressure imposed on the well. Chokes are selected to ensure critical flow, a condition under which flow rate is a function of upstream pressure and does not depend on downstream pressure (***Hughes 1995***). Chokes may be fixed or adjustable in their opening. A variable flow choke valve is typically a very large needle valve. Its opening is graduated and adjustable in 64ths of an inch (1/64) increments called beans.

• *A fixed choke* has a fixed hole size often called a bean. A bean is a replaceable short flow tube/insert made of hardened steel with a precise diameter hole. They are graduated in 64ths of an inch with typical values of 8–20 (in 64ths) for wells with low to moderate gas rates and setting greater than 20 for liquid and high gas rate wells. A 48-choke or 48-bean choke diameter would be 48/64 in (3/4 in).

The Christmas tree is composed of two main gate valves (Upper master valve and Lower master valve) called the master valves, because they lie in the flow path, which enables the well to be closed.

• *Upper master valve*, which lies in the flow path of the fluid from the reservoir. It is often actuated hydraulically and used routinely to control the flow of fluid from the wellbore.

• *Lower master valve*, which also lies in the flow path of fluid from the reservoir and serves as a backup for the master valve and is normally operated manually.

A 20000 psia Christmas tree with dual flowlines (for increased flow capacity), is shown in ***Figure 16***. Two manual master valves are contained in the tree. Every side has both manual and hydraulic wing valves. For each valve, many land wells use separate spools. This allows the removal of valves but increases the size (and weight) of the tree. For platform wells, where space is more important, a single block setup is common. Also, it is common to reduce pressure drops and erosion potential through the side arm by using a 45^{o} angle instead of the 90^{o} angle shown in ***Figure 17*** (*Bellarby 2009*). Christmas trees need orientation concerning the intended flowlines. The tubing hanger on a single-bore hanger does not normally need orientation. For land and platform horizontal trees, the tree and tubing hanger need orientation.

For dual-bore trees, the master and swab valves are offset vertically with associated divergent wing valves.

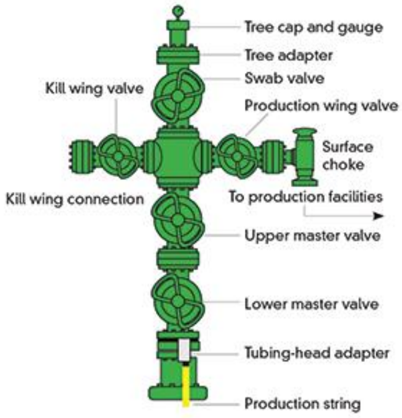

Figure 16: The Christmas tree: A collection of control valves at the wellhead (*Speight 2014*)

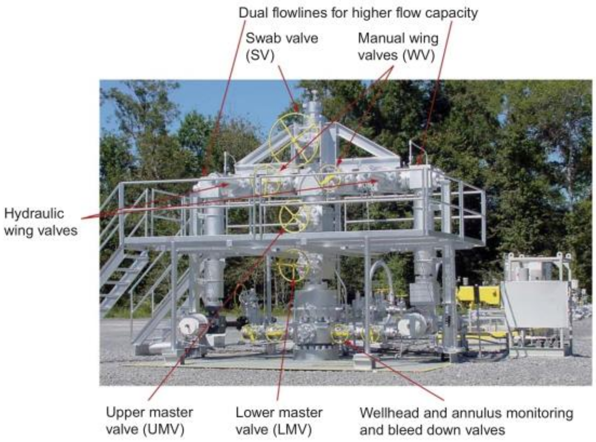

Figure 17: High pressure land tree – photograph courtesy of Gregor Kutas. (*Bellarby 2009*)

Christmas trees, mounted on wellheads, in offshore developments can be on the surface production deck (dry tree system/completion) where they are readily accessible for operations and maintenance. Although the surface dry tree system/completion increases the load on the production deck, it provides easy access to the well for intervention. (***Hossain & Al.Mayed 2015***) In deep water development, where platform installation is expensive and production is through floating facilities, a subsea tree can be mounted on a subsea wellhead on the seabed (wet tree system/completion).

In wet tree completion, more than one subsea tree can be connected to a subsea manifold through jumpers. Comingled fluid at the manifold can then be sent to a subsea boosting pump station to provide energy for the produced fluid to flow through the pipeline end termination (PLET), flow lines, and, finally, through risers to the production deck of a floating facility.

1.7.5 Starting Production Flow

Production flow is commenced by washing in the well and shaping the packer. Washing refers to pumping water or brine (salt solution) into the well to flush out the drilling fluid. Usually this is enough to get the well flowing. If not, the well may need to be unloaded. This means swabbing the well to remove some of the brine. If this does not work, flow may alternatively be started by pumping high pressure gas into the well before installing the packer. If the well does not flow on its own, well stimulation or artificial lift may need to be applied. (*Lake 2007*)

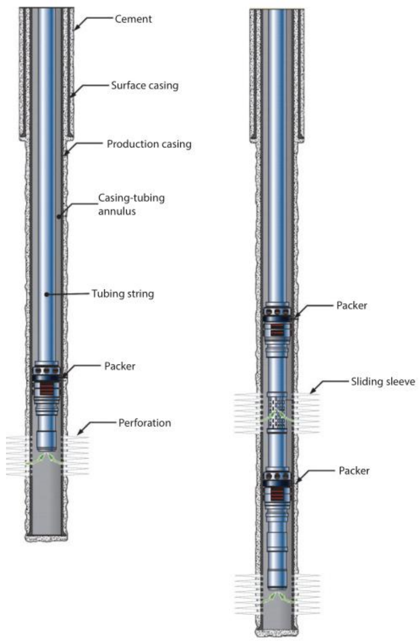

Figure 18: Different equipment for a typical well (*Hossain & Al.Mayed 2015*)

Tubing and packer are the two main components of production equipment ***Figure 18***. Tubing is needed for the processing of gas containing more than 5% hydrogen sulphide (H_2S) and for all injections and disposals except for the injection of freshwater. A production packer must be used for all injections and disposals except for the injection of freshwater, and wells containing gas with more than 5 per cent H_2S, or if a numbered highway or populated area is located within the emergency planning zone for the well (*Malcolm 1978*). Production tubing is the main conduit for transporting hydrocarbons from the reservoir to the surface. It runs from the tubing hanger at the top of the wellhead down.

1.7.6 Servicing

Servicing operations assume that the well has been completed and initial production has begun. All servicing activity requires specialized equipment. The equipment is transported and rigged up to the well.

Servicing is carried out by specialized crews and consists of:

- Transporting Rig and Rigging Up
- General Servicing
- Special Services
- Workover

Figure 19: Servicing Rig (https://www.osha.gov)

Transporting Rig and Rigging Up

The first phase in well servicing operations is to transport and rig up the equipment. Servicing tasks begin after these steps.

Figure 20: Transporting Rig (*https://www.osha.gov*)

General Servicing

Wells also need on-surface or down-hole equipment to be maintained or serviced. A major component of today's oil industry is operating on an existing well to reinstate or increase oil and gas production. Service or workover may be appropriate for a well that is not performing to its full potential.

Special Services

Special services are operations that use specialized equipment and staff that conduct support well drilling and maintenance functions. For onsite safety communication between all staff is important. Therefore, all special services operations should conduct a pre-job safety meeting that involves all staff on the job site.

Workover

Workover operations include one or more of a diversity of remedial operations to try to improve productivity on a producing well.

1.8 Requirements for Well Completion

The main objective of well completion is to produce maximum recovery most safely and economically. It is the resulting outcomes of the combined effects of overall reservoir condition, rock formation characteristics and fluid properties, facilities development, drilling and workover activities, consideration of environmental impact, and finally the production. If one of the parameters is affected or influenced, the completion activities will be affected. At present, there are multiple types of well completion modes and their applicable conditions, limitations, and requirements.

- The optimum condition of communication between reservoir and wellbore should be retained to reduce formation damage to the full extent.
- The flow area between the reservoir and wellbore should be provided as fully as possible to decrease the resistance to oil and gas flow into the well as far as possible.
- The oil and gas reservoirs and aquifer should be effectively isolated to avoid gas and water channeling and interlayer interference.
- Sand production should be effectively controlled in order to prevent the borehole wall from sloughing and ensure the long-term production of the oil well.
- The oil well, which is run in after the well is completed, should not only meet the requirements of flowing production, but suit the need for artificial lift production in the later stage.
- The conditions of downhole operations and measures, including separate-zone water injection and gas injection, separate-zone fracturing and acidizing, and water shutoff and profile control, should be provided.
- The requirements of steam injection should be met during the thermal recovery of heavy oil.
- The conditions of side-tracking should be provided in the later stage of oil field development.
- The conditions of drilling horizontal branch holes of a horizontal well should be provided.
- The corrosion caused by H_2S, CO_2, and saltwater with a high salinity should be effectively prevented.
- The creeping of salt rock bed and salt paste bed should be resisted.

- Simple, convenient operation with a high level of safety, and good economic viability should be considered (*Wan 2011*).

1.9 Types of Well Completion

The type of completion depends on the structural and geological characteristics of the formation rock type, the reservoir, and the hydrocarbon existence. Generally, there are several types of well completions normally practiced in the industry. There are known as i) Open-hole Completion, ii) Perforated Completion, iii) Uncemented liner completion, iv) Cased and Cemented Completion, v) Liner Perforation Completion, vi) Multi - Zone Completions.

In some cases, various completion jobs are done to prevent problems that may arise during the productive phase of the reservoir. As an example, solids, dragged up through the production plant, causing erosion to the plant in general, or specific parts of it, such as valves or bends, may clog the completion up. It is therefore necessary to separate the solid particles from the fluids, by installing filters and sand-catching devices. The solid particles should then be properly disposed to ensure the continuous flow of production. (***Hossain & Al.Mayed 2015***).

1.9.1 Open – hole Completion

The simplest and inexpensive approach to bottom hole completion is to leave the entire drilled reservoir section open after drilling. Open-hole completion involves keeping the zone of interest, within the producing formation interval, without casing or liners (set and cemented in the reservoir cap rock) without some other protective filter, leaving the end of the piping accessible throughout the reservoir formation pay zone (*Havard 2013*).

Such completions are known as “barefoot” completions. This kind of completion is ideal where the reservoir rock is of the appropriate mechanical strength and is only feasible in reservoirs with the sufficient formation strength to prevent caving or sloughing.

Nowadays, the usage of open-hole completions is restricted chiefly to some types of horizontal wells and to wells where formation damage from drilling fluids is severe. To block an unstable formation from collapsing and plugging the wellbore, slotted screen or perforated liners may be instated across the open-hole sections.

The above characteristics of open hole completions explain why they are used in:

- Low-cost developments.
- Deep, consolidated reservoirs being produced by depletion drive secures good contact between fracture and well.
- Naturally fractured reservoirs.
- Some horizontal and multilateral wells with high prostration costs (***Batruna 2010***).

<u>There are two types of procedures for open hole completion.</u>

- After drilling to the top of the oil reservoir, the intermediate casing is run in and the well is cemented. After the cement slurry is returned to the predetermined design height, a bit with a smaller diameter is run in through the intermediate casing, and the cement plug is drilled through. Then the oil reservoir is drilled into the design depth and *the well is completed* (*Lyons & Plisga 2005*) (***Figure 21***)

- Open hole completion is also suitable for some thick oil reservoirs. If a gas cap on the top or a water-bearing bed near the top boundary exists, the intermediate casing may be run across the oil–gas interface and the upper part of the oil reservoir is sealed and then open hole completion follows. If necessary, the oil-bearing interval is perforated. This type of well completion is known as *composite well completion* (***Figure 22***).

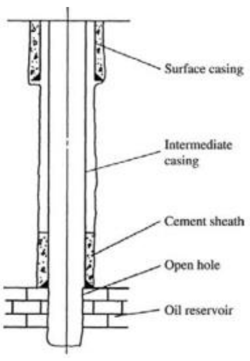

Figure 21: Initial Open Hole Completion (*Wan 2011*)

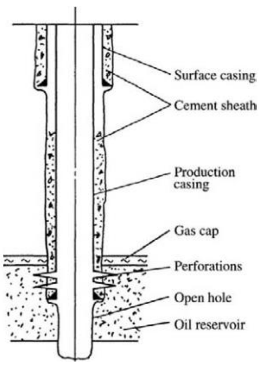

Figure 22: Composite Well Completion (*Wan 2011*)

The bit is not changed. The oil reservoir is drilled directly through to the design depth, the intermediate casing is run to the top of the oil reservoir, and the well is cemented. During cementing, the oil reservoir is padded with sand to prevent the oil reservoir below the casing shoe from damaging by cement slurry, the drilling fluid with low fluid loss and high viscosity is displaced to prevent the cement slurry from settling, or an external casing packer and cement stinger are set at the lower part of the casing to retain the cement slurry in the annulus and prevent the cement slurry from settling. (*Wan 2011*)

During well completion using this procedure, the target can be drilled through using a set of drilling tools. However, after the target is drilled through, the intermediate casing should be further run in and the well should be cemented, the cement plug should be drilled, and then the well should be re-drifted. Under normal conditions, this procedure is not applied due to the complicated operating sequence, long duration, serious formation damage, and possible formation collapse (***Figure 23***)

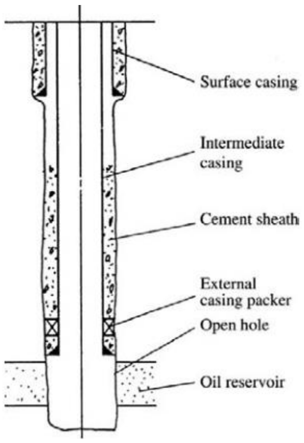

Figure 23: Final Open hole Completion (*Wan 2011*)

Open-hole completions are predominant in thick carbonate or hard sandstone reservoirs. This completion technique is produced from fracture systems or thin permeable streaks, which are difficult to identify on logs (***Byrom 2015***). Drilling and cementing operations can easily damage these formation scenarios. So, the fracture intersections and inflow potential could be maximized, due to the large surface area of drilling and completion damages, which also must be avoided.

The decision of an open-hole process relies on four key issues i) a risk of causing damage to well productivity with a cased and perforated completion ii) zonal selectivity required iii) fracture stimulation required and iv) potential sand production. Open-hole completions offer no scope for insulating individual zones for production, stimulation or remedial work. However, this bottomhole completion type is used extensively in onshore fields where cost savings from not running and perforating casing significantly reduce total well costs (***Hossain***

& Al.Mayed 2015). The advantages and disadvantages of open-hole completion types are illustrated in ***Table 5***.

Advantages	Disadvantages
Minimum rig time and formation damage	Difficult control of excess gas or water production
With gravel pack, provides excellent sand control	Difficult selective production or stimulation
No perforating, no production casing, and no cementing expenses	Frequent cleanout
No critical log interpretation is required	Liable for sand production
Full diameter hole in the pay zone improves productivity	Ability to isolate the lower part of the hole is limited
Easily deepened	
Easily converted to liner or perforated completions	

Table 5: Advantages and Disadvantages of open-hole completions (*Hossain & Al.Mayed 2015*)

1.9.2 Perforated Completion

After an oil or gas well is finished, the wellbore is isolated from the surrounding formation by casing and cement. Establishing fluid contact between the wellbore and formation, for either production or injection, demands some perforating operation (***Karakas & Tariq 1988***). Perforating is the method of making holes in the casing that go through the scabbard of cement and extend into the formation some depth. Depending on the perforation, the formation penetration will range from mainly zero to several inches, depending on the perforator used and the physical and mechanical properties of the materials being penetrated (***Hyne 2012***). The holes may be dispelled in an angular pattern around the inner of the wellbore and this dispersion is called phasing.

The variety of shots per linear foot can vary generally starting from 1 to 24 (or more if a zone is perforated many times) and this number is referred to as shot density.

This type of completions is the most common worldwide due to the selectivity, suppleness, lower costs, increased safety and convenience that they supply. Here, production casing is cemented through the producing zone and therefore the pay section is by selection perforated (***Hossain & Al.Mayed 2015***). The benefits and drawbacks of perforated well completion are contoured in ***Table 6.***

Advantages	Disadvantages
Easy control of excessive gas or water production	Perforating cost could be significant
Can be selective to stimulation	Liable to formation damage
Logs and formation samples available to assist in decision to set CSG or abandon	Selective stimulation
Easily deepened	Log interpretation critical
Adaptable to sand control	
Adaptable to multiple completion	
Minimum rig time	

Table 6: Advantages and Disadvantages of Perforated completions (*Hossain & Al.Mayed 2015*).

The Open Perforation model (***figure 24***) can be used to predict well performance.

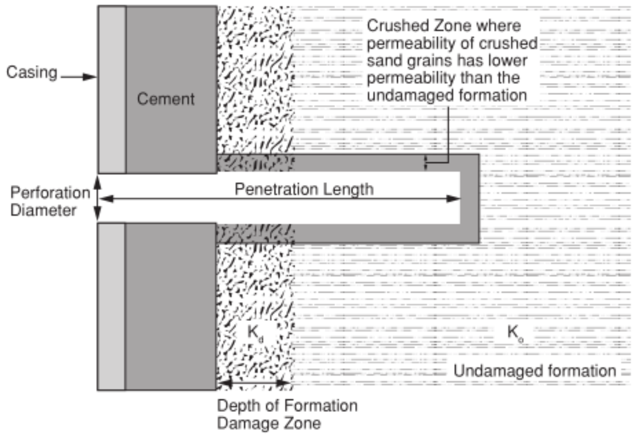

Figure 24: Flow through completions – perforated completion model (*Courtesy:Heriot Watt*).

The inflow performance is affected by the:

- **Perforation length** (L) - longer perforations are more productive.
- **Perforation diameter** (D perf) - wider perforations can show a reduced frictional pressure loss.
- **Perforation density** (n) - reducing the space between perforations will increase the well productivity.
- **Perforation phasing** - reducing the angle between adjacent perforations will increase the well productivity.

- **Depth and Permeability reduction caused by Formation Damage** - formation damage has a restricted impact on well productivity provided it is penetrated by a substantial length of the perforation.
- **Permeability and depth of crushed zone around the perforation** - perforation clean up procedures ought to be designed to get rid of this impaired crushed zone before production.
- **Formation vertical and horizontal permeability** - reduced vertical permeability impedes well production when the perforations are far apart (low shot densities).
- **Drawdown and properties of the produced fluids** - high gas and very high oil flow rates through the perforation result in further pressure losses from non-Darcy flow effects.

In the industry, there are some types of perforated completions normally practiced which are discussed below.

- **Standard Perforated Casing Completions**: These are used when the rock is reasonably stable and permeable (***Figure 25a***). This class of perforated completion consists of production casing run through the formation. The perimeters of this casing are perforated with tiny holes along the sides facing the formation, that permits hydrocarbons to flow into the well hole whereas still providing an appropriate quantity of help and protection for the well hole. 'Bullet Perforators' have been used in the past. These were basically small guns that were lowered into the well that sent small bullets off to penetrate the casing and cement (*Havard 2013*).'Jet Punching' is preferred these days. This consists of small charges fired electrically that are lowered into the well. The shot density depends on the vertical permeability, layer frequency, deliverability requirements, and method of perforation. The deep penetrating charges are desired to perforate through the damaged zone, which is caused by the drilling or completion method.

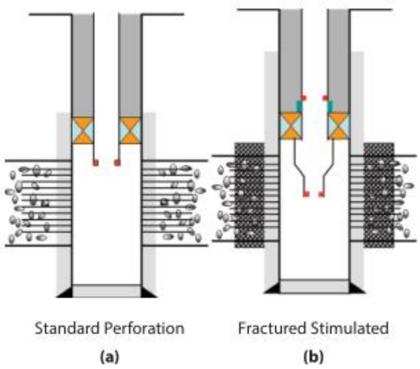

Figure 25: Different Perforated Well completions (*Hossain & Al.Mayed 2015*).

- **Fracture Stimulation:** As shown in ***Figure 25b***, fracture stimulation is used to extend the effective sand face area. It is also used to provide a high permeability flow path to the wellbore for increasing the IPR from low permeability rocks (< 25 mD).

- **Perforated Cased-hole with Liner:** The advantages and disadvantages of perforated cased-hole with liner are listed in ***Table 7***.

Advantages	Disadvantages
Minimum formation damage	Reduced well bore diameter
Excessive water/gas can be controlled	Log interpretation is critical
Selective stimulation possible	Selective stimulation
Can easily be deepened	Difficult liner cementing
Helps control sand production	More expensive (perforating, cementing and Rig time)

Table 7: Advantages and Disadvantages of Perforated completions (*Hossain & Al.Mayed 2015*).

- **Tubingless or Reduced Diameter Completions:** This kind of completion method is used in wells wherever the formation pressure is low and high flow rates are needed. In this case production must take place directly through the final lining of the well, with no support from production strings or isolation systems. Here, production tubing is cemented and perforated for production.

- **Packerless Completion:** It is connected with a tubing string and without isolation between casing and tubing. As a result, it is a more financially advantageous system. Here, only the production tubing is placed in the well. It is possible to produce both the tubing and the annulus (***Figure 26***). The production tubing can be used for injecting the kill mud. This method is somewhat restricted in terms of flow conditions and the protection of the tubing materials. Moreover, it is difficult to discover leaks in the tubing or the casing. It is also a challenge to gather bottom-hole pressure data.

- **Single String with Hydraulic Isolation Completion:** It is convenient to use hydraulic isolation and just one string in the single string completion. This kind of completion is convenient when the production layer appears to be homogeneous and a selective-zone production isn't necessary. A single tubing string consists of an isolation device and the packer (***Figure 27***). It is lowered into the well together with the isolation device and packer. A single selective completion is used where there are several production layers for one fluid. This system has only one tubing string and several packers that isolate the various production levels. By using wire-line operations it is possible to open and close the valves to allow production on single layers (***Figure 28***).

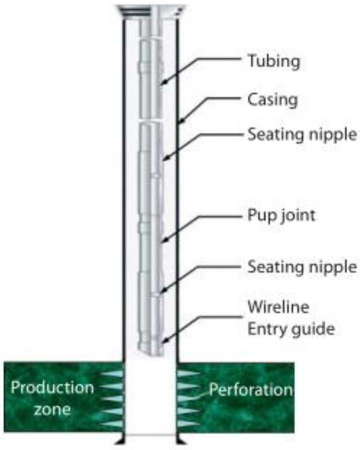

Figure 26: Packerless completions

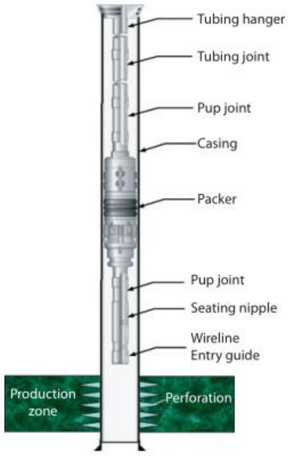

Figure 27: Single String Packer completions

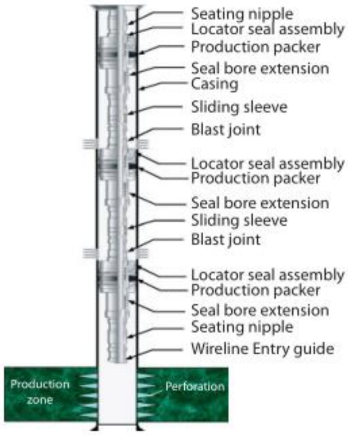

Figure 28: Selective Single String Completion

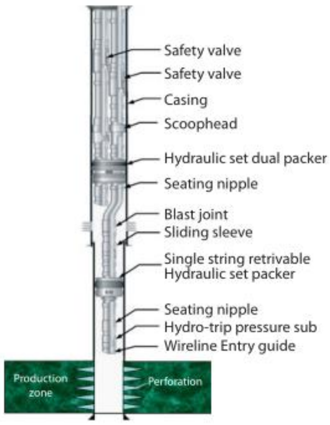

Figure 29: Dual String Completion (Hossain & Al.Mayed 2015).

- **Multiple String Completion**: Generally, the multiple tubing string completion uses two or three tubing. It is isolated by packers and allows production on different levels at the same time. Th is technique is useful when the reservoir presents different layers production zones such as oil and gas, or different types of oil. It allows us to produce selectively, while keeping production active on various levels at the same time. For the single tubing strings, it is always possible to adopt a solution similar to the single selective completion. Thus, it allows obtaining a multiple selective completion. The downside of this system is the limited diameter of the tubing, which in turn reduces the flow capacity of every tubing string.

- **Liner-tieback Perforated:** Liner-tieback completion is often applied to deep and ultra-deep oil and gas wells (high-super high-pressure wells). ***Figure 30*** shows this sort of completion. On the opposite hand, cased and liner perforated completion is only suitable for oil and gas wells with medium or low pressure.

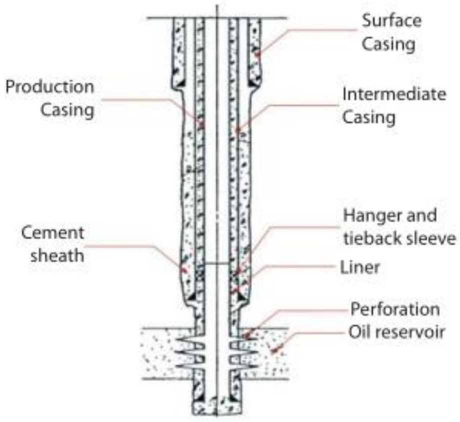

Figure 30: Liner – tieback Perforated completion (*Wan 2011*)

Explosive selection

There are a variety of different types of explosives. They vary in explosive power and temperature stability. The main explosive used is in the shaped charge. This is a secondary 'high explosive'. The explosive detonates at supersonic speed. Secondary explosives are found in the detonating cord and detonator. Secondary explosives are difficult to initiate and commonly need a primary explosive in the detonator to start detonating. Conversely, primary explosives might initiate by a small amount of heating (e.g. electrical resistance wire), friction, impact or static discharge. As such, they need to be gingerly handled and are avoided wherever possible.

Most explosives are given three-letter acronyms (TLAs) as shown in ***Table 8***. The source of these acronyms is often obscure, frequently debated and not always related to the chemical (***Bellarby 2009***) Notice the similarity of the chemical compounds in all the commonly used explosives. TNT is included in the table for comparison – its low melting point whilst making it very useful for creating molded explosives limits its downhole application.

Abbreviation	Name	Formula	Comments
TNT	*Trinitrotoluene*	$C_6H_2(NO_2)_3CH_3$	*Melts at 80°C (176°F) – therefore not suitable for downhole use*
RDX	Research department composition X	$C_3H_6N_6O_6$	Most common downhole explosive
HMX	High molecular weight RDX	$C_4H_8N_8O_8$	Higher temperature version of RDX
HNS	Hexanitrostilbene	$C_{14}H_6N_6O_{12}$	Higher temperature stability, but reduced performance compared to HMX
PYX	Picrylaminodinitro-pyridine	$C_{17}H_7N_{11}O_{16}$	Slightly reduced penetration compared to HNS, but very high temperature stability
TATB	*Triaminotrinitrobenzene*	$C_6H_6N_6O_6$	*Not used on its own downhole. Common in missile systems! Very hard to detonate*
HTX	High-temperature explosive	Combines HNS and TATB	Various different formulations possible; better penetration than HNS, with high temperature stability

Table 8: Explosives, acronyms and application (*Bellarby 2009*).

The temperature stability of the most explosives used is shown in ***Figure 31*** (***Economides et al., 1998a***). The stability of HTX is typically below, but close to that of HNS. As it is not a pure compound, the performance can vary with the formulation. Explosive power can also vary with the pressed density and grain size (***Baird et al., 1998***).

These curves are determined experimentally, with no reduction in explosive performance observed if the time–temperature limitations are obeyed. Straying beyond these limits risks the explosives degrading. This will reduce the explosive power, but also generates heat through the exothermic reaction. Possible outcomes include outgassing, low-order detonation (akin to burning) and even autodetonation. High-temperature explosives such as HNS, PYX and HTX are less likely to auto detonate, but can burn at high temperatures (***Baird et al., 1998***).

Since the explosive power usually deteriorates with the explosives that are more stable at high temperatures, a balance is needed to select the suitable explosive. This equilibrium depends on the technique of weapon deployment (***Bellarby 2009***). Guns deployed in a single trip by electricline can be downholed for considerably less time than guns deployed at the base of a permanent completion. Allowance for contingent operations, such as bad weather, which could slow down operations, should be given.

Procurement and storage of explosives is a process that takes time. In most countries, necessarily stringent legislation allows for strict controls on procurement, transport and handling of explosives. Early communication with the perforating company is required with time-critical completions, even if precise details about the well are not yet known.

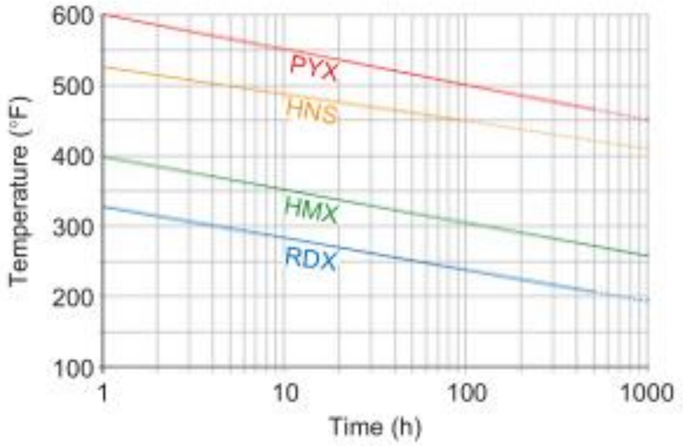

Figure 31: Temperature stability of perforating explosives (*M.J. Economides 1994*).

1.9.3 Gravel Pack Completion

Many reservoirs of relatively young sediments are so poorly consolidated that, unless the rate is significantly limited, sand will be produced along with the reservoir fluids. Sand production leads to a wide range of production problems, including the erosion of downhole tubulars, the erosion of valves, fittings and surface lines, the sand filling of wells, the collapse of casings due to lack of support for formation, and the clogging of surface processing equipment. Even if sand production can be tolerated, the disposal of the sand produced is a problem, particularly in offshore fields. A means of eliminating sand production without significantly limiting the rate of production is therefore desirable.

Sand production is controlled by the use of gravel pack completions, slotted liner completions or sand consolidation treatments, with the completion of gravel pack being by far the most common approach. *Suman et al. (1983)* review the sand-control completion practices.

Generally, gravel pack completion should be accepted toward unconsolidated formations with serious sand production. First, a wire-wrapped screen is run to the position of the oil reservoir and then gravel preferred at the surface in advance is pumped to the annulus between the wire wrapped screen and the borehole or between the wire-wrapped screen and the casing using packing fluid. So, it is forming a gravel pack bed to retain reservoir sand to prevent sand from entering into the wellbore and protect the borehole wall.

The gravel pack sand (called gravel, although it is grain-sized sand), should maintain most of the formation sand, but let very fine particles pass through it and be produced. The two most prevalent types of gravel pack completions are an inside-casing gravel pack and an openhole or underreamed-casing gravel pack (*Armentor et al. 2007*).

The under-earned-casing gravel pack offers better gravel conductivity but is restricted to single-zone completions. The formation sand must be maintained by a gravel pack completion and give the least resistance possible to flow through the gravel itself.

- **Open Hole Gravel Pack Completion.** If the geological conditions permit open hole and sand control is needed, the open hole gravel pack completion should be applied. Originally used in deviated or vertical wells, open hole gravel packs have become a common form of sand control since the mid-1990s particularly in horizontal wells, where they can be highly productive. The aim is simple*;* fill the annular space with gravel to prevent the development of formation sand and size the screen to prevent the gravel from escaping *(Bellarby 2009)*. When successfully mounted, they prevent the formation from collapsing and thus reduce the output of fines, but the filter cake (if still present) must flow back through the gravel and screen.

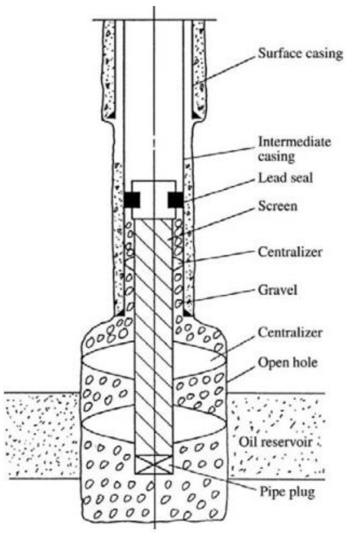

Figure 32: Open hole gravel pack completion (*Wan 2011*).

This procedure involves drilling up to 3 m above the top boundary of the oil reservoir, running intermediate casing, cementing, drilling through the cement plug with a smaller bit, *drilling-in the oil reservoir to design depth and changing into the underreaming expansion bit. It is also important to enlarge the borehole diameter up to 1.5–3.0 times the outside diameter of the intermediate casing to ensure a larger annulus, an increased thickness of the sand control bed, and an enhanced effectiveness of sand control, and then packing gravel. (**Wan 2011**).*

- **Cased Hole Gravel Pack:** Cased hole gravel pack completions are used to control sand production in perforated completions in ***Figure 33.*** Unlike the open-hole gravel pack, the cased hole gravel is placed between the cased hole and therefore the sand screen. Ideally this screen is used with the gravel forced into the perforations to hold the formation sand in place. Since the gravel has a finite permeability, an outside flow area should be achieved by using 'big hole' charges with the maximum shot density, which is dependent on gun size.

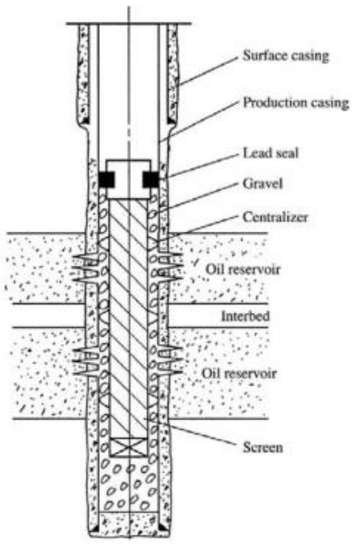

Figure 33: Cased hole gravel pack completion (*Wan 2011*).

- **Internal gravel-pack:** Internal gravel-packing is the most difficult well operation done on a routine basis. Well is cased-off and perforated (4-8 shots/ft). The annulus between screen and casing must be filled with gravel to stop sand production key to high productivity is to fill perforations with gravel. Perforation clean-up is essential (back-surging, washing). A good packing of perforations is essential, and pre-packing is common (squeeze in gravel). Water (brine) is recommended as the carrier fluid. The perforations are shot and cleaned up, and a screen is placed across the interval to be gravel

- packed. A work string is run down the well, inside the tubing, consisting of a setting tool (packer), a crossover assembly and a wash pipe.

The crossover port/packer assembly allows fluids to be diverted from the tubing into the annulus behind the screen or behind the casing. Initially, with the crossover directing fluids back up the annulus between the tubing and the casing, the tubing can be cleaned with a light acid wash, removing rust, scale, or other foreign matter and preventing them from plugging the formation and screen. For circulating the gravel, the configuration of the crossover assembly is altered to allow the gravel and carrier fluid to flow down the tubing, into the annulus behind the screen and into the perforations. The carrier fluid will pass through the screen and up the wash pipe, through the crossover assembly and up the annulus to the surface. The gravel is left behind the screen and in the perforations. Additional pressure may be applied to squeeze the gravel into the perforations, once the annulus is full of gravel. Once the gravel has been placed, the crossover assembly is adjusted to allow reverse circulation to take place, in which the excess gravel is flushed out of the wash pipe and the tubing. The crossover/wash pipe/packer assembly is then pulled out of the tubing, allowing production to take place.

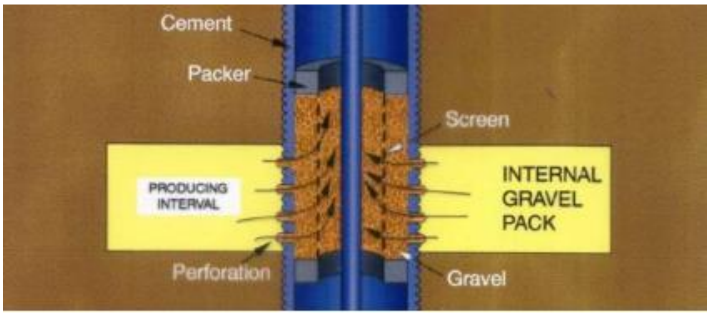

Figure 34: Internal Gravel Pack (*Renpu, 2008*).

- **External gravel-packing.** The well is under-reamed or under-milled (about 11" diameter outside 7" casing). This gravel-pack is installed at the bottom of a casing, but the casing can continue below the gravel-pack. Borehole stability may be a problem in unconsolidated formations. Essentially same equipment is used as for cased holes. It has the following advantages:

  • low drawdown and high productivity
  • long life

• no casing or perforating expense

The disadvantages are:

• difficult to exclude unwanted fluids (water)

• not easy in unconsolidated formations

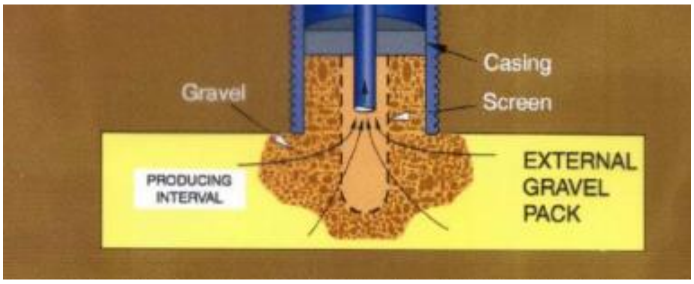

Figure 35: External gravel pack in an under-reamed cased hole (*Renpu, 2008*).

- **Chemical Consolidation.** Injection of a chemical (usually epoxy resin) which will retain permeability but bind the sand grains together. It is not widely used, because the cost of chemicals is high and only small intervals can be treated. Long intervals require successive injections. In 2006 Chevron used this technique in the Gulf of Mexico, using a furan resin system (***Armentor et al 2007, Wise et al 2007***)

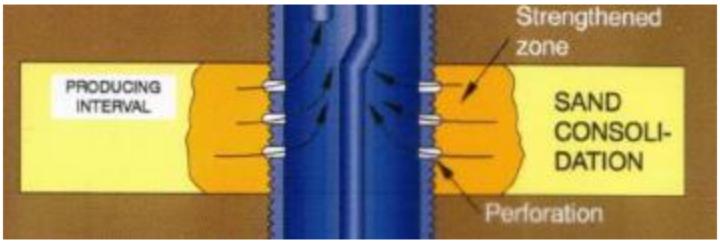

Figure 36: Chemical consolidation (*Renpu, 2008*).

1.9.4 Multiple Completions

Multiple zone completions are used for reservoirs where more than one distinct reservoir layer is crossed by a single well and there is the purpose, or legal requirement, to produce from or inject into these layers singly. Each reservoir has, by definition, its pressure regime and, if present, their own Gas-Oil-Contact and Water-Oil-Contact.

The concept of a homogeneous reservoir rarely exists in reality. However, producing formations can often be considered stratified, and their producibility depends upon the extent to which vertical flow occurs. Stratified reservoirs are created by changes in depositional conditions resulting in layers having a variable degree of the vertical permeability. Each of the producing layers has to be treated as a separate reservoir if a very low vertical permeability exists between the separate layers (*Taylor & Russel 1998*)

The main problems with multiple completions are the complexity of the downhole equipment, the difficulty of stimulation, the possible formation damage while installing the completion equipment and the difficulty of installing the equipment and conducting artificial lift operations. All of these must be considered when designing equipment and conducting multiple completion operations.

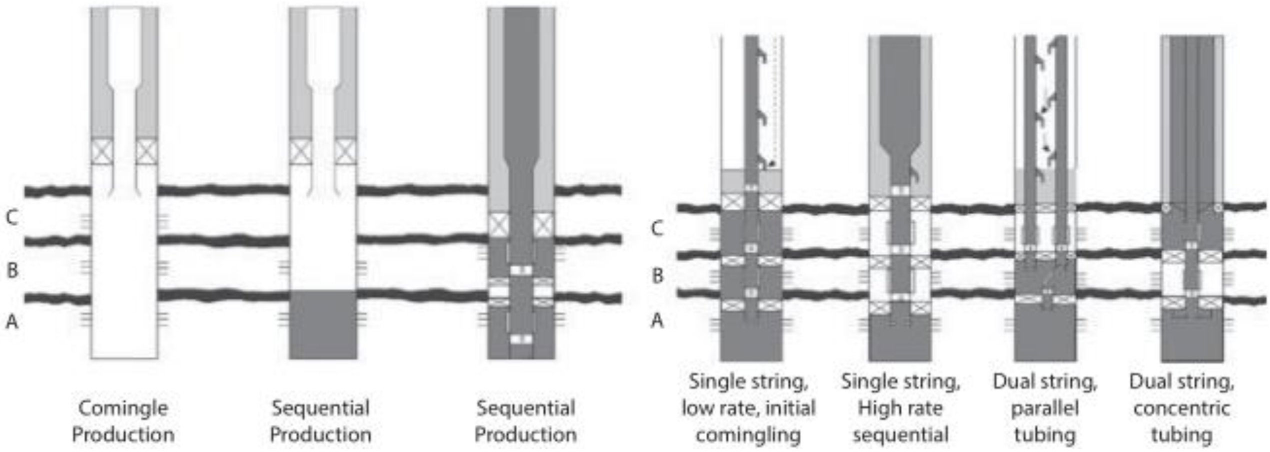

Figure 37: Methods of completing multi-zone wells (*Hossain & Al.Mayed 2015*).

- **Commingled Production**: Means production of oil and gas from more than one pool or zone through a common well-bore or flow line without separate measurement of the production from each pool or zone

- **Sequential Zonal Production:** Completion designers prefer to use single string or single zone completion methods for multi-zone situations because of their simplicity and ease of installation. However, economics, reservoir management and regulatory requirements are subject to this preference. In this process, the zones are drained from the bottom upwards and temporarily suspended or abandoned sequentially and then the next higher zone is completed. If zones are close together, the initial completion may be mounted to allow plugging and perforating each zone by well intervention methods. Nevertheless, there is a trade off in that flow efficiency of the deeper zones and depth access for artificial lift and well killing will be compromised. An option is to conduct a workover pulling the tubing and re-completing by moving the packer depth upwards. (*www.coursehero.com*)

- **Single String Multi-Zone Production:** These methods provide techniques to bring other fresh zones when the first zone experiences production problems. They may also be used for the management of the reservoir by enabling the processing of mixtures or individual parts at different stages of the well life to optimize the full potential of the reservoir (***Figure 37***). Downhole chokes or regulators can be installed to control flow from each zone when commingling to prevent crossflow, reduce excessive gas, etc.

- **Dual String Multi-Zone Production:** Multi-Zone Dual string completions are often used offshore or in stacked reservoirs where there are parallel or concentrated tubes (***Figure 37***). The use of parallel tubes separates the rate of production in the pay zone. This is limited by inflow performance and would not be economical with the previous methods described above. They can often double the individual wells' productivity for a reasonably low-cost increment. In such a case, it is possible to use either parallel or concentrated strings. Concentric strings may produce higher flow capability but obviously no down hole safety valve in the outer tube can be installed. The casing tubing annulus is used by some operators as another flow conduit. However, this is subject to dictating the philosophy of individual operators and regulatory rules. If an artificial lift is required, it would normally require parallel strings.

2. OFFSHORE WELL COMPLETION & PRODUCTION EQUIPMENT

2.1 Introduction
2.2 Well Completion Concepts in Offshore
2.3 Principal Development Methods
2.4 Hydrocarbons field Architecture
2.5 Topsides - FPSO

2. OFFSHORE WELL COMPLETION & PRODUCTION EQUIPMENT

2.1 Introduction

When the well has been drilled, cemented, and cased the next step is about the completion of the well by using equipment that can deliver the maximum amount of oil and gas at a minimal cost. Completing a well is the most critical process of a well's life (*Graf 1981*). The production process, future workover possibilities, well productivity, downhole problems, etc. depends on how the well was completed. Before a completion operation is designed, various factors need to be taken into account:

- Type and volume of produced fluids
- Target zone depth and surrounding environment
- Presence of multiple zones
- Stimulation potential of the well
- Type of artificial lifts (generally gas lift in case of offshore)
- Frequency of workover operations.

Upon evaluating all possible considerations, engineers need to choose from various available completion schemes, ranging from simple open hole completions to complex multilateral completions (*Shashi et al. 2020*). Optimal completions provide solid flow efficiency, data gathering, and flexibility. Completion designs are generally planned before drilling but engineers should be prepared for unforeseen contingencies that may arise in their plan.

2.2 Well Completion Concepts in Offshore

Completion in offshore is referred to in two contexts, a well completion or a subsea completion. Well completions refer to the development of a wellbore to obtain controlled recovery of fluids, whereas subsea completion refers to a system of pipes, connections, and valves that exist on the ocean bottom and serve to gather hydrocarbons derived from individually completed wells and direct them to storage and offloading facility that might be either offshore or onshore. Other than some specialized and innovative completion solutions, offshore completion and onshore completion is not very different. *Most offshore wells are directional and multilateral.* Although the basic configuration of wellheads and trees is also similar to those used on land, these are designed to be compact and lightweight and possess a greater degree of reliable remote control so that they can be controlled remotely in case of emergencies.

2.3 Principal Development Methods

The overall system configuration is primarily determined by the type of well completion, the method of drilling, and the number and position of drilling sites.

The well system can be based on either dry trees or wet trees or a combination of both. The classic version of offshore production facilities comprises of the production platform, well system and export facilities. It's sometimes referred to as a stand-alone approach. Since the field life is often more than 20 years, the facilities will have little value after the end of production and the facilities are therefore in most cases, adapted to the actual case.

Nevertheless, in the case of very small fields, the field life may be shorter, perhaps only 5-10 years. In these situations, it may be beneficial to use a mobile production platform that can be re-used and transferred from one specific area to another. In most cases, the mobile production system will mostly be a ship or a floating platform.

Many projects may already be in operation in a mature environment with several developed areas. It may be very tempting to make use of existing platforms and pipelines (infrastructure) for new small discoveries. It may be possible to drill very long wells from an existing platform to the new discovery or to tie-back new wells to an existing platform (satellite development) (***Hall 1983***). The two main criteria are the field size in terms of recoverable reserves and the distance to the nearest existing infrastructure (platform facilities or onshore facilities).

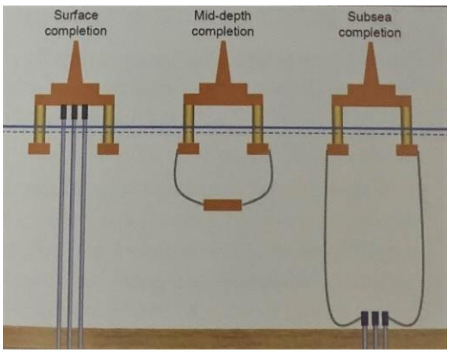

Figure 38: Offshore Well Completion Methods (*Source: University of Stavanger*).

2.3.1 Surface Completion – Dry Trees

The key benefit of this scheme is that the completion is accessible from the drill floor and well re-entry for both light and heavy workover is possible at the surface facility. Its principal limitation is that it confines reservoir access to that achievable from a single location.

2.3.2 Subsea Completion – Wet Trees

Before the start of production, a subsea well is to be completed after drilling and temporarily suspended. A Subsea completion refers to a system of pipes, connections, and valves that exist on the ocean bottom and serve to gather hydrocarbons produced from individually completed wells and direct them to a storage and offloading facility that might be either offshore or onshore (***Singh, 2019***). The emergence of subsea technology has revolutionized the industry's offshore activities and has developed at a remarkable pace in recent years. Overall, surface completion systems are cheaper to manufacture, easier to install, and far less troublesome to maintain than subsea systems. The decision to opt for subsea development is usually made while other context-specific criteria render it demonstrably superior in terms of overall cost-effectiveness. Such criteria include water depth, prevailing climatic and environmental conditions, well numbers, reservoir size and reserve distribution, well maintenance requirements, etc. Conditions that particularly favor the adoption of subsea completion technology include:

- Deepwater fields
- Small/Marginal field or fields with scattered reserve distribution
- Harsh environmental conditions
- Fast track development projects
- Phased development – designed to achieve early production that can then be augmented by later stages of development.

Subsea well completion is reliable in terms of service and cost, and as a result, the number of subsea completions has increased over the years, especially for the development of deep-water fields where subsea completion presents a low cost-development solution in deep water.

Two completion methods are commonly and widely used in the industry, as illustrated in ***Figure 39***:

- *Open hole completion*: Open hole completions are the most basic type. This approach involves setting the casing in place and cementing it above the producing formation. Then continue drilling an additional hole beyond the casing and through the productive formation. Because this hole is not cased, the reservoir zone is exposed to the wellbore.
- *Set-through completion*: The final hole is drilled and cemented through the formation. Then the casings are perforated with tiny holes along the wall facing the formations. The production can then flow into the well hole. The completion design includes the tubing size, completion components and equipment, and subsea Xmas tree configuration. Components of subsea completion equipment include the subsea wellheads and the subsea tubing hanger/tree systems, which will be discussed in the following sections. (*Bai Y. & Bai Q, 2010*).

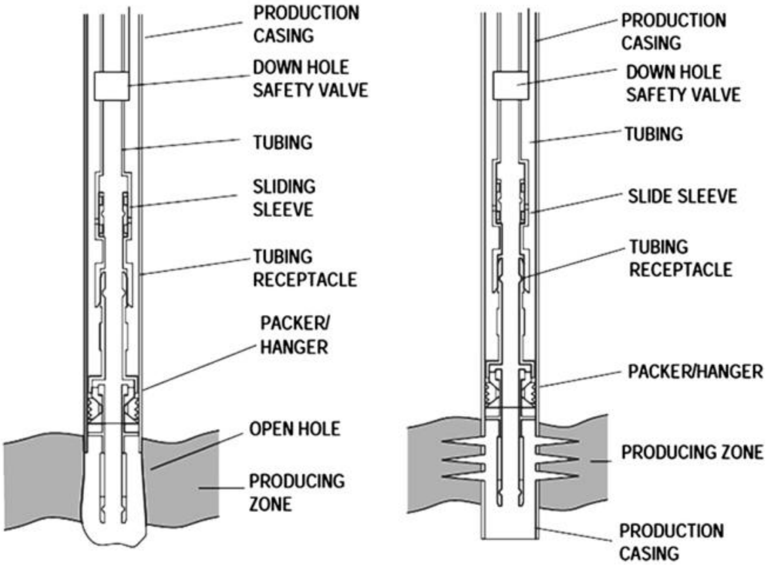

Figure 39: Subsea Completion Methods (*Bai Y. & Bai Q, 2010*).

2.3.3 Completion Equipment

2.3.3.1 Christmas Tree

A Christmas tree *(1.7.4 Installing the Christmas Tree)* is the most important well control equipment used in well completions. It consists of an arrangement of valves, spools, flanges, and connections to control the flow of fluids from the well. Based on the application and environment of use, several types and configurations of Christmas trees are available.

Primarily Christmas tree used offshore is of two types: i) Platform completed (Dry tree), and ii) Subsea completion (Wet or dry tree). Platform completed wells (Dry tree) are similar to those being used onshore (*Singh, 2019*).

2.3.3.2 Production Tubing

Production tubing *(1.7.3 Installing Production Tubing)* forms the conduit for reservoir fluids to flow from the wellbore to the surface. Also, it facilitates wellbore service operations such as wire line, stimulation, and circulation. Typically, tubing is run inside a casing or liner but can also be cemented in slim hole wells as the casing. Depending on the type of completion, one or two tubing strings may be used in the well.

2.3.3.3 Packers

A packer provides a means of sealing the tubing string from the casing or liner, thereby preventing fluid movement between them. This protects the casing from undue stress in the form of pressure differentials, as well as protects the casing against corrosion and erosion from the produced fluids (*Raymond & Leffler 2006*). Because casing used in a well is a permanent component of the completion system, repair/replacement of casing is very complicated and expensive. The packer along with the tubing string is easier to remove and replace. Packers are also used for zone separation as in the case of multiple zone completions.

All packers mostly consist of:

- **Flow mandrel** to provide the flow conduit for production.
- **Resilient elements** to ensure the tubing to annulus pressure seals.
- **Cone or wedges** to assist in the positioning of the slips.
- **Slips** to grip the casing wall and prevent the packer from moving up and down.
- **Hold down buttons** to prevent packer from unseating.

The packer design also provides for a spacer tube that has holes to remove trapped air and bypass ports to circulate out debris settled on the packer and pressure equalization across the packer elements.

The criteria for packer selection must consider:

- Selection/completion strategy
- Rig capacity for fishing/milling

- Fishing requirements
- Well fluid characteristics, H_2S, CO_2
- Bottom hole pressure and temperature

Packers can be single, dual, or triple bore, and are mainly classified as:

Retrievable Packer

These packers are designed simply without needing to be milled out to be unseated and pulled out of the well. Therefore, they all have an integrated mechanism, so that they can be unseated. A retrievable packer is run as an integral part of the tubing string and is set either mechanically or hydraulically and can be released by pulling or rotating the string.

It provides advantages of reuse and saves rig time as milling operation is not required for removing the packer. However, these have a low differential pressure rating, and pressure distribution is also not uniform. As mechanically set packers are temperature-sensitive, care should be taken while using cold fluids during a simulation (***Singh, 2019***).

The mechanically set retrievable packers are set by applying sufficient right-hand rotations to the string and released by a straight pull. Compression-set mechanical packer in ***Figure 41*** is presented downwards. Tension-set mechanical packers in ***Figure 40*** are used when the packer is to be set at shallow depths where required compression cannot be given. Packer configuration in tension-set packer is opposite to that of the compression set, that is, slips at top and rubber elements at the bottom. Before running in the packer, it must be ensured that the rubber elements, spacer rings, dies, slips, and Teflon ring at the top sub are in good condition.

Figure 40: Tension - type retrievable packer (*Singh 2019*).

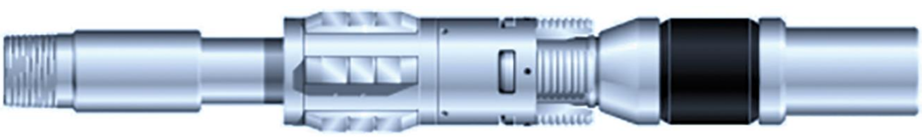

Figure 41: Compression - type retrievable packer (*Singh 2019*).

The hydraulic-set retrievable packers are set by applying a pressure of 1,400–2,000 psi inside the string, thus requiring pump-out plug (POP) to apply pressure. The POP rating depends on well pressure. The ratchet mechanism in the packer stores the setting pressure and enables the elements to remain in an inflated condition. The packer is released through a release ring/screws that shear at an overpull of 20,000 to 30,000 lbs above the pullout weight (***Figure 42***).

Figure 42: Hydraulic-type retrievable packer (*Singh 2019*).

Permanent Packer

Normally, once set, the permanent packer, is regarded as part of the casing and can only be removed destructively by milling. The completion string can be engaged for providing the flow conduit or removed from the packer for well killing. Permanent packers can be set mechanically, hydraulically, or electrically through wire line.

These packer types are recommended for when long-term completion, high-pressure differential, maximum dependability, and large packer bore are required (***Figure 43*)**

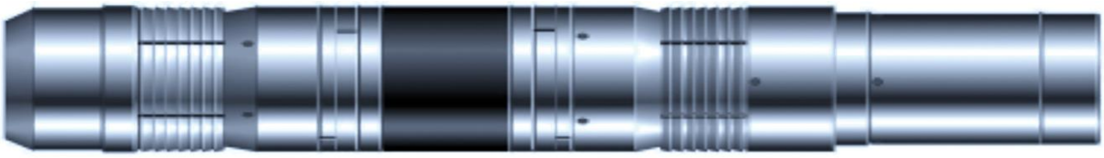

Figure 43: Permanent packer (*Singh 2019*).

This kind of packer is simple in design and does not require complex mechanisms. It is extremely durable and is able to withstand severe mechanical strains and high differential pressures. It also has a range that provides the largest inside for a given casing diameter. It is flexible in terms of potential tubing packer connections and can be left in the well to modify production equipment during workover operations.

The greatest drawback is that only be extracted by milling or drilling out. This means that after the production wellhead has been removed and the tubing pulled out, a drill string-type assembly must be used. (***Raymond & Leffler 2006***). Another point to highlight is that if the tubing does not move for a long time, the production tubing sealing elements eventually adhere to the packer's inner mandrel. In contrast, too regular movement causes the sealing elements to be prematurely eroded.

In any case, in deep wells this type of packer has no counterpart in deep wells and is also mostly used in gas-producing wells.

Inflatable Packer

Inflatable packers are run through the tubing string, either on wire line or coiled tubing, and inflated to the required size. The pressure rating of such packers is less. These packers are used in straddle completions and for open hole testing (***Figure 44***).

Figure 44: Inflatable packer (*Courtesy: Drillingcontractor.org*).

2.3.3.4 Blast Joint

Reservoir fluids entering the wellbore through perforations may display a jetting behavior that can erode the tubing string at the point of fluid entry, and ultimately may cause tubing failure. The blast joints are pipe joints of 20-30 ft long with a wall thickness greater than the tubing and are run in the string to be opposite of the perforations. The blast joints delay the erosional failure at the point of entry of fluids into the wellbore.

Figure 45: Blast Joint (*Courtesy: peakcompletions.com*).

2.3.3.5 Flow Coupling

A short piece of pipe that has a wall thickness greater than the tubing string is a flow coupling. It is used to delay the failure caused by erosion wherever turbulent flow is anticipated such as around a landing nipple or subsurface safety valve (*Perrin et al. 1999*). The flow couplings are available in 3–10 ft length, and length of flow coupling for a particular application depends on how quickly turbulent flow is expected to dissipate, as well as the abrasive nature of the fluid.

2.3.3.6 Seating Nipple

Seating nipples are located at various depths in the tubing string. The seating nipples enable various wire line intervention jobs for flow control. Some of these jobs include shutting the well for testing the tubing string, circulation, pressure equalization, operation of subsurface safety valve when hydraulic control is lost, and installation of downhole chokes, (*Allen, 1989*).

2.3.3.7 Landing Nipple

A landing nipple is a short portion of internally machined thick-walled tubing that provides a locking profile and at least one packing bore. It offers a profile at a particular point in the completion string to locate, lock and seal subsurface flow controls either through wire line or pump-down technique.

2.3.3.8 Expansion Joint

Expansion joints are used to compensate tubing movement caused by temperature and/or pressure changes during treatment or production. These are available in various stroke lengths.

2.3.3.9 Safety Joints

Safety joints are used between the packers in multiple completions and selective completion using hydraulic single string packers. The shear pin in the safety joint enables stuck tubing to be sheared off. However, because it introduces a weak joint, its use should be restricted, wherever possible.

2.3.3.10 Safety Valves

- Surface Safety Valves (SSVs). Surface safety valve (SSV) is a hydraulically actuated fail-safe gate valve for producing or testing oil and gas wells with high flow rates, high pressures, or the presence of H_2S. The SSV is used to quickly shut down the well upstream in the event of overpressure, failure, a leak in downstream equipment, or any other well emergency requiring an immediate shut down.

Figure 46: Hydraulic Surface Safety Valve (*Courtesy: ccscpetro.com*).

- Subsurface Safety Valves (SSSVs). A safety device installed in the upper wellbore to provide emergency closure of the producing conduits in the event of an emergency. Two types of subsurface safety valve are available: Surface controlled and subsurface controlled. In each case, the safety valve system is designed to be fail-safe, so that the wellbore is isolated in the event of any system failure or damage to the surface production control facilities. (***https://www.glossary.oilfield.slb.com***).

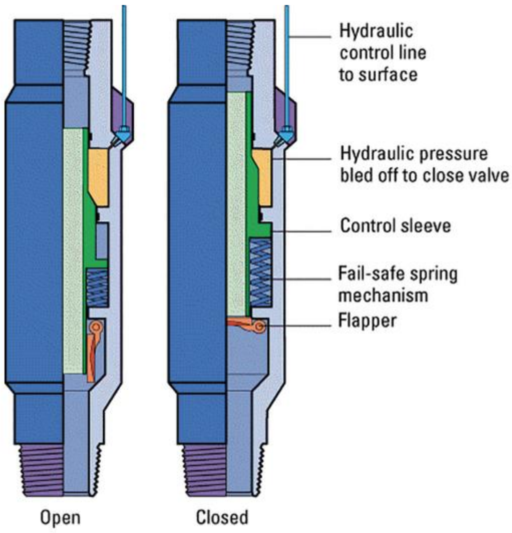

Figure 47: Subsurface Safety Valve (*Courtesy: glossary.oilfield.slb.com*).

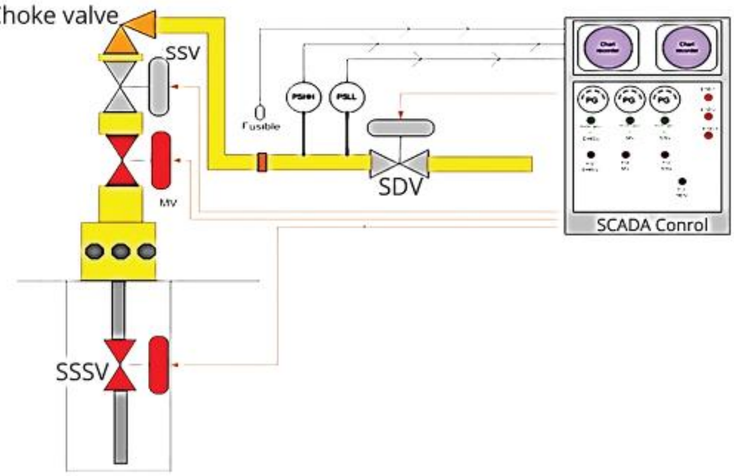

Figure 48: A schematic of safety valves and control (*Courtesy: peakcompletions.com*).

2.3.3.11 Circulating Valves

Tubing to annulus communication is required to circulate fluids in a well, treat a well with chemicals, inject fluids from the annulus into the tubing string, or produce a zone that is isolated between two packers. Such tubing to annulus access is provided in the completion string through various circulating devices.

Sliding Sleeve

This type of circulating device is very popular and is better known under the name of sliding side door or sliding sleeve, SSD or SS. The principal circulating devices are sliding sleeves that have the capacity to circulate a well and produce multiple reservoirs.

A sliding sleeve is a cylindrical device with an internal sleeve and outer body bored to provide appropriate openings. The inner sleeve is moved using a wire line shifting tool. When the sleeve is moved and matched with openings in the outer body, it creates a circulation path between tubing and annulus. Some of the typical applications for which the sliding sleeves are used are for displacing fluid, selective testing, treating or production in multiple completion, killing by circulation, pressure equalizing, etc (***Figure 49***).

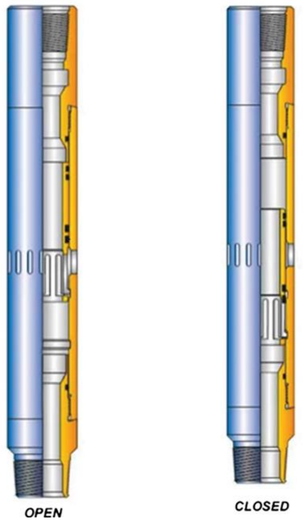

Figure 49: Sliding Sleeve (*Courtesy: peakcompletions.com*).

Side Pocket Mandrel

Side pocket mandrel has a polished receptacle/pocket on one side that can accommodate downhole tools lowered by wire line. Side pocket mandrels are placed in the tubing string at a location wherever required (***Figure 50***). The mandrels are also used to inject chemicals through the annulus into the tubing: demulsifying agents and corrosion inhibitors in particular. This can be achieved by equipping the mandrels with injection valves opened by a defined value of annulus overpressure.

Figure 50: Side pocket Mandrel (*Courtesy: peakcompletions.com*).

The main benefit of such a system is that the seals that surround the communication ports are held in the side pocket by the tool placed and are easy to replace. The fact that the side pocket mandrel causes no diameter restrictions in the tubing for production or running by wireline, snubbing or coiled tubing tools is also appreciated (***Perrin et al. 1999***). The major disadvantages are, first of all, a limited cross-sectional area for contact with the annulus (designed for gas), which does not allow for very high fluid flow rates. Furthermore, substantial additional outside space is needed with regard to the tubing diameter (in particular, mandrels for large tubing diameters are not available on the market), which is not automatically compatible with a casing that is technically or economically appropriate.

Function Requirements

The subsea wellhead system should:

- Provide orientation of the wellhead and tree system for the tree-to-manifold connection.
- Interface with and support of the blowout preventer (BOP) and Xmas tree system.
- Accept all loads placed on the subsea wellhead system from drilling, completion, and production operations, inclusive of thermal expansion. Particular consideration should be paid to the horizontal tree concept where the BOP is latched on top of the Xmas tree.
- Ensure that the low-pressure conductor housing and high-pressure wellhead housing are balanced, compact and longitudinal.

2.3.4 Subsea systems tied-back to facilities in shallow water or onshore

The key features of this system are:

- The position of the X-mas trees on the sea-bed, either as separate satellite wells or in a multi-well template configuration.
- Tie-back of the subsea development to a remote existing production platform or onshore facilities, either via independent flowlines from separate satellite wells, or through a single combined output flowline from a subsea manifold. (***Kassinis 2015***).

This scheme provides the principal advantage of removing the need for a dedicated local surface production facility, likely in deep water, thereby enhancing the economics of exploiting relatively small field technologies.

2.3.5 Mid-depth Completion

This is a form that has been proposed but has not yet been introduced. The key features of this scheme are:

- The placement of the X-mas trees on a self-built foundation below sea level.
- Individual tie-back of seabed wells via rigid risers to the buoyant structure.

- Transfer of the commingled generated fluids to/from the surface facilities via a versatile riser mechanism.
- Control umbilical installed as a flexible riser from the surface facility.
- Removal of the wells from the topsides installations, thus simplifying the interface facility resulting from comingled production flow.

It is envisaged that the flexible piping network from the mid-depth plant would be terminated at the surface site (***Gatlin 1960***). The self -buoyant system will potentially be found at any water depth between the seabed and the surface (***Palmer & King 2008***). Place of X-mas trees near the surface, usually 100 to 200 m below sea level as a 'near surface completion', would have the following advantages:

- The X-mas trees are easily accessible by diver interference for installation/maintenance.
- Light workover operations conducted from a dynamically placed (DP) vessel with extreme workover performed from a semi-submersible rig, without the need for a long workover riser.

2.4 Hydrocarbons Field Architecture

The development of the field architecture for offshore projects is crucial, especially in the case of deep water. Choosing the optimal architecture must address and reconcile the competing requirements of reservoir engineering, drilling system and timeline, early production (if applicable), suitable well trajectories, flowline and pigging requirements, subsea well control, installation strategies and intervention plans. (***Kassinis 2015***). Bathymetry in the field area also clearly affects architecture. This would imply that the optimal design represents the opportunities available to further optimize drill center positions after the early well deployments have taken place. The reservoir area will determine the number of drill center locations needed to exhale the field to optimum effect. The field architecture also has to address the locations for drill centers and the number of wells at each center, to adequately drain the field. These drilling centers also serve as the main hubs in the field architecture. They would be the focal points for the manifolding and onward transport of produced fluids to the field center facilities, as well as for the distribution of chemicals, water injection and gas lift streams etc. Drilling centers also serve as the main hubs for the control system architecture, for the location of control pods and termination of umbilical.

2.5 Topsides - FPSO

The name says it all. Topsides-the place atop the platform where the drilling and processing equipment sit, where scores of auxiliaries continuously labor away, and where the crew makes its temporary home. An FPSO (Floating Production Storage and Offloading) facility unit is a floating vessel used by the offshore gas and oil industry for the processing of hydrocarbons and storage of oil (or condensates). An FSPO vessel is designed to receive hydrocarbons produced from nearby platforms or subsea templates, process and store oil (or condensates) until it can be offloaded onto a tanker or, less frequently, transported through a pipeline. FSPOs are favored in frontier offshore regions as they are easy to install and do not need a local pipeline network to export oil. FPSOs can be a modification of an oil tanker or can be a vessel built specifically for use. A vessel used solely to store oil, without processing it, is referred to as floating storage and offloading vessel (FSO). The FSPO consists of a hull design, similar to that of a ship, to support the Topsides.

FPSO Design
30.000 – 35.000 tons
80 - 150 MW installed power generation
200.000 – 400.000 barrels per day of production
15 modules

Table 9: Topside figures (*Courtesy: Kassinis*).

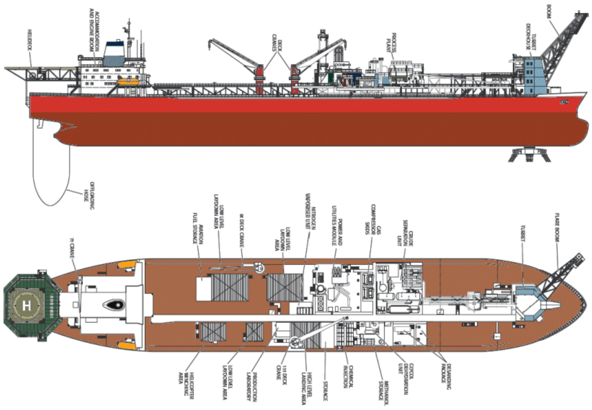

Figure 51: FPSO vessel and its modules (*Courtesy: www.maritime-executive.com*).

2.5.1 Upstream Pipelines

Upstream Pipelines are used for the transfer of oil and gas from the production field directly to the processing plant or terminal (i.e. oil refinery or a liquefaction plant, or gas processing plant). Upstream pipelines could be onshore (land surface, or underground) or offshore (subsea). There could also be a combination of offshore and onshore pipelines (***Fanchi & Christiansen, 2017***). According to the relevant European Gas Directive for the Internal Energy Market (2009/73/EC): '*Upstream Pipeline Network includes any pipeline or network of pipelines operated and/or designed as part of an oil or gas production project, or used to transport natural gas from one or more of these projects to a processing plant or terminal or final coastal landing terminal'*

Receiving (landfall) facilities provide onshore reception and processing of gas coming from an (offshore) upstream field. These facilities include the reception (subsea pipe landfall), the slug catcher for gas/water/condensate separation, the flare, fluid heating, liquid condensate handling facilities, chemical injection and chemical storage facilities. A typical metering bench consists of the metering unit with lines fitted with a turbine or volumetric meters, proving a test loop, an automatic on-line sampler, computers and a control system.

Figure 52: Receiving Facilities (*Source: www.oilandgasmiddleeast.com*).

2.5.2 Subsea Production Systems

'Subsea' is a general term often used to refer to equipment, technology, and methods used for exploring, drilling and developing oil and gas fields below the ocean floors. Subsea can refer to 'shallow' or 'deep' water. 'Deepwater' is a term often used to refer to subsea projects in water depths of 300 m and deeper. In such cases subsea is used in combination with floating platforms. 'Shallow' is used in shallower depths. In such situations subsea is often used in conjunction with fixed platforms. Subsea technology applies to all products and services needed for the installation and operation of production facilities on the seabed.

Subsea Production Systems can be used to develop reservoirs, or parts of reservoirs, requiring the drilling of wells from more than one location. Deepwater conditions, or ultra-deep-water conditions, may dictate the development of a field using a subsea production system, since traditional surface facilities such as on a steel-coated jacket, might be either technically unfeasible or uneconomic due to the depth of the water. Specialized equipment is required for the development of subsea oil and gas fields. The equipment must be reliable enough to protect the environment and make the exploitation of subsea hydrocarbons economically feasible.

The installation of such equipment requires specialized and costly vessels, to be fitted with diving equipment for relatively shallow work (i.e. at less than about 180m), and robotic equipment for deeper water depths. Consequently, any requirement to repair or intervene with installed subsea equipment is usually very costly. Intervening with installed subsea equipment requires particular caution and techniques, due to the complexity of the systems and the nature of the underwater environment.

Subsea production systems can range in complexity from a single satellite well with a flowline connected to a fixed or floating offshore platform or an onshore installation, to several wells on a prototype or clustered around a manifold and transferred to a fixed or floating facility or directly to an onshore facility ***(Fraser et al 1991).*** Subsea wells have been used for several applications. Single satellite wells can be directly linked-back to platforms, but if there are many wells, they are normally tied-back via a common manifold.

'Umbilical' are used to transfer hydraulic chemical media, low and high-power media, signal media and gas lift media. 'Flying Leads' distribute hydraulics, chemicals, electrical power and field communication signals around the field between the various pieces of equipment (e.g. trees, manifolds, pumps etc.), through the umbilical. Hydraulic Flying Leads (HFL) convey hydraulics and chemicals between units, while Electrical Flying Leads (EFL) transfer electrical power and communication signals between units.

'Flowlines' are submarine pipelines, from the wellhead to the riser base, carrying oil and gas products ***(Szilas 1975).*** Flowlines piping types include a single pipeline with corrosion and (where applicable) weight coating pipelines, single wet insulation pipelines, pipe-in-pipe (double wall) pipeline, bundles and flexible pipeline.

Any active fluid treatment performed on or below the seabed is the Subsea processing which involves separation (gas/liquid), cooling, heating, filtering (sand and solid separation), pumping (liquids, multiphase), gas treatment, compression (gas), raw seawater injection, de-hydration and chemical injection. Subsea processing is sometimes preferred to surface processing (on a platform) because it offers a less expensive solution. Subsea processing has become a viable solution for fields in harsh conditions where processing equipment might be at risk on the water's surface.

Subsea Architecture Terms

Topsides	FPSO (Floating Production, Storage and Offloading)
SURF	Subsea Umbilical, Risers and Flowlines
SPS	Subsea Production System
SSPS	Subsea Separation and Production System
OLS	Oil Loading System

Table 10: Subsea Architecture Terms (*Courtesy: Kassinis*).

2.5.2.1 Risers

The role of a 'riser' is to provide conduit(s) between sea floor equipment and surface equipment for the conveyance of hydrocarbons or fluids injected. In some cases, risers can be considered simply as a continuation of the subsea flowlines from the riser base on the sea bottom to the surface facilities.

Figure 53: Complete Riser Joint (*Courtesy of Offshore Magazine, 2001*).

For floating production units, the risers must be sufficiently stable to withstand the vibrations produced by waves, wind and current. Risers are therefore tailor-made for each production unit.

Production and export risers take six different types to and from the production platform: attached risers, pull tube risers, steel catenary risers, top tensioned risers, flexible riser configurations and tower risers.

Attached Risers

The riser is pre-constructed in sections. The riser's sea bottom end is connected to the nearby inbound flowline or outbound pipeline, then assembled and inserted piece by piece on the structure in pre-placed clamps. ROVs with electro-hydraulic tools make the connections or divers do the work.

Pull tubes

The pull tube, a few inches wider than the flowline or pipeline, is generally pre-installed in the structure. Attached to a wire rope threaded through the pull tube is a flowline or pipeline laid on the seabed floor (***Leffler et al. 2003***). The wire rope is winched up to the topsides by the pull cable, at which point the flowline or pipeline inside the tube becomes the riser. This method operates well when the pipe is pulled straight from the lay barge and inserted into the pull drain.

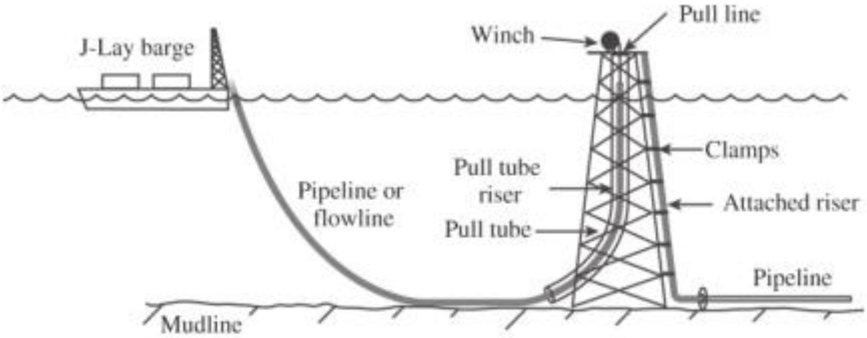

Figure 54: Attached and pulled-in tube risers (*Leffler, 2003*).

Steel catenary risers

Steel catenary risers are an innovative approach to the riser challenge of connecting to floating production platforms in deep-water (***Leffler et al. 2003***). These risers can be installed by setting a predetermined length of pipe, making enable connections. They withstand a certain amount of output platform rotation, making them useful for TLPs, FPSs, FPSOs, and spars, as well as fixed platforms, compliant towers, and gravity structures. However, excessive motion can cause metal fatigue at or near the touchdown point and at or near the top support.

Top tensioned risers

Top-tensioned risers offer a suitable solution for some TLP and spar applications. In this application, the flowline or pipeline terminates at a junction point beneath the structure. (***Figure 55***). A straight riser is run down from the platform and either ends in the same junction structure or its own junction structure, whereupon a short pipe section installed with the aid of an ROV connects the riser and flow line.

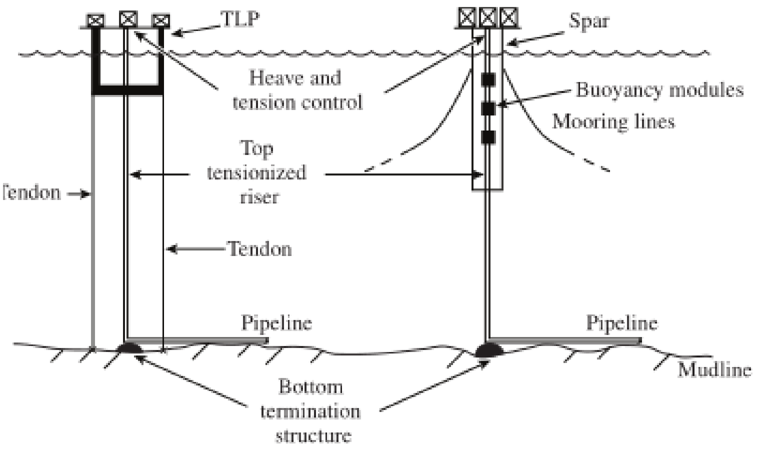

Figure 55: Top tensioned riser (*Leffler, 2003*).

Since the riser is attached to the sea floor, and under the influence of winds, tides, and waves, the TLP or spar is free to move laterally there is vertical displacement between the top of the riser and the point where it connects to the TLP or spar.

Riser tower

The riser tower consists of the following:

- Four production risers (8in)
- Four gas lift risers (3in)
- Two gas/water injection risers (8in)

- Two service line risers (2in)

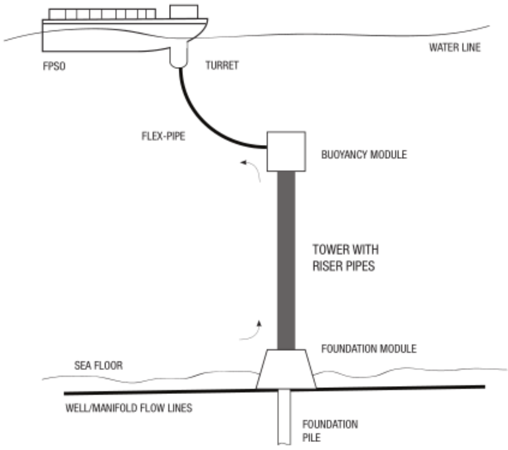

Figure 56: Riser tower held upright by a buoyancy module, connected via a flexible pipe jumper (*Leffler, 2003*).

Flexible risers

Due to its beneficial bending characteristic, a flexible pipe is often used to make the connections between the production equipment on floating systems and the production and export risers. Because of these same bending characteristics, these flexibles are also finding more and more use as the primary risers (***Laik 2018***). Besides the usual, free-hanging catenary riser, (***Figure 57).*** shows several other configurations: lazy S, steep S, steep wave, and lazy wave.

The specific selection depends on the expected motions of the production vessel and available installation equipment. All configurations require providing buoyancy modules or cans at selected places on the flexible pipe to force a specified shape, and they all have the net effect of minimizing the stress and wear and tear on the pipe at both the touchdown point and at the platform connection.

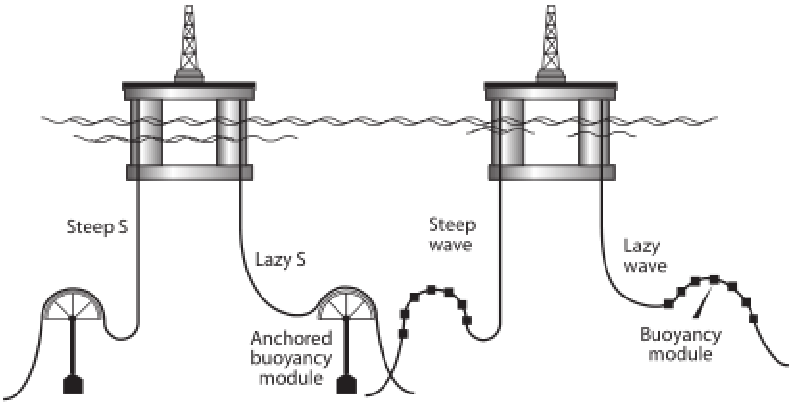

Figure 57: Some flexible riser configurations (*Leffler, 2003*).

Selecting a Riser System

Some risers predominate for the different systems of production. The attached and the pull-tube risers are most popular for fixed platforms and compatible towers. For concrete gravity structures, attached and pull tube risers make most sense (***Laik 2018***). For the floating systems, FPS, TLP, FPSO, and spar, the attached riser and pull tube don't work because they cannot accommodate the lateral excursions. The steel catenary riser and flexibles operate at the floater for almost every occasion. The top tensioned riser works for the TLP and spar only. The riser tower method, which also has many variations, can be used with all floating systems, particularly for ultra-deep-water.

3. PRODUCTION LOGGINGS & LOGGING TOOLS

3.1 Production Loggings
3.2 Production Logging Tools
3.3 A typical production logging Job Sequence

3. PRODUCTION LOGGINGS & LOGGING TOOLS

3.1 Production Loggings

Production logs traditionally encompass several well logging techniques that run on completed injection or production wells, intending to evaluate the well itself or the reservoir performance. Production logs were first used in the 1930's for measuring the temperature of wells but over the decades other measurements such as pressure, fluid density and hold up were developed consequently [12]. The first spinner-based flowmeters appeared in the 1940's. They were complemented by fluid density and capacitance tools in the 1950's. Together with some PVT correlations and Flow Models, these were the elements required to perform what we will call today a 'classical' multiphase interpretation. The first probe tools were introduced in the 1980's. In the late 1990's, these probes were packaged into complex tools that began to measure the velocity and holdup distributions across the pipe to address the challenges of understanding the flow in complex, horizontal, near horizontal wells.

Wellbore parameters like wellbore diameter, hole integrity, caving, formation porosity, permeability, resistivity and some other characteristics are measured by traditional wire line logging. This measurement also may be gained by logging while drilling. Production logging is applicable when the production is started. The general purpose of production logging is to evaluate the behavior and type of fluids within the wellbore during either production or injection operations.

Although there are some logging services available to the industry which provide this type of information. A standard group of production logging tools like spinner flow meter device, fluid identification tools, borehole pressure and temperature measurements along with natural gamma ray and casing collar locators is used for the operation. Production logs are simply a combination of a wide range of sensors, measurement tools that are used with proper methods of analyzing and help the reservoir management team such as drilling engineers, production engineers and reservoir engineers to obtain their required data of measurement. Production logging measurements usually consist of several types of logs. They are temperature, fluid density, fluid capacitance, pressure, and spinner-flow meter, along with standard casing collar locators and gamma ray logs. These measurements are usually made in a single logging run for reducing rig time, and make all measurements under the same wellbore conditions.

The production log is dissimilar to other logs. Several geophysical logs are run in the well to measure some properties before production started and during exploration and development stages. Production logging is a cased hole logging technique. This is the logging procedure to gather wellbore fluids data during production or injection. When the wellbore is completed, production logging tools are run.

3.1.1 What Production Logging is Used for

Production logging tools are used for the measurement which involves a wide range of sensors and measurements tools. This technique has also interpretation tools that evaluate the formation properties, analyze the formation fluid movements inside and outside of the wellbore and estimate the production flow rate for each layer of the formation (*Davarpanah et al. 2018*).

Most of the logs like sonic log, resistivity log, density log, neutron log and rest of the logs are used to determine the wellbore parameter as well as formation fluid characteristics up to the wellbore completion. This is the basic difference from production logs. Production logs are run only when the completion is done, and production is started. During enhance recovery, the production log is run to observe the movement of the fluid near and in the wellbore. The production logging tools are small in diameter and are run through tubing for evaluation of the well as it is producing.

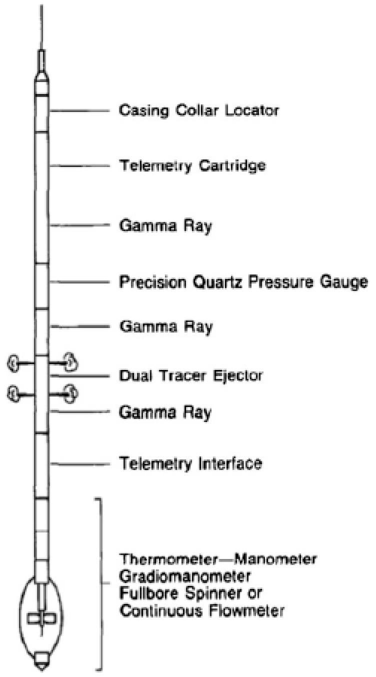

Figure 58: PLT, simultaneous production logging tool (*Liu 2017*).

Production Loggings enables a certain number of operational problems to be detected or quantified: formation cross-flow, channeling of undesired phases via poor cement, gas and water coning, leakage of casing, corrosion, non-flowing perforations.

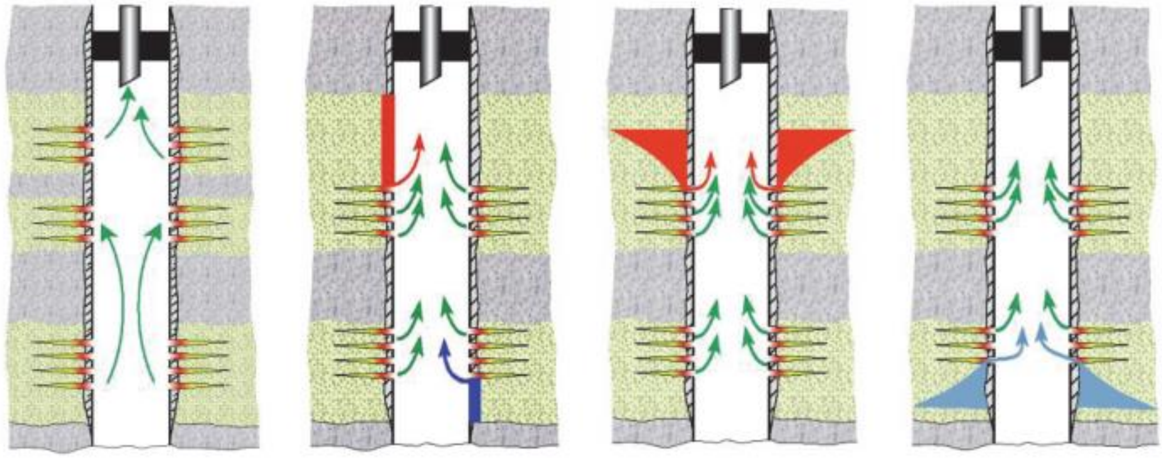

Figure 59: PLT, simultaneous production logging tool (***Courtesy:*** *Schlumberger*).

Production Log Application

There are many applications of production logging in both open hole and cased hole environments.

- Lost circulation zones and underground blowouts in open hole conditions are identified.
- Cased hole flow performance is also measured by the production log.
- Locates top of cement
- Evaluates gravel pack quality, location of perforations
- Determine comparisons of permeability, locations of leaks
- Hold-up behaviors like water/oil/gas hold up for several depths are determined by production logs data.
- Besides leakage identification between production tube and production casing is also determined by production logs.
- Production casing integrity is checked by production logs.
- The effect of enhanced recovery is also observed by the production logging procedure.

Production Log Running Situations

Production logging depends on some criteria. Production log can be run in some special scenarios and several conditions of the reservoir which are mentioned below (*Enzendorfer 2007*).

- New well: Production logging can be applied in new wells to evaluate the initial production of the well.
- Unstable well: Production log is used in the well which production is suddenly decreased or suddenly increased.
- Problem determination: Production log should be run periodically in the production well to make sure that any problems such as gas or water coning or fingering remain or not before a serious reduction in production occurs.
- Injection wells: The production log is run in the injection well to determine the injecting fluid entry point to the formation (*Bateman 2015*).

Beside production log can be applied in the multi-layers producing wells, before and after the acidizing procedures of a well and unreasonable water and gas production wells (*Karakas & Tariq 1988*).

3.2 Production Logging Tools

Modern production logging tools may be categorized into three general groups as making measurements of:

- Formation properties through casing and/or tubing.
- Fluid type, flow rate, and movement within the casing/tubing vicinity.
- The status of the completion string

3.2.1 Tools for formation properties

Tools that measure formation properties from within a completed well include:

- Pulsed neutron logs: (TDT, NLL, TMD)
- Gamma ray logs: (GR)
- Natural gamma spectra logs: (NGT)
- Inelastic gamma logs: (IGT)

- Carbon/oxygen logs: (C/O, GST)

All have a common characteristic; they depend on interactions of nuclear particles (neutrons) and/or radiation (gamma rays) that can pass through steel casing.

3.2.2 Tools for Fluid Typing and Monitoring

Tools that distinguish oil from gas and water and monitor their flow rates include:

- Flowmeters: packer, basket, and continuous
- Temperature: absolute, differential, and radial
- Fluid density: gradiomanometer and gamma–gamma
- Radioactive tracers
- Noise logs

Each of these devices will be discussed and their uses illustrated with field examples.

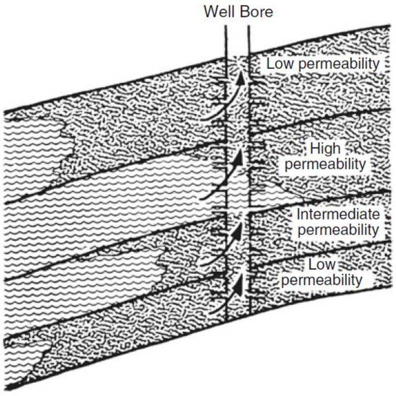

Figure 60: Irregular water encroachment and early breakthrough in high-permeability layers (*Cesak & Schultz 1956*).

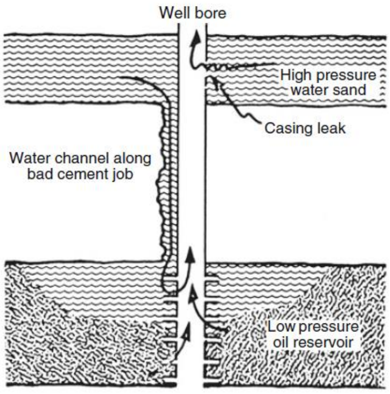

Figure 61: Water production through casing leak and channel leak (*Cesak & Schultz 1956*).

Flowmeters (spinners)

A spinner flowmeter is an impeller that is placed in the well to measure fluid velocity in the same manner that a turbine meter measures flow rate in a pipeline. Like a turbine meter, the force of the moving fluid causes the spinner to rotate. The rotational velocity of the spinner is assumed linearly proportional to fluid velocity, and electronic means are incorporated into the tool to monitor the rotational velocity and sometimes direction. A significant difference between a spinner flowmeter and a turbine meter is that the spinner impeller does not span the entire cross-section of flow whereas the turbine meter impeller does, with a small clearance between the impeller and the pipe wall.

A properly run spinner-flowmeter log should yield a reliable flow profile in single-phase flow in a constant-diameter well-bore. The spinner-flowmeter, however, is susceptible to mechanical problems, and the quality of the log depends strongly on the logging procedure and the care taken in running the log. If the well-bore cross-sectional area is variable, such as in an open-hole completion, a caliper log is needed to interpret a spinner-flowmeter log. In multiphase flow, a spinner flowmeter is often a very poor log, though in some instances it will perform well (*Liu 2017*).

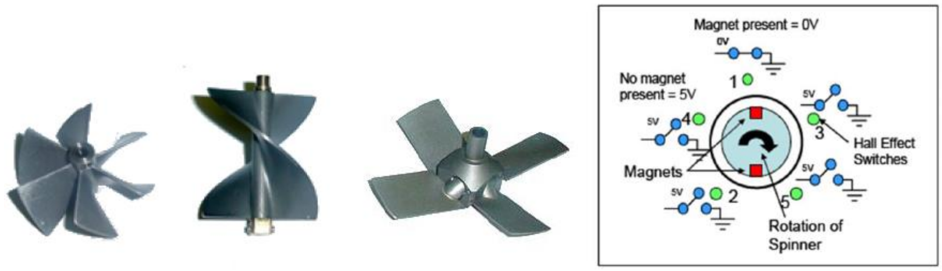

Figure 62: Various types of spinners – Schematic of the Hall effect (***Courtesy:*** *Sondex*).

The spinners are packaged in several types of tools. There are three main types of flowmeters: i) Incline, ii) Full-bore and iii) Petal Basket.

Figure 63: Incline, Full-bore and Petal Basket flowmeters (***Courtesy:*** *Sondex*).

- Incline flowmeters have small diameters and can be used to log in completions with restricted diameters (tubing, scaled up wells etc.). Conversely, they have a low sensitivity and must be selected to log high rates / high velocity wells. Because of the small spinner size, a good centralization of the tool is required.

- Full-bore flowmeters have larger blades that are exposed to a larger part of the flow cross-section. The blades collapse to pass the tubing and other restrictions. They expand and start turning when the cross-section becomes large enough. Full-bore flowmeters have good sensitivity and can be run for a wide range of flow rates and velocities. There may be sometimes issues with injectors, where the blades may collapse when the flow coming from above becomes too large. A lot of tools combine the full-bore spinner with an X-Y caliper that will protect the blade and expand/collapse the tool. Such a set-up combining two tools in one, creates a more compact tool string.

Figure 64: PFCS Full-bore flowmeter with built in X-Y caliper (***Courtesy:*** *Schlumberger*).

- Petal Basket flowmeters concentrate the flow towards a relatively small spinner. They are very efficient at low flowrates. However, they are not rugged enough to withstand logging passes, and are designed for stationary measurements and the tool shape often affects the flow regime.

Density tools

In single-phase environments spinner measurements may get us flow rates. However, when several phases flow at the same time the problem becomes under-defined, and one needs to get additional measurements to discriminate possible solutions.

To schematize we will need at least one more tool to get two-phase interpretations, and at least a third one to get three-phase interpretations. Without the minimum number of tools, additional assumptions will be needed.

If there are more tools than necessary, one will not be able to match all measurements exactly at the same time, because of the nature of the calculations done.

The first natural complement of the spinner type flowmeters is density tools. In a two-phase environment, measuring the fluid density will allow discriminating the light phase and the heavy phase, provided that we have a good knowledge of the PVT. Four main tools that may give a fluid density: gradiomanometers, nuclear density tools, tuning fork density tools (TFD) and pressure gauges after differentiation.

Figure 65: Schematic of a gradiomanometer, nuclear density tool, TFD tool, pressure differentiation (***Courtesy:*** *Schlumberger*).

- <u>Gradiomanometer Tool</u>

  The gradiomanometer tool uses the pressure differential between two bellows to infer the density of the fluid between the sensors. A schematic of the bellows tool is shown in ***Figure 66.*** The bellows compress with pressure and a rod moves in proportion to the difference in compression between the two sets of bellows. A magnetic plunger on the end of the rod generates a signal proportional to the rod movement in a transducer coil. The coil output is calibrated in terms of fluid-density. In deviated wells, the gradiomanometer reading must be multiplied by the cosine of the deviation angle to correct the hole deviation effect.

$$\Delta\rho = \rho g \Delta h = \rho g d \cos\theta \tag{3-1}$$

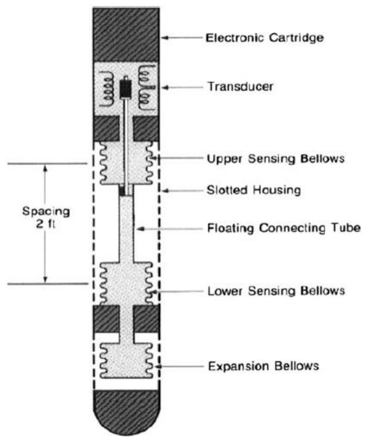

Figure 66: Gradiomanometer fluid-density tool (***Courtesy:*** *Quartzdyne*).

where d, the spacing between the bellows, h, deviation from vertical, Dh, vertical height between the bellows, g, acceleration of gravity. Under the hydrostatic condition, that the pressure gradient in multiphase flow can be written as

$$\Delta\rho = \Delta\rho_{\mathrm{HH}} + \Delta\rho_{\mathrm{f}} + \Delta\rho_{\mathrm{E_k}} \tag{3-2}$$

where $D\rho_{HH}$, hydrostatic head of the flow stream, $D\rho_f$, frictional pressure gradient, and $D\rho E_k$, pressure gradient resulting from kinetic energy change. Assuming that $D\rho E_k$ is negligible and that $D\rho_f$ is small compared to $D\rho_{HH}$, then $D\rho$ can be given by Eq. (3.1)

- Nuclear density tool

From one side of a chamber, this tool sends gamma rays and detects them on the other side. Only a function of the fluid density within the chamber would be the gamma ray attenuation. There is no correction needed for friction or deviation. The concern is whether the fluid present in the chamber is representative of the flow through the pipe. The tool shows very quickly its limitations in deviated wells with segregated flow. There is also a concern with the presence of a radioactive source.

- Tuning Fork Density (TFD)

By testing the fluid's effect on a resonant fork, the TFD works. There is no need to fix frictions and deviation as far as nuclear density instruments are concerned. This is a pretty recent type of tool and we will have to wait a little longer to assess its effectiveness.

- Pseudo – density from pressure

With regard to the measured depth, we determine the derivative of the pressure and then have to compensate for friction and variance. This would usually be used on the pressure obtained during slow passes.

Capacitance and holdup tools

To overcome the problems inherent in the ability of fluid-density tools to distinguish between oil and water, another class of tools was developed to measure water fraction more accurately in multiphase flow. The devices are based on an electrical-capacitance measurement and are sometimes referred to as hold up meters or water-cut meters.

Capacitance tools are essentially coaxial capacitors. By application of a voltage potential between a central electrode and the outside of the logging tool, the capacitance of the device is determined. Because the measured capacitance is a function of the dielectric constant of the fluids in the sample chamber, the capacitance tool provides a measurement of dielectric constant.

- Capacitance tools for water holdup: This is a tool based on the difference of dielectric constants between water and hydrocarbons. This tool will provide correct measurements when the water holdup is less than 40%. The tool response, given as a calibration curve, is unique and highly non-linear.

  This tool is also subject to delays in the response by filming (down passes) and wetting effects (up passes), hence the risk of the wrong positioning of the fluid contact.

Figure 67: Capacitance tool (***Courtesy:*** *Schlumberger*).

- Gas holdup tools (GHT)

  This tool is designed to calculate the fraction of the gas in the fluid. A transmitter emits gamma ray, so the measurement discriminates the gas based on the amount of backscatter, knowing that the gas has a low electron density and a low back scatter. The tool provides a measurement across the wellbore without the influence of the formation behind the casing. It is not susceptible to deviation and requires no friction correction. The negative is that it uses a radioactive source and needs a centralized operation. Raw counts have to be checked by the pipe ID, prior knowledge of certain PVT properties, and results may be influenced by scale.

Pressure and Temperature sensors

The measures of pressure and temperature are used directly or indirectly, and they constitute two very important components of any PL string.

Pressure is required when calculating PVT. It can be used as an indication of the production stability. It can supplement a missing/faulty density measurement when differentiated. It provides SIP with one of the key information.

Pressure gauges may be divided into Strain gauges or Quartz gauges. For strain gauges, the main measurement concept is mechanical distortion induced by the pressure applied. There are several sensor types based on Bourdon tubes, thin film resistors, sapphire crystals, etc.

In Quartz gauges, a quartz sensor oscillates at it's resonate frequency. This frequency is directly affected by the applied pressure.

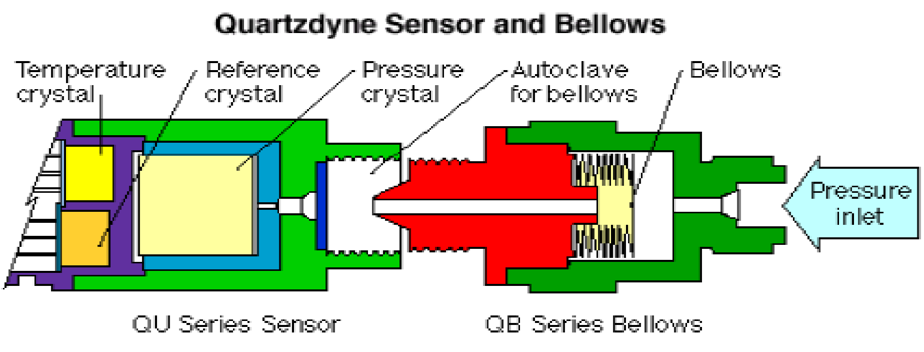

Figure 68: Quartz sensor example (***Courtesy:*** *Quartzdyne*).

The temperature is used in PVT calculations just like the pressure. This may also reveal flow outside the wellbore because of cement channeling leak for instance. The temperature can be used quantitatively, given the fact that there is an appropriate forward model for calculations.

The temperature sensor measures the temperature of the borehole. Sensor that responds extremely fast to changes in the temperature.

One of the first production logs were the Temperature logs and are still commonly relied on today to qualitatively (and sometimes quantitatively) yield a variety of information.

- One of the primary uses is for fluid entry identification from the change in temperature that normally occurs when fluids from different depths enters a well bore.
- Besides, temperature logs can additionally indicate flow behind casing or tubing, such as channeling of gas or liquids.

Other applications include Detection of Fluid Exit Points:

- Defining Cement Placement and Top
- Locating Gas Entries
- Defining the Lowest Point of Production or Injection
- Identification of Casing, Tubing, or Packer Leaks
- Checking Gas-Lift Valves
- Determining Hydraulic Frac Height
- Gradient, Locating Lost-circulation Zones
- Defining the Geothermal

Figure 69: Temperature sensor (***Courtesy:*** *Spartek*).

<u>Radioactive -Tracer Logging</u>

Radioactive tracer logging is one of the most popular logging methods used today to quantitatively test the injections profiles. Radioactive-tracer logging methods may be classified into two broad categories: (i) injection of a tracer material from the surface and (ii) ejection of a radioactive tracer from a logging tool in the well-bore. The first category includes such techniques as injecting radioactive proppant during a fracture treatment. Running a gamma ray detector after treatment gives some indication of the fracture location. Another application in the first category is tagging cement with a radioactive tracer. Again, a subsequent gamma-ray survey locates the tagged cement. (***Smolen 1996***). Because logs are usually self-explanatory in the first category and are discussed in detail elsewhere, we will focus on logs from the second category. These logs are generally run to evaluate injection profiles.

Obtaining injection profiles from radioactive-tracer logs is dependent on the tracer's ability which is miscible with the well-bore fluids, to disperse rapidly and then migrate the well-bore fluids. When the tracer moves with the well-bore fluid, monitoring the velocity or loss of tracer from the well-bore should mirror the distribution of velocity or fluid loss of the injected fluid. Therefore, because the gamma radiation emitted by the radioactive tracer can penetrate through casing and cement, a radioactive-tracer log can, in some instances, be used to monitor the channels behind casing, though other logs, such as temperature or noise logs, often identify channels more conclusively.

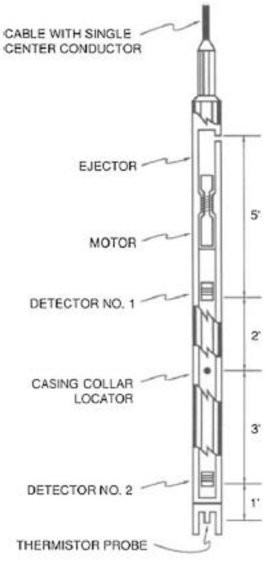

Figure 70: Radioactive-tracer logging tool (***Courtesy:*** *Spartek*).

Centralizing the logging tool is often a good practice in any radioactive-tracer logging, if the completion of the well is required. With the tool decentralized, tracer may be ejected against the casing wall, resulting in poor mixing of the tracer in the injection stream. Radioactive tracer tools are often run without centralizers because of the small tubing size, to allow more rapid tool movement, or simply for ease of operation.

Two types of radioactive-tracer logging methods-tracer-loss (timed-slug) and velocity shot are widely used today. In the tracer-loss process, a single slug of tracer material is expelled into the well-bore above all zones of fluid loss (***Smolen 1996***). The tracer concentration is then measured as a function of depth by passing a gamma ray detector repeatedly through the tracer as the tracer slug moves down the well-bore.

The tracer-loss method was developed for open-hole completions with irregular well-bore diameters. The velocity-shot approach is to calculate the transit time between two points of a tracer slug (usually between two gamma ray detectors, but often between the ejector and one gamma ray detector).

3.2.3 Tools for Completion Inspection

Tools for monitoring the mechanical status of the completion string include:

- Cement bond logs: (CBL, CET)
- Casing-collar logs: (CCL)
- Casing inspection logs: (ETT, PAL, calipers)
- Casing potential logs

In addition to these direct measurements of the status of the completion string, all the fluid typing, and monitoring tools may be used to infer completion problems. For example, a temperature log may indicate a tubing leak.

Depth and ID Devices

The depth is determined by measuring the length of the cable run in the hole. The depth measurement does not consider potential cable stretch or conversely slack due for instance to deviation or restrictions (***Liu 2017***). A tension measurement can be used to identify these situations. The log data has to be offset in time to be displayed at the same depth as stated earlier. This is because the various sensor measurement points are a different depth.

- Depth correction: Open Hole Gamma Ray. The tool ‘0’ is set at the surface when the log is run. The first task in the data QAQC is to set the log data consistently with the other available information: completion, perforations etc. This can be achieved by loading a reference Open-hole Gamma Ray and shifting the acquired data to that the Production Logging and Open -Hole curves overlay. The signal may not be strictly the same, due to completion, scale etc.

- Depth correction: Cased Hole CCL. An alternative to the Gamma Ray for depth correlation is a CCL measurement that will react in front of the Casing Collars, at known depths.
- ID calculation: Calipers. Calipers are mechanical devices used to calculate the cross-section of the wellbore. These are important because it is necessary to know the cross section to convert velocities to flowrates. Even in cased holes, a completion diagram may not reflect the reality. Calipers can be integrated into the spinner tool or as a separate device. They usually measure the diameter in two ways orthogonally. In this case they are referred to as X-Y calipers.

	Sphere of measurement		
Tool name	Formation properties	Fluid type of flow	Status of tubulars
Pulsed neutron	✓		
Gamma ray	✓		
GR Spectra	✓		
Inelastic gamma	✓		
Carbon/oxygen	✓		
Flowmeters		✓	✓
Temperature		✓	✓
Fluid density		✓	
Gradiomanometer		✓	
Radioactive tracers		✓	✓
Noise logs		✓	✓
Cement bond log			✓
Casing-collar locator			✓
Electromagnetic thickness tool			✓
Pipe – analysis log			✓
Calipers			✓

Table 11: Common PL devices (*Wilson, 2016*).

3.3 A typical Production Logging Job Sequence

In Production Logging, the basic assumption is that the well is in a continuous state. It is therefore necessary that the well be stabilized before running the tools. A typical job will consist of several surveys corresponding to various surface conditions. Shut-in surveys are often recorded with the goal being to calibrate the tools in an environment where the stages are separated. Shut-ins can also reveal crossflow due to differential depletions; they provide a reference gradient in shut-ins; they provide a baseline for a number of measurements in flowing conditions, e.g. Temperature.

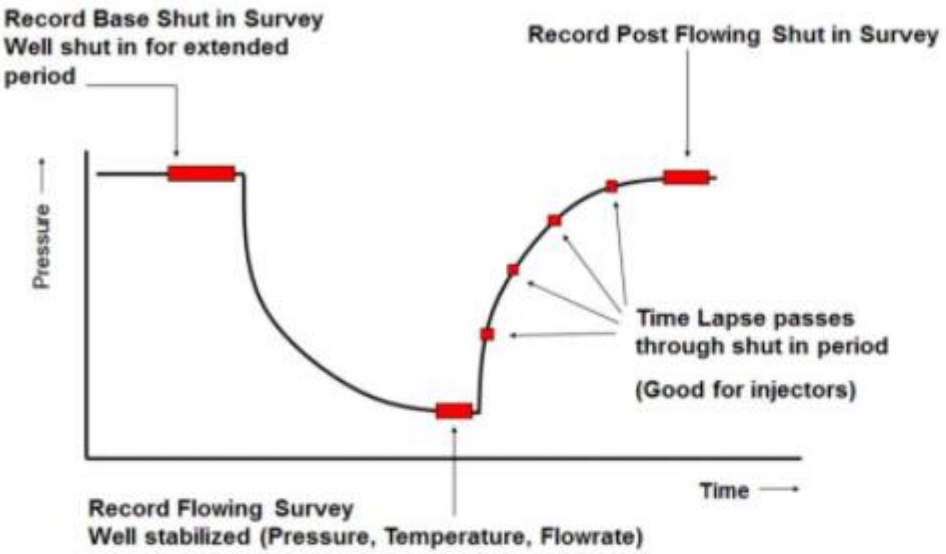

Figure 71: A typical PL job sequence (***Courtesy:*** *Schlumberger*).

Part of the job planning is to account for the time it takes to stabilize the well. The definition of stability is characterized as a pressure variation over time since we know from Well-test that the flowing pressure is generally not strictly constant. Time-lapsed passes will be interesting to document evolution with time, for instance, the warm-back following an injection cycle.

3.3.1 Planning a Production Logging Job

Planning is an integral part of a work production logging job. Such jobs can also only be carried out in safety during the daylight. Thus, the correct type of equipment must be available for the expected well conditions (*Liu 2017*). Before attempting any production logging job, the following checklist should be consulted:

- Full well-completion details
- Full production history
- All open-hole logs
- PVT data

Figure 72 shows the schematic of a typical production logging job. During a stabilized flow period (production, injection or shut-in) the production logging tool string, hanging on a cable controlled by a logging unit, is run up and down in front of the contributing zones at different speeds. There are also static transient surveys, referred to as 'stations', where the tool is immobilized at different depths. Using these runs the production logging interpretation engineer will calibrate the tools, then calculate a flow profile.

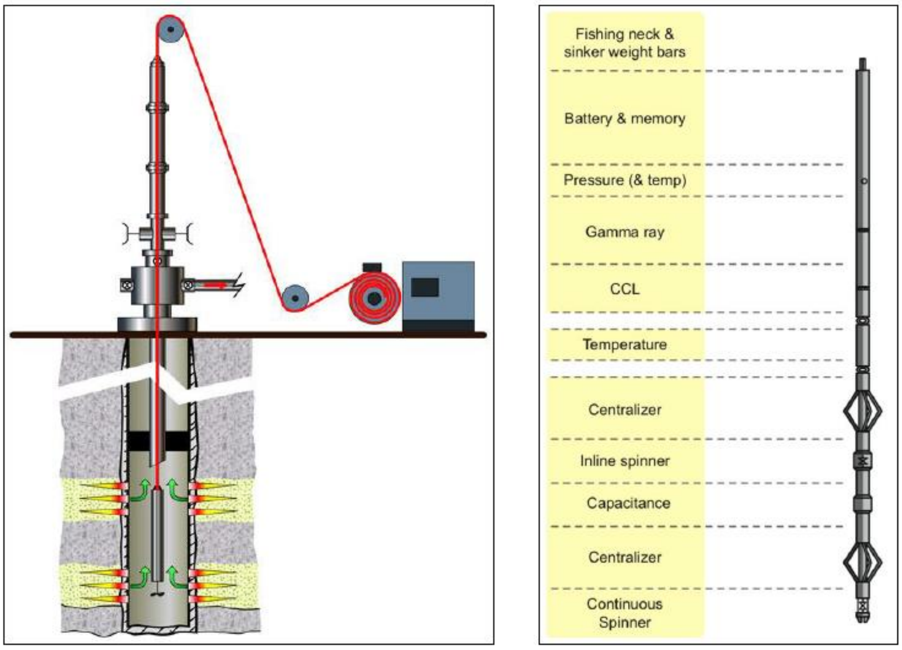

Figure 72: Schematics of Production Loggings operations and Production Logging tool string (*Courtesy: https://www.kappaeng.com*).

3.3.1.1 Pressure - Control Equipment

Practical details should not be forgotten. In particular, considerable care and attention should be given to the matter of working on a well that has pressure at the wellhead. It is a good idea to plan well in advance with the logging-service company using the following checklist:

- Wellhead connection
- Riser requirements
- Tubing restrictions (minimum ID)
- Tubing-head pressure
- Safety (H_2S/pressure/temperature ratings)

In general, when working against wellhead pressure the logging cable will be a single conductor armored cable about 1/4 in. in diameter. To seal the wellhead assembly against well fluids, a stuffing box or hydraulic packing gland will be used (*Etnyre 1989*). For high pressures, a "grease-seal" assembly will be used. To get logging tools into and out of the well safely and efficiently, a section of riser will be needed. A typical setup is illustrated in ***Figure 72***. Note that, above the wireline blowout preventer, this pressure-control assembly has (i) a tool trap, (ii) multiple sections of riser, and (iii) the pressure sealing equipment. When retrieving a tool from the well, it is sometimes difficult to gauge exactly where the cable head is in the riser.

If it is pulled up against the pressure sealing assembly too briskly, the tool may shear off the end of the cable and drop back into the well. To prevent this undesirable event, the tool trap catches the tool at the base of the riser.

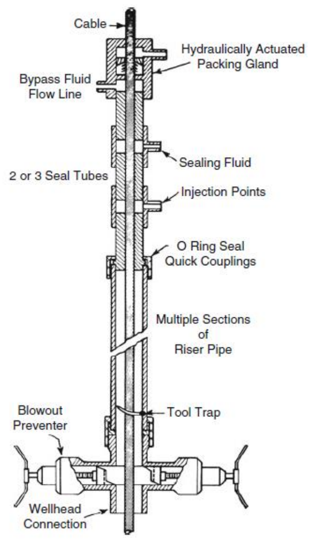

Figure 73: Production logging wellhead pressure – control assembly (*Courtesy: Schlumberger*).

The cable itself is at all times subject to an extrusion force, since the portion inside the riser experiences wellhead pressure, while the portion outside the riser experiences atmospheric pressure. The upward force is thus the difference in pressure multiplied by the cross-sectional area of the cable itself. Sometimes this upward force can be surprisingly large, and tools will not go down the well unless “ballasted” with additional weights.

Production logging is very much important to develop reservoir production modeling and processes. Therefore, it is important to understand the tools and techniques that are applied to the process. Production logging is also important for identifying production and completion anomalies and problems. A production log is usually run by the operator in a flowing wellbore. It helps to measure the zonal contribution of water or hydrocarbons to evaluate the flow performance model and stimulation effectiveness. Running production logs in horizontal wellbores presents unique challenges requiring modification not only to the tools but also in the delivery techniques. Unlike flow in a vertical well, in a horizontal well, wellbore production is different. Therefore, special sensors are required to properly measure the holdup across the lateral section.

4. FUTURE TRENDS ON WELL COMPLETION & PRODUCTION LOGGING

4. FUTURE TRENDS ON WELL COMPLETION & PRODUCTION LOGGING

4.1 Future tendencies in well completion

The future trend in well completion is dependent on the risk and unpredictable obstacles associated with the area's existing practices and technologies. Some of the examples in this regard are:

Horizontal completion challenges: Horizontally drilled long sections long sections through a single reservoir present a different set of challenges. Significant pressure drops occur in homogeneous formations, within the open-hole interval as fluids flow from total depth (TD) toward the heel of the well. This can result in significantly higher drawdown pressures at the heel than at the toe, which is known as the heel-toe effect (***Figure 74***). This difference induces uneven inflow along the well path and leads to water or gas coning at the heel. Water or gas breakthrough anywhere along the wellbore length may also arise from heterogeneity of the reservoir or from differences in distances between the wellbore and fluid contacts. Pressure variations within the reservoir caused by compartmentalization of the reservoir or by interference from production- and injection well flow can also lead to early breakthrough (***Hossain & Al.Mayed. 2015***). There are some challenges in horizontal well completions which are well integrity, long section exposed to different pressure regime, pressure drop across the section, annular flow, erosion from sand production, zone isolation and production selection, water production and early break though (heel-to-toe problems). The mechanical method is the simplest and fastest way. However, sometimes this does not work correctly, and some filled issues or geological issues complicate the installing of packers or the functioning of isolation wasting time and so on. Next is the option of chemical treatments, which also involve larger capital investment and more complication designs and execution factors.

The heel-toe effect in horizontal wells: Pressure losses along a horizontal wellbore in a homogeneous formation cause the flowing tubing pressure to be lower at the well's heel than at the toe. Oil from sections near the toe arrives at the wellbore. Water or gas is attracted to the heel resulting in an early end to the active well's life. Also, the completion of horizontal wells is influenced by well placement above the oil-water contact.

The completion scenarios for wells in horizontal placement depend on vertical permeability, fluid viscosity and pay zone thickness. All suggested solutions will decrease oil production or limit the flow or allow high-water production. As a result, the subsequent cost of separation will increase and the wasting or re-injection of pressure will decrease and deplete the reservoir, which leads to a loss of valuable reserves that could be produced.

Figure 74: Heel-toe effect (*Courtesy: Schlumberger*).

Well completion designs considerations: There are various well completion designs as is expected from the wide variety of operational areas and environments. Varieties of designs that exist reflect some of the factors such as well characteristics, geographical factors, operational design constraints, the number of producing zones etc. Based on completion prospects for the water controlling technique, selection of the proper methods to be used effectively requires a clear assessment of the targeted case. Many data need to be gathered and analyzed (for example: production history of the well) (*Hossain & Al.Mayed. 2015*).

Many questions need to be answered: does it have excessive water production, is this production intentionally or slowly increasing trends or abrupt changes? Also, what is the history of well completion? What obstacles exist in the well? What restrictions due to pay zone thickness and water oil contact distance? All these factors combined set the base for screening criteria of un-wanted water control method.

Problems about well completion have been widely studied and many researchers have been working in this area. Many tools were built to tackle certain problems such as well integrity, sand production and water production. Worldwide unwanted water production creates huge problems in oil fields. Calculations show that an average of three barrels of water is provided for each barrel of oil production. The typical practice in vertical wells is to cover the water zone and perforate above. Nevertheless, the well would be abandoned in the horizontal zone if the water oil contact reached the horizontal section. Most approaches are used to limit this stage by delaying water breakthrough. Horizontal wells increase the potential of oil-water contact movement due to the phenomena of the high velocity of flow near heels compared to toes.

However, still, challenges are remaining in the area. Horizontal wells increased dramatically during the last twenty years and almost replaced vertical wells. These have become very common practice with recent technology and advanced tools. As a consequence, you may need a strong justification in order to justify vertical drilling. Then technology began to move towards multilateral wells and extended reach drilling. No one can deny the advantages of horizontal wells and their contribution to oil production and increasing exploited reserves, but some geological and reservoir cases put horizontal wells in a great challenge.

There might be some challenging solutions toward the well completion problem. The following are some of them:

- Eliminate the use of ICD valves and use a dual lateral completion to control the flow speed at the heel of a horizontal well which helps to avoid erosion at that section of the well and early water break through. It can use a mesh screen in the open section of the lateral to simplify the completion while providing sand control.
- For a lengthy horizontal well instead of a conventional horizontal well with length L, use a dual multilateral well with length $\frac{L}{2}$ to avoid geo-steering problems and zones with different pressure.
- In the presence of a gas cap and in the production of oil reservoirs with a bottom aquifer the use of dual multilateral wells can be expanded and widely used to minimize conning and gasping capacity in oil pay output. Because they provide the same flow rates for larger reservoir exposure and drainage areas, they reduce drawdown on the formation.

4.2 Future perspectives in production loggings

The ongoing development effort in understanding three-phase flow is delivering results, including detailed gas holdup and velocity measurements, that are reshaping PL services. However, there is still an important flow domain not adequately covered by today's technology – environments where there is low water holdup and significant drain hole deviation. Work is under way at SCR to understand the complex fluid dynamics, flow instabilities and phase mixing in all regions. This experimentation together with hydrodynamic modeling will lead to better future understanding and management of flow in the borehole (*Baker et al. 2015*).

Improved instrumentation and tool technology are also promising faster, more efficient and lower-cost services, some using slickline. Other applications will see permanent downhole sensors used for production monitoring. These devices are rapidly becoming more sophisticated, measuring properties other than temperature and pressure such as hydrocarbons and phase mixing.

The outlook for production logging is certainly brighter now that it has been at any time during the last decade. Operators can look forward not only to a better understanding of their reservoirs, but also to the use of this knowledge for more effectively managing their assets.

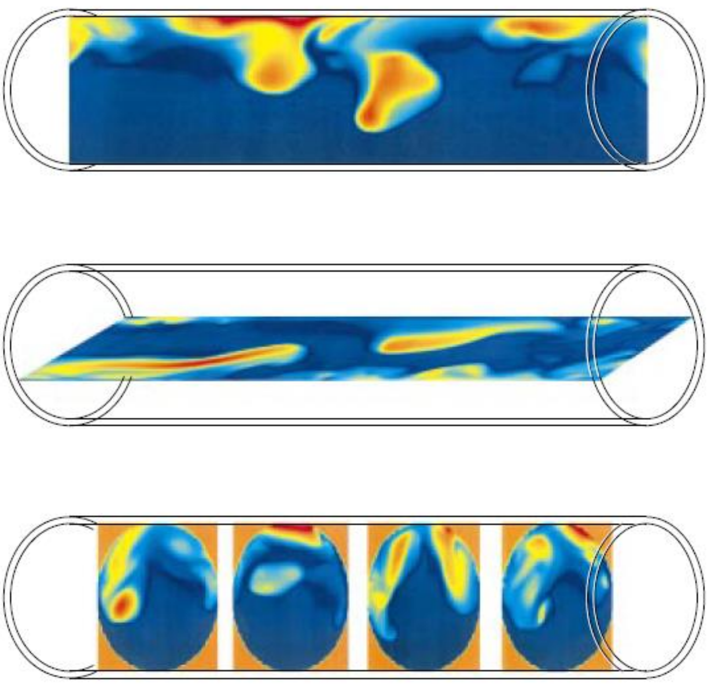

Figure 75: Computed 3D droplet-averaged simulations of two-phase flow showing the effects of shear instabilities. Mapped projections of fluid holdup are shown for horizontal (top) and vertical (middle) lateral cross section of the borehole and at four positions cutting vertically across a borehole (bottom). Oil (red) rises due to buoyancy forming an emulsified layer of oil on

the high side of the pipe. The lighter, upper layer flows at a higher velocity than does the water (blue). This shear flow becomes unstable and an instability occurs that causes the emulsion of oil to disperse in the water. Large eddies mix the two phases up. Then the process repeats farther up the pipe. Such fluid simulations help scientists test fluid-flow models under many conditions and design better methods to measure their properties (***Courtesy: Baker et al.1995***).

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