Introduction 1

CONTENTS

LEARNING OBJECTIVES:

Having worked through this chapter the Student will be able to:

- Discuss and value the integrated nature of production technology and the contribution of each of the technology subsites.

- Understand the total economic impact of production technology to capital investment planning and operating cost budgeting.

- Define the content and scope of production technology terminology.

- Discuss the concept of a production system and understand the long term dynamics of reservoir production and the evidence in terms of further production characteristics and performance.

- Discuss and define concepts of inflow performance, lift performance and the integrated nature of the full capacity of the reservoir well system.

- Explain the interaction, in terms of well life cycle economics, between capital investment and operating expenditure requirements.

INTRODUCTION TO PRODUCTION TECHNOLOGY

The role of the Production Technologist is extremely broad. Currently within the operating companies in the petroleum industry, the role and responsibility does vary between companies but can be broadly said to be responsible for the ***production system.***

1. SCOPE

The ***production system*** is a composite term describing the entire production process and includes the following principal components:-

(1) The reservoir - it productive capacity and dynamic production characteristics over the envisaged life of the development.

(2) The wellbore - the production interval, the sump and the fluids in the wellbore

(3) Production Conduit - comprising the tubing and the tubing components

(4) Wellhead, Xmas Tree and Flow Lines

(5) Treatment Facilities

These are shown in figure 1

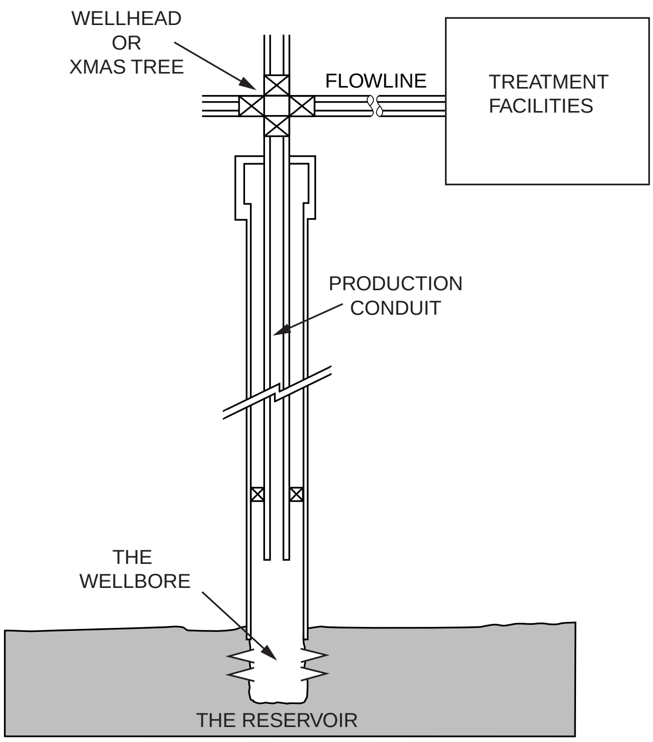


Figure 1
Elements of the production technology system

From the above definition it can be seen that the responsibilities of Production Technology cover primarily subsurface aspects of the system but they can also extend to some of the surface facilities and treatment capabilities, depending on the operating company.

The role of the Production Technologist is one of achieving optimum performance from the production system and to achieve this the technologist must understand fully the chemical and physical characteristics of the fluids which are to be produced and also the engineering systems which will be utilised to control the efficient and safe production/injection of fluids. The importance of the production chemistry input has only recently been widely acknowledged. It is clear that the physico-chemical processes which take place in the production of fluids can have a tremendous impact on project economics and on both the production capacity and safety of the well. The main disciplines which are involved in Production Technology are:

(1) Production Engineering:

Fluid flow
Reservoir dynamics
Equipment design, installation, operation and fault diagnosis

(2) Production Chemistry:

The Fluids	- produced, injected and treatment fluids
The Rock	- mineralogy, physical/chemical properties and rock strength and response to fluid flow.

2. CONTRIBUTION TO OIL COMPANY OPERATIONS

Production technology contributes substantially as one of the major technical functions within an operating company and in particular, to its economic performance and cashflow. As with any commercial venture, the overall incentive will be to maximise profitability and it is in this context that the operations for which the production technologist is responsible, are at the sharp end of project economics. The objectives of an oil company operation could be broadly classified, with respect to two complimentary business drivers, namely (a) maximising the magnitude of and accelerating cash flow and (b) cost minimisation in terms of cost/bbl-ie. total cost minimisation may not be recommended.

(1) Cashflow

The overall objectives would ideally be to maximise both cashflow and recoverable reserves. This would normally require maintaining the well in an operational state to achieve

(a) maximum production rates
(b) maximum economic longevity
(c) minimum down time

This is shown in figure 2

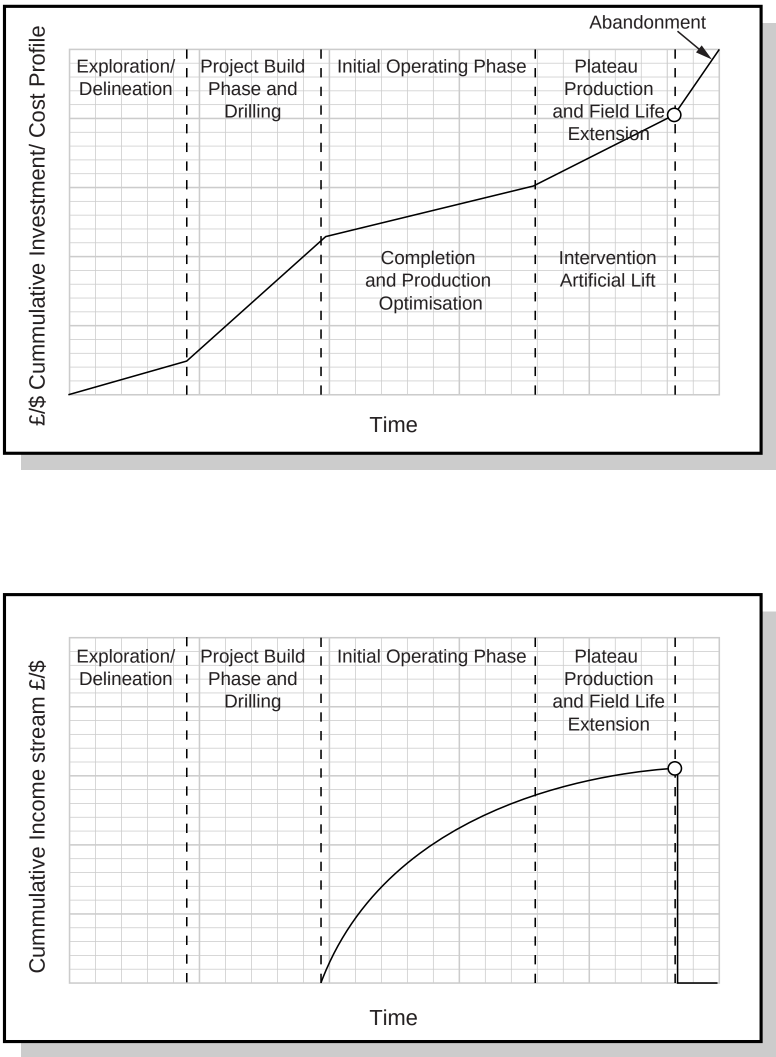


Figure 2
Economic phases of field development and input from production technology

(2) Costs

In this category there would be both fixed and direct costs, the fixed costs being those associated by conducting the operation and the direct or variable costs being associated with the level of production and the nature of the operating problems. The latter costs are therefore defined in terms of cost per barrel of oil produced. On this basis the production technologist would seek to:

(i) Minimise capital costs
(ii) Minimise production costs
(iii) Minimise treatment costs
(iv) Minimise workover costs

From the above, the bulk of the operations for which the production technologist is responsible or has major inputs to, are at the sharp end of ensuring that the company's operations are safe, efficient and profitable.

3. TIME SCALE OF INVOLVEMENT

The trend within operating companies currently is to assign specialist task teams to individual fields or groups of wells i.e. field groups or asset teams. In addition there are specialist groups or individuals who provide specific technical expertise. This ensures that there is a forward looking and continuous development perspective to field and well developments.

The production technologist is involved in the initial well design and will have interests in the drilling operation from the time that the reservoir is penetrated. In addition his inputs will last throughout the production life of the well, to its ultimate abandonment. Thus the production technologist will contribute to company operations on a well from initial planning to abandonment. The inputs in chronological order to the development and the operation of the well are listed below:

PHASE	NATURE OF INPUT/ACTIVITY
Drilling	Casing string design Drilling fluid Selection
Completion	Design/installation of completion string
Production	Monitoring well and completion performance
Workover/Recompletion	Diagnosis/recommendation/ installation of new or improved production systems
Abandonment	Identify candidates and procedures

4. KEY SUBJECT AREAS IN PRODUCTION TECHNOLOGY

Production technology is both a diverse and complex area. With the on-going development of the Petroleum Industry the scope of the technological activities continues to expand and as always increases in depth and complexity. It is however, possible to identify several key subject areas within Production Technology namely:-

1) Well Productivity
2) Well Completion
3) Well Stimulation
4) Associated Production Problems
5) Remedial and Workover Techniques
6) Artificial Lift / Productivity Enhancement
7) Surface Processing

These constitute the facets of Production Technology as shown in Fig 3.

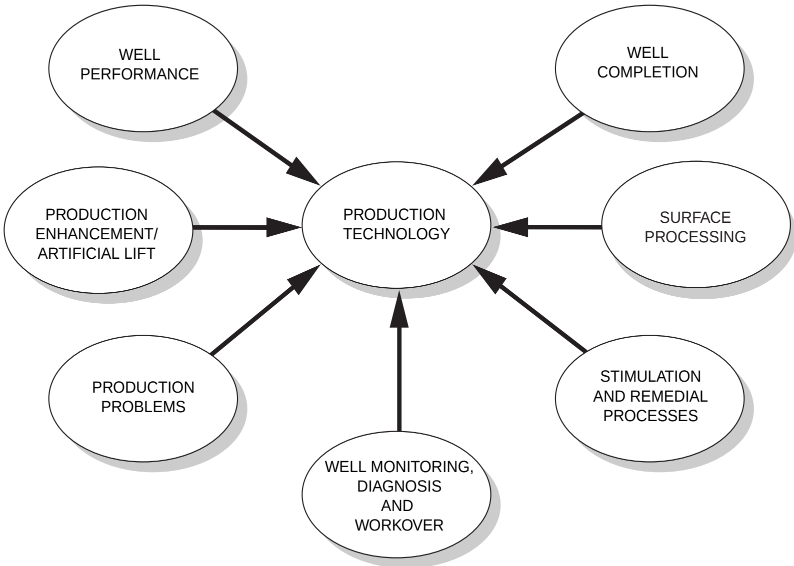


Figure 3 Production Technology Topics

Consider each of these in turn.

4.1 Well Productivity

An oil or gas reservoir contains highly compressible hydrocarbon fluids at an elevated pressure and temperature and as such, the fluid stores up within itself considerable energy of compression. The efficient production of fluids from a reservoir requires the effective dissipation of this energy through the production system. Optimum utilisation of this energy is an essential part of a successful completion design and ultimately of field development economics. Where necessary and economic, this lift process can be supported by artificial lift using pumps or gas lift.

The productivity of the system is dependent on the pressure loss which occurs in several areas of the flow system namely:-

- The reservoir
- The wellbore
- The tubing string
- The choke
- The flow line
- The separator

These are shown in figure 4. Under natural flowing conditions the reservoir pressure must provide all the energy to operate the system i.e. all the pressure drop in the system.

$$P_R = \Delta P_{SYSTEM} + P_{SEP}$$

where;
P_R = reservoir pressure
ΔP_{SYSTEM} = total system pressure drop
P_{SEP} = separator pressure

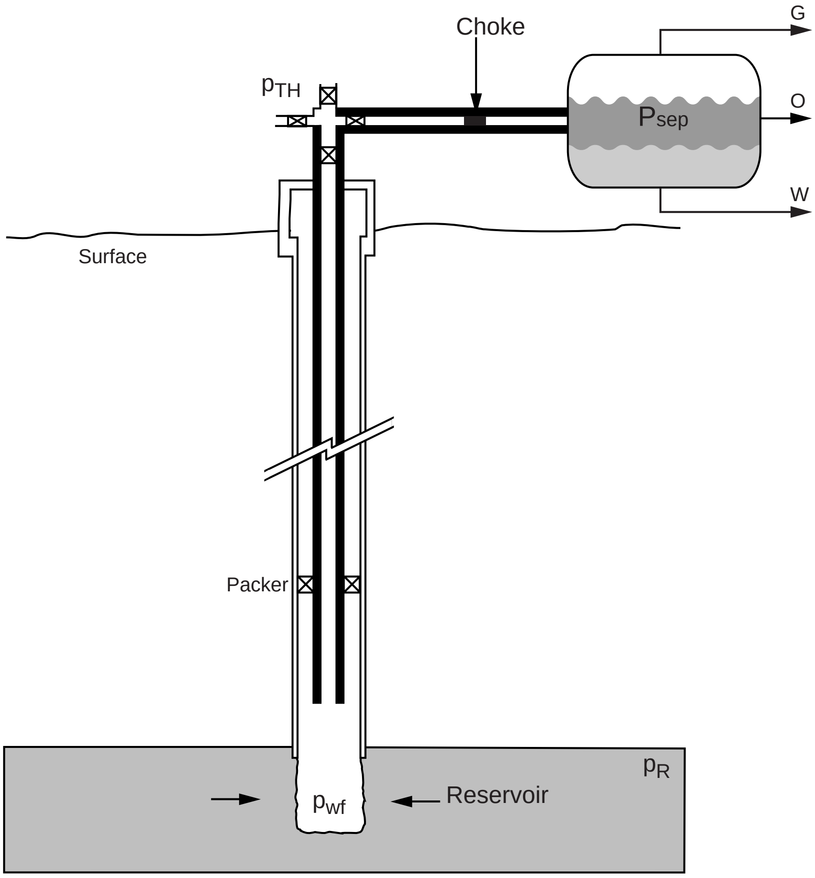


Figure 4
The Production System

The optimum distribution of energy between these various areas has a major bearing on the cost effectiveness of a well design and hence production costs.

The pressure drop which occurs across the reservoir, ΔP_{RES} and is defined as the ***inflow performance relationship*** or ***IPR***. The pressure drop and causes floe is in the tubing and wellbore ΔP_{TBG} is that which occurs in lifting the fluids from the reservoir to the surface and it is known as the ***vertical lift performance*** or ***VLP***, or ***the tubing performance relationship*** or ***TPR***,

i.e. for natural flow $R = \Delta P_{RES} + \Delta P_{TBG} + P_{TH}$

Where;
P_{TH} = Tubing head pressure

The pressure drop across the reservoir, the tubing and choke are rate dependant and these relationships therefore define the means by which we can optimise the production of the fluid from the reservoir.

In some cases there will be significant limitations on the extent to which we can optimise the dissipation of this energy. These are the following:-

(1) ***Limited Reservoir Pressure*** **-** in cases where the reservoir pressure is limited, it may not be feasible to achieve a significant and economic production rate from the well. In such cases it may be necessary to either assist in maintaining reservoir pressure or arrest the production decline by the use of gas or water injection for pressure maintenance or possibly system re-pressurisation. Alternatively, the use of some artificial lift technique to offset some of the vertical lift pressure requirements, allowing greater drawdown to be applied across the reservoir and thus increase the production capacity of the system, may be implemented

(2) ***Minimum Surface Pressure*** **-** on arrival at the surface, the hydrocarbon fluids are fed down a pipe line through a choke and subsequently into a processing system whereby the fluids will be separated, treated and measured. To be able to allow the fluids to be driven through this separation process and infact to provide some of the energy required for the process itself, it will be necessary to have a minimum surface pressure which will be based upon the required operating pressure for the separator. The level of separator operating pressure will depend upon the physical difficulty in separating the phases. In many cases the mixture will be "flashed" through a series of sequential separators.

4.2 Well Completion

Historically the major proportion of production technology activities have been concerned with the engineering and installation of the down hole completion equipment. The completion string is a critical component of the production system and to be effective it must be efficiently designed, installed and maintained. Increasingly, with moves to higher reservoir pressures and more hostile development areas, the actual capital costs of the completion string has become a significant proportion of the total well cost and thus worthy of greater technical consideration and optimisation. The completion process can be split into several key areas which require to be defined including:-

(1) The fluids which will be used to fill the wellbore during the completion process must be identified, and this requires that the function of the fluid and the required properties be specified.

(2) The completion must consider and specify how the fluids will enter the wellbore from the formation i.e., whether infact the well will be open or whether a casing string will be run which will need to be subsequently perforated to allow a limited number of entry points for fluid to flow from the reservoir into the wellbore.

(3) The design of the completion string itself must provide the required containment capability to allow fluids to flow safely to the surface with minimal loss in pressure. In addition however, it would be crucial that the string be able to perform several other functions which may be related to safety, control, monitoring, etc. In many cases the completion must provide the capacity for reservoir management. The completion string must consider what contingencies are available in the event of changing fluid production characteristics and how minor servicing operations could be conducted for example, replacement of valves etc.

4.3 Well Stimulation

The productivity of a well naturally arises from the compressed state of the fluids, their mobility and the flow properties of the rock, primarily in terms of permeability. In some cases reservoirs may contain substantial reserves of hydrocarbons but the degree of inter-connection of the pore space and the ease with which the fluids can flow through the rock, may be very poor. In such situations it may be beneficial to stimulate the production capacity of the well. Stimulation techniques are intended to:-

(1) Improve the degree of inter-connection between the pore space, particularly for low permeability or vugular rocks

(2) Remove or bypass impediments to flow, e.g.. damage.

(3) Provide a large conductive hydraulic channel which will allow the wellbore to communicate with a larger area of the reservoir.

In general, there are four principal techniques applied, namely:-

(1) ***Propped Hydraulic Fracturing*** - whereby fluids are injected at a high rate and at a pressure which exceeds the formation break down gradient of the formation. The rock will then fail mechanically producing a “crack”. To prevent closure or healing of the fracture, it is propped open by a granular material. This technique increases the effective well bore radius of the well.

(2) ***Matrix Acidisation*** - this process is conducted at pressures below the formation break down gradient and requires the injection of acid into the reservoir to either dissolve the rock matrix and/or dissolve damage material contaminants which has invaded the rock pore space. The main objective of acidisation is to increase the conductivity of the rock.

(3) ***Acid Fracturing*** - whereby acid injected at a pressure above the formation breakdown gradient, creates a fracture. The acid then etches flow channels on the surface of the fracture which on closure will provide deep conductive flow channels.

(4) ***Frac Packing*** - which is a shallow penetrating hydraulic fracture propagated usually into a formation of moderate to high permeability, and is subsequently propped open prior to closure. The process is used to reduce the near wellbore flow induced stress, and in some cases can also limit/reduce sand production

A number of other chemical treatments are available for specific situations.

4.4 Associated Production Problems

The on going process of producing hydrocarbons from a well is a dynamic process and this is often evidenced in terms of changes in the rock or fluid production characteristics. Problems are frequently encountered as a results of:-

(1) ***Physico-chemical changes*** of the produced fluids as they experience a temperature and pressure reduction as a result of flow through the reservoir and up the wellbore. This can result in a deposition of heavy hydrocarbon materials such as asphaltenes and waxes.

(2) Incompatibility between reservoir fluids and those introduced into the wellbore which may result in formation damage, e. g., scale deposits or emulsions.

(3) The mechanical collapse or breakdown of the formation may give rise to the production of individual grains or "clumps" of formation sand with the produced fluids.

(4) In formations containing siliceous or clay fines, these may be produced with the hydrocarbons creating plugging in the reservoir and wellbore.

(5) Corrosion due to the inherent corrosive nature of some of the components contained in the hydrocarbon system, for example, hydrogen sulphide (H_2S), carbon dioxide (CO_2), etc. chloride ions in produced water and oxygen in injected water can also create corrosion

(6) Processing problems can be encountered such as radioactive scales, foams, heavy metals deposits, etc.

4.5 Remedial and Workover Techniques

The production technologist is responsible for monitoring and ensuring the ongoing safe operation of the well. As such the responsibilities include:-

The identification and resolution of problems that will occur with the production system. This area of work is critical to the on going viability of field developments and wells, and can be sub divided into a number of areas namely:-

(1) ***Identification of problems and their source -*** this is normally conducted on the basis of surface information which indicates changes in production character istics such as rate and pressures. In addition down hole investigations using ***production logging techniques and transient pressure surveys*** (flow tests) can also help to identify the location of problems and the reasons for the changes

(2) ***Plan the required corrective action -*** this requires considerable attention to detail and will necessitate:-

(a) Identifying the equipment, manpower and other capabilities required.

(b) Identification and assessment of the unknowns/uncertainties.

(c) Identification and evaluation of the key safety points and mile stones.

(3) The assessment of the probability of technical and economic success.

(4) To identify the required resources, skills and their supervision.

(5) The workover phase is the most dangerous in terms of well control and the potential for damage on existing production wells. Attention to detail and careful planning is essential.

4.6 Artificial Lift

As stated above, wells will produce under natural flow conditions when reservoir pressure will support sustainable flow by meeting the entire pressure loss requirements between the reservoir and separator. In cases where reservoir pressure is insufficient to lift fluid to surface or at an economic rate, it may be necessary to assist in the lift process by either:-

- Reducing flowing pressure gradients in the tubing e.g. reducing the hydrostatic head by injecting gas into the stream of produced fluids. This process is known as gaslift.

- Providing additional power using a pump, to provide the energy to provide part or all of the pressure loss which will occur in the tubing.

In the case of gas lift, the pressure gradients will be reduced because of the change in fluid composition in the tubing above the point of injection.

When pumps are used, apart from fluid recompression and the associated fluid properties, there is no change in fluid composition. There are many specific mechanisms for providing pump power and the lift mechanism. e.g.

- Electrical powered centrifugal pumps

- Hydraulic powered centrifugal/turbine, jet and reciprocating pumps

- Sucker rod and screw pumps

Each artificial lift system has a preferred operating and economic envelope influenced by factors such as fluid gravity, G.O.R., production rate as well as development factors such as well type, location and availability of power.

4.7 Surface Processing

In some cases surface processing falls within the domain of production technology but in other cases it is the responsibility of a separate production department. The objectives of surface processing are as follows:-

(1) To effectively separate oil, gas, water and remove other produced materials such as sand.

(2) To monitor and adjust the chemical properties prior to separation/transport/reinjection for example:-

Deaeration
Defoaming
Filtration
Scale Inhibition

(3) To dispose of the oil and gas via pipeline or to storage this will necessitate equipment for pumping, compression, water removal, hydrate suppression and pour point depression.

(4) To prepare for and to reinject necessary fluids such as gas and water.

5. REVIEW

Production Technology is a diverse and broad based discipline, closely associated with the maintenance, operation and management of wells. It is critically important to the economic success of field developments.

As a discipline it interfaces with drilling, geoscience, reservoir engineers, as well as well intervention specialists. It is a business driven responsibility but is based on an integrated understanding of reservoir behaviour and engineering systems.

Reservoir Production Concepts 2

C O N T E N T S

LEARNING OBJECTIVES:

Havinng worked through this chapter the Student will be able to:

- Explain the importance of drive mechanisms and their importance to long term well performance and completion design for reservoir management.

- Explain of the impact of fluid compresibility on the production profile.

- Define the components of the production system, their interaction and the optimisation of well performance.

- Appraise options and benefits of pressure maintenance achieved through fluid injection.

- Explain the principles of simple artificial lift methods such as gas lift and pumps.

INTRODUCTION

A reservoir rock will produce fluid into the wellbore as a consequence of the fluid in the pore space which exists at high pressure and the rock being in a state of compaction. Thus the reservoir as such contains an enormous amount of compressive energy stored within the compressible hydrocarbon fluid which can be utilised to allow fluid to be produced from the reservoir into a well. Under natural flowing conditions the pressure is also significant enough to allow fluid to be flowed to surface and finally into treatment facilities.

The response of the reservoir to the pressure depletion process which occurs on production , will be dynamic and the fluid remaining in the reservoir will change both in terms of its volume , flow properties and in some cases its composition. The manner in which the reservoir system responds to the depletion process will be naturally governed by the ***drive mechanism.*** The long term production capacity of the reservoir will be defined by the extent and rate of pressure depletion. The depletion effects can be offset to some extent by the injection of fluid back into the reservoir.

Once the reservoir delivers fluid to the wellbore, sufficient pressure energy needs to exist to lift the fluid to surface if the well is to operate under ***natural flow.*** In the event that insufficient energy exists to allow production to occur or to occur at an economic rate, the well may require assistance by the application of ***artificial lift*** to provide all or a portion of the vertical lift pressure losses**.**

1. RESERVOIR DEPLETION CONCEPTS

The basic concept regarding the production of fluid from a reservoir is that for fluid to be produced as a result of its high pressure, then the reservoir system will deplete and must therefore compensate for the loss of the produced fluid by one or more of the following mechanisms:

(1) Compaction of the reservoir rock matrix

(2) Expansion of the connate water

(3) Expansion of hydrocarbon phases present in the reservoir:

(a) If the reservoir is above the bubble point, then expansion of the oil in place.

(b) If the reservoir is below the bubble point then expansion of the co-existing oil and gas phases

(c) Expansion of any overlying gas cap.

(4) Expansion of an underlying aquifer.

In most cases, as oil is produced, the system cannot maintain its pressure and the overall pressure in the reservoir will decline.

The pressure stored in the reservoir in the form of compressed fluids and rock represents the significant natural energy available for the production of fluids and requires to be optimised to ensure maximum economic recovery.

The mechanism by which a reservoir produces fluid and compensates for the production is termed the **reservoir drive mechanism.**

1.1 Reservoir Drive Mechanisms

The reservoir drive mechanism refers to the method by which the reservoir provides the energy for fluid production. There are a number of drive mechanisms and a reservoir may be under the influence of one or more of these mechanisms simultaneously.

1.1.1. Solution Gas Drive

If a reservoir contains oil initially above its bubble point then, as production continues, the removal from the reservoir of the produced oil will be compensated for by an expansion of the oil left in place within the reservoir. This will by necessity lead to a reduction in pressure and eventually the pressure within the reservoir will drop below the bubble point. Gas will then come out of solution and any subsequent production of fluids will lead to an expansion of both the oil and gas phases within the reservoir (Figure 1).

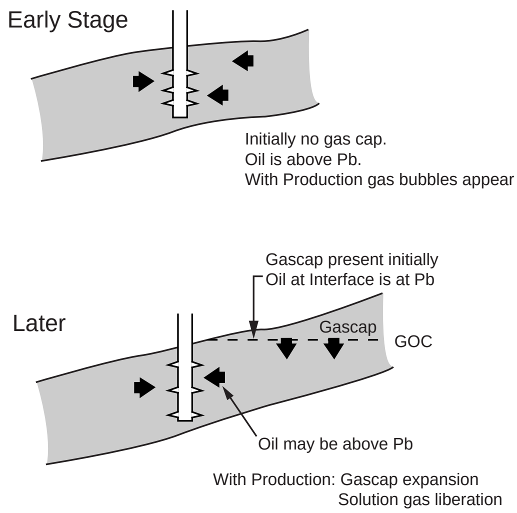


Figure 1
Solution gas drive reservoir in both the early and later stages of production

The gas will come out of solution as dispersed bubbles throughout the reservoir wherever the pressure is below the bubble point but will be concentrated in areas of low pressure such as the rear wellbore area around production wells. However, as discussed previously, the relative permeability to the gas will not be significant until the gas saturation within the pore space increases. Thus, until this happens, gas which has come out of solution will build up in the reservoir until its saturation allows it to produce more easily and this will be evident in a reduction in the volumetric ratio of gas to oil produced at surface, ie, the GOR in the short term. Eventually, as gas saturation increases, free gas will be produced in increasing quantities associated with the produced oil. Further the gas may migrate to above the top of the oil in the reservoir and form a free gas cap if the vertical permeability permits and sufficient time is allowed for gravity segregation. The produced GOR may be observed to decline at surface once the bubble point is reached due to the retention of gas in the pore space once liberated. The other effect will be a reduction in the oil production rate because as the gas comes out of solution from the oil, the viscosity and density of the oil phase increases and its formation volume factor decreases (ie, less shrinkage will occur with production). In addition, as the gas saturation in the pore space increases, the relative permeability to oil will decline. Later the observed production GOR will steadily increase due to increased gas saturation and mobility. Figure 2.

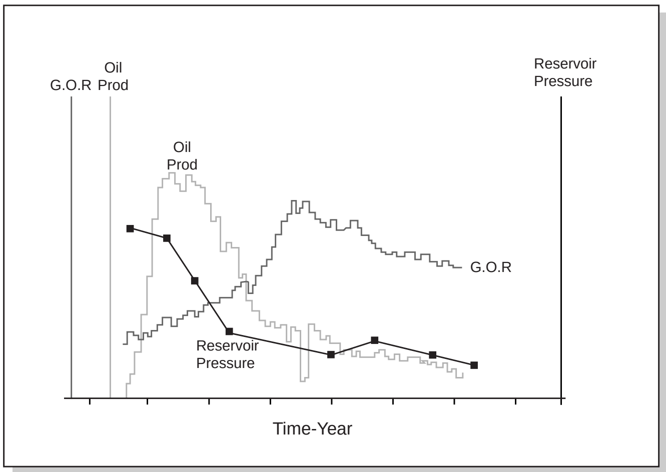


Figure 2 Performance of a solution gas drive reservoir

1.1.2 Gas-Cap Expansion Drive

Frequently, if reservoir pressure is initially equal to or at some later stage falls to the bubble point pressure for the oil, the gas released from solution may migrate upwards to form a gas cap on top of the oil. As previously discussed, the loss of the gas from being in solution within the oil, will lead to the oil having a higher viscosity and lower mobility.

With the solution gas drive mechanism, the production of fluids occurred primarily with gas expansion as it moved towards the wellbore. The performance of a gas cap drive reservoir in terms of the oil production rate and GOR will vary from that of a solution gas drive as shown in Figure 3. The pressure in the reservoir will in general decline more slowly, due to the capacity for expansion within the gas cap. The volume of the gas cap will depend upon:

(i) average reservoir pressure
(ii) bubble point pressure
(iii) GOR and gas composition

For such a reservoir, allowing reservoir pressure to drop should maximise the size of the gas cap and provide maximum expansion capability; however, it will also reduce oil mobility. Hence, there are two opposing effects. The ultimate performance of a gas cap drive reservoir is not only influenced by the above, but also by the operational capacity to control gas cusping into the well and thus retain its volume in the gas cap.

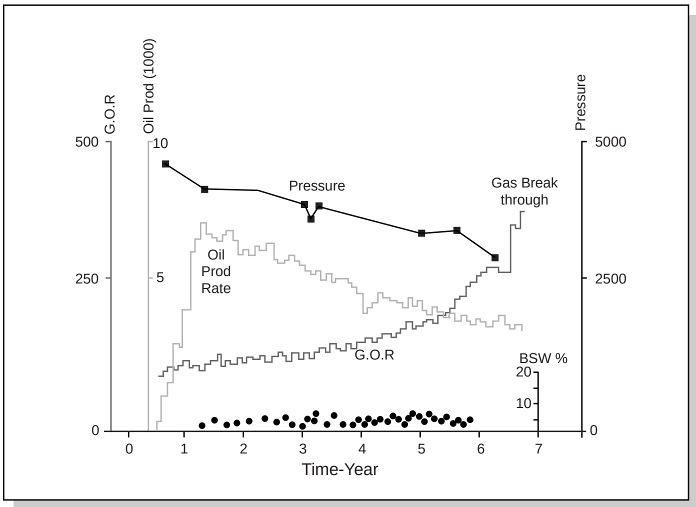


Figure 3
Performance of a gas cap drive reservoir-impact of substancial gas cap

1.1.3. Water Drive Reservoir

In a reservoir with a water drive mechanism for maintaining reservoir energy, the production of fluids from the reservoir unit is balanced by either aquifer expansion or, via injection of water into the reservoir. The water normally contained within an aquifer system can be defined as edge or bottom water drive depending upon the structural shape, dip angle and OWC within the reservoir (Figures 4/5). The net effect of water influx into the reservoir may be to prevent reservoir pressure dropping and, given the relatively low compressibility, for this to occur without depletion of the aquifer pressure, the aquifer volume must be very large. In the majority of cases, the aquifer is of a finite size and accordingly both the reservoir and aquifer pressure will decline in situations where the production rate is significant. If the production rate is small compared to the aquifer volume, then the compensating expansion of the aquifer may lead to no noticeable depletion for part of the production life of the field.

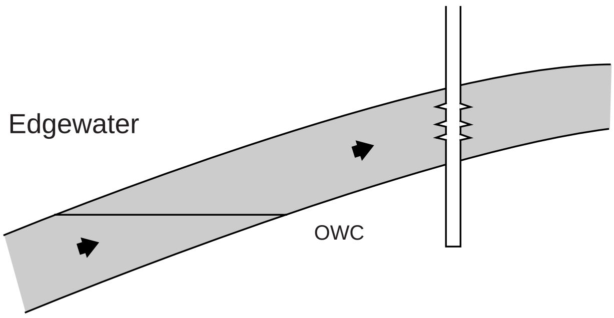


Figure 4
An edgewater drive reservoir

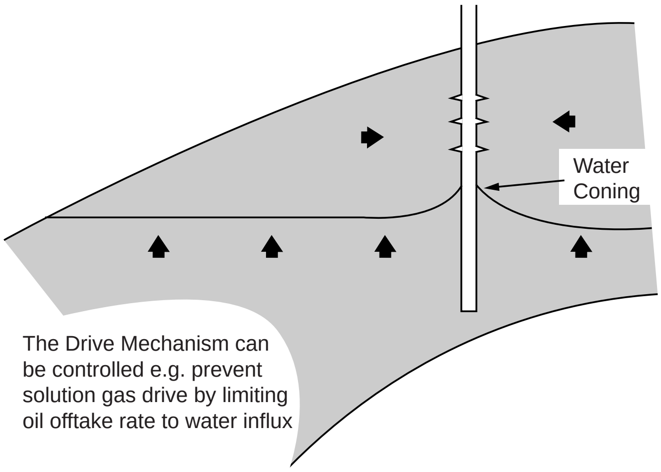


Figure 5
A bottom water drive reservoir

The expansion of the aquifer into the depleting oil zone in the reservoir will lead to a steady elevation in the oil water contact (OWC) and this may effect the zone within the reservoir from which production is required, e.g., the perforated section. In most cases, the rise in the OWC may not be uniform and, especially in the locality of a significant pressure drawdown, the water may rise above the average aquifer level towards the perforations. This phenomenon is referred to as coning. In addition, fingering due to heterogeneities may occur and this could lead to preferential movement through the more conductive layers and water accessing the wellbore prematurely.

Although water drive is frequently encountered as a naturally occurring drive mechanism, many fields, particularly in the North Sea, are artificially placed on water drive through water injection at an early stage in their development. This extends the period of production above the bubble point, maximise rates and improves recovery by immiscible displacement (Figure 6). Although water is less compressible than oil or gas and hence less able to provide the expansion volume required in the reservoir to compensate for the removal of fluid by production, it offers advantages in terms of ease of reinjection, safety, availability and safer handling compared to gas as well as powerful economic arguments.

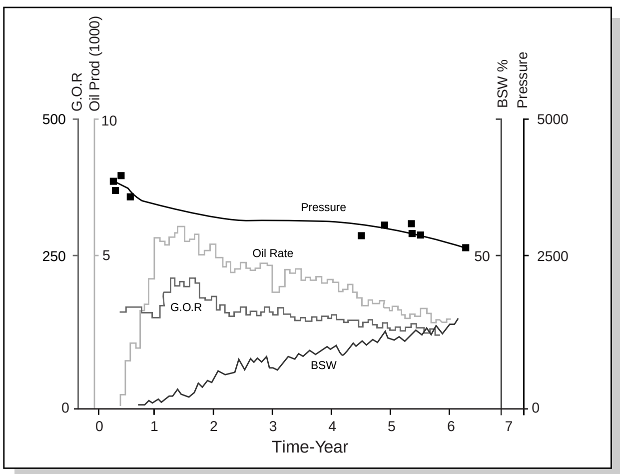


Figure 6
Performance of a well with water drive

1.1.4. Gravity Drive

Efficient gravity drive within a reservoir, although being an ideal recovery mechanism, is less common. In gravity drive, the hydrostatic pressure due to the oil column and pressure of the gas cap provides the drive downdip to a producing well system (Figure7).In addition the stable upwards expansion of the underlying aquifer supports the oil rim compression although in many cases the aquifer is small or non existent. For such a system to be effective requires maximum structural dip, low oil viscosity, good vertical and horizontal permeability, preferably an active gas cap and negligible aquifer activity.

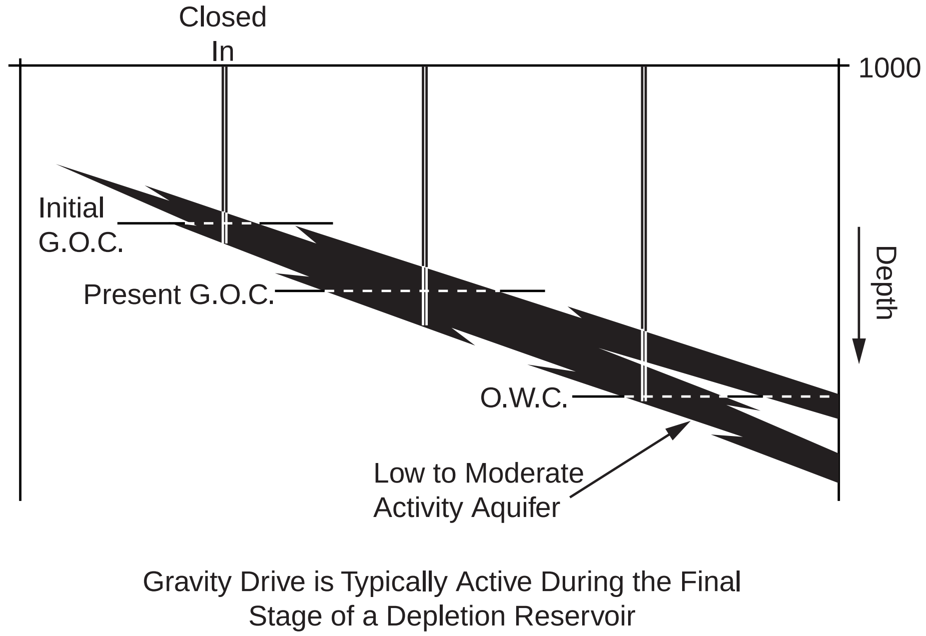


Figure7

The gravity drive process

1.1.5. Compaction Drive

The oil within the reservoir pore space is compressed by the weight of overlying sediments and the pressure of the fluids they contain. If fluid is withdrawn from the reservoir, then it is possible that the pressure depletion in the pore space attributable to the production of fluid can be compensated for by the overlying sediments compacting lower sediments such as those of the reservoir production zone. The impact of this is to create a reduction in porosity and thus a potential compression effect.

Such a mechanism known as compaction drive will cause a compensating compression of the fluid in the reservoir pore system. Compaction probably occurs to some limited extent in many reservoirs but the compactional movement of the land surface or seabed is rarely measurable except in certain cases (Figure 8).

1.1.6. Combination Drive

In the majority of reservoirs the production of fluids is not controlled by one but often by several drive mechanisms in combination. In such situations the response of the reservoir to production is less predictable.

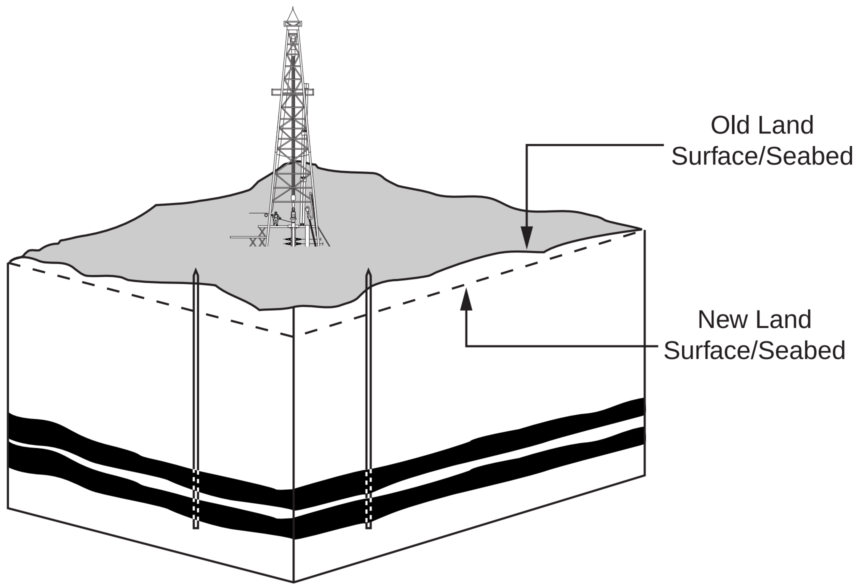


Figure 8
The compaction drive process

1.2 Reservoir Depletion or Material Balance Concepts

A reservoir can be viewed in volumetric terms, as a container in which multiple phases co-exist i.e. liquids, gas and solids. From the discussions on reservoir drive mechanisms, it is clear that for a reservoir of known volume, specific fluid phases and reservoir physical conditions, it should be possible to equate the production of fluids from the reservoir to the increase in volume of specific phases, due to inflow or expansion for each of the prevailing reservoir drive mechanisms and any gross changes in pore pressure. This volumetric "accounting" technique is referred to as material balance.

1.2.1. General concepts of material balance

Material balance is a technique which relates the movement into and removal of fluids from the reservoir to the amount of fluid contained within the reservoir.

The method relates cumulative fluid production to reservoir pressure and cumulative fluid produced, but does not generally define the period of production i.e. it utilises volumes not rates. The material balance utilizes the principle of conservation of mass, ie:

Mass of fluid originally in place = fluids produced + remaining reserves

The response of a reservoir to production is dynamic, ie, it is a function of time and, additionally, it is dependent on a number of changes, eg, as pressure declines in the reservoir unit as a result of fluid withdrawal, the following changes can take place:

(1) the pore volume of the reservoir rock will become smaller due to compaction
(2) existing connate water will expand
(3) oil, if undersaturated, will expand
(4) Oil if $P_{reservoir} \leq p_b$ will shrink as gas comes out of solution
(5) free gas, if present, will expand
(6) water may flow into the reservoir from an aquifer source;

The development of a material balance is the formulation of a zero-dimensional model which will relate the various volume changes of fluids within the reservoir and, because the volumes are pressure dependent, it means that the model will utilize pressure as a dependent variable.

Since the model is ***zero-dimensional,*** it utilizes properties and conditions assumed average for the reservoir unit; hence, the radial flow theory and its evaluation of $\bar{p}$ is of significance for material balance.

To improve the prediction of material balance, the model can be reformulated numerically as a 1-3 dimensional system and include time dependency, which is the basis of ***numerical reservoir simulation.***

One of the major applications of material balance studies is the prediction of the cumulative recovery of hydrocarbons from the reservoir unit.

$$\text{STOIIP} = N = V\,\phi\,\frac{(1 - S_{wc})}{B_{oi}} \qquad (1)$$

where STOIIP defines the total volume of oil inside the reservoir unit.

V =reservoir pore volume
ϕ = porosity
B_{oi} = FVF at initial reservoir conditions
S_{wc} = Connate water saturation

In particular, the amount of recoverable reserves is of more realistic interest since it defines total profit and cash flow. Hence:

Ultimate Recovery = STOIIP x RF

$$\text{Recoverable Reserves} = \left(V\,\phi\,\frac{(1 - S_{wc})}{B_{oi}}\right) RF \qquad (2)$$

The recovery factor, RF, is influenced by the technical method chosen for the recovery process, the application of which depends upon technical and non-technical constraints, such as:

(1) fiscal taxation regimes
(2) impact of political stability upon investments
(3) environmental/ecological factors
(4) predictability/complexity of technology

The efficient recovery of hydrocarbons requires the maximum utilization of the reservoir energy available, ie, primary recovery. However, consideration has to be given to supplementary recovery techniques (IOR), such as water and gas injection and equally important, the timing of such methods to provide the most efficient production of the total system.

An ideal production-injection scheme would maintain the volume of fluid in the reservoir and avoid any depletion in reservoir pressure (Figure 9). This will allow production rates to be maintained.

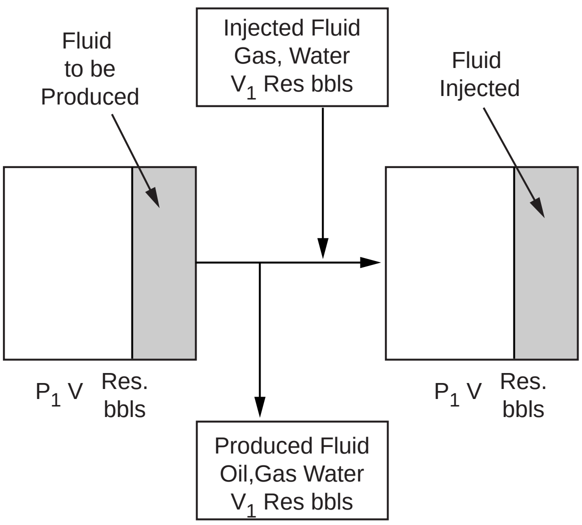


Figure 9
Ideal reservoir pressure maintenance: Balancing fluid injection and withdrawl

Because efficient primary recovery is so important, material balance studies must be highly dependent upon the expansion capabilities of the in-situ fluids, ie, the compressibility of the fluids.

The isothermal coefficient of expansion for a fluid is defined as:-

$$C = \frac{1}{V} \left. \frac{\partial V}{\partial P} \right|_T \tag{3}$$

Redefining ∂V as an expansion dV, gives

$$dV = C \cdot V \cdot dp \tag{4}$$

Relating each fluid to its compressibility using Equation 4, ie:

$$dV_{tot} = \text{Production} = Co.Vo.\Delta p + Cw.Vw.\Delta p + Cg.Vg.\Delta p$$

$$= \Delta p\,(Co.Vo + Cw.Vw + Cg.Vg) \qquad (5)$$

Thus, for a multifluid system, the sum of the changes in volume of each fluid phase must equal the cumulative volume (measured at reservoir conditions) of fluid extracted from the reservoir (Figure 10).

$$\Delta V_{TOT} = \Delta V_O + \Delta V_g + \Delta V_w$$

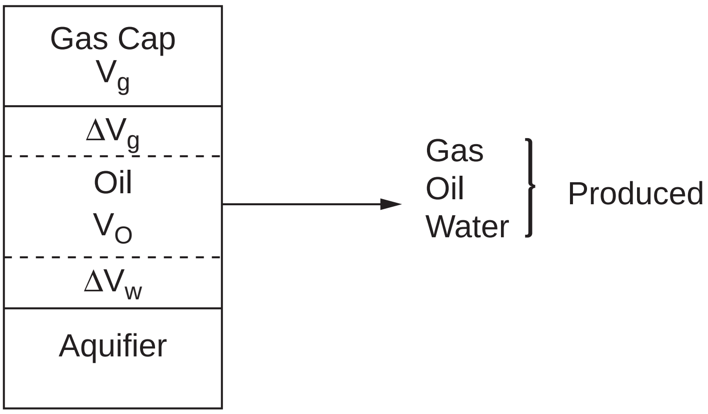


Figure 10
Fluid production by in situ expansion

Compressibility values for each phase are compositionally dependant but example values of compressibility at 2000 psia are:

C_o = 15 x 10^{-6}/psi
C_w = 8 x 10^{-6}/psi
C_g = 500 x 10^{-6}/psi

Therefore, dV_{tot} is highly dependent upon C_gV_g, ie, the quantity of gas cap gas, if present in the reservoir.

NOTE:
(1) The above ignores the contribution of the rock expansion.

(2) This reaffirms the benefits of fluid injection made in our earlier discussion of pressure maintenance

1.2.2. General form of material balance
For the basis of drawing a generalised form of the material balance for a reservoir the following balance will be assumed.

Original volume occupied by fluids	=	Present volume occupied by fluids	+	Contraction in pore space

Further, since a generalised form of the material balance equation is required, it will be assumed that the reservoir unit contains free gas, oil containing gas in solution, connate water and rock matrix. The concept of the generalised form of the material balance is shown in Figure 11.

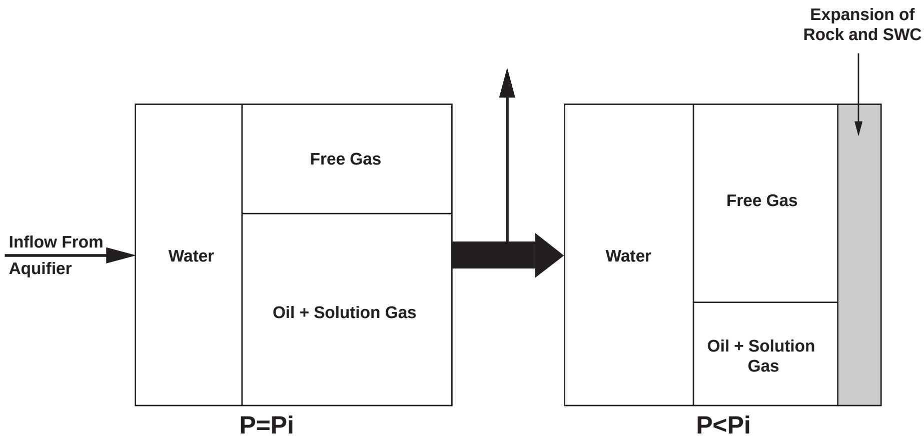


Figure11
Generalised form of material balance

During the decline in pressure from an original value of p_i to p, using the above volumetric relationship, a general form of the material balance can be devised as:-

Original Oil N . Boi	Original Oil N . Boi
||	||
Remaining Oil	(N - Np) Bo
+	+
Free Gas Remaining	[N Rsi - (N - Np) Rs - Gps]Bg
+	+
Change in gas cap volume	[(G - Gpc)Bg - G Bgi]
+	+
Net water influx	[We - Wp]Bw

(6)

Answer: The appropriate nomenclature is as follows:
N = stock tank oil originally in place
N_p = stock tank oil produced
R_{si} = initial solution gas oil ratio
G_{pc} = gas produced from gas cap
B_{gi} = initial gas formation volume factor
W_e = water encroached from aquifer
Gps = gas produced from solution

The above equation can be simplified depending upon the characteristics of the reservoir and the drive mechanisms.

(1) If reservoir pressure is above the bubble point then only solution gas will be produced, ie, $G_p = N_p . R_s$ and (b) G = 0.

(2) If no water influx occurs then $W_e = 0$ and if connate water is assumed immobile, then $W_p = 0$

(3) For most reservoirs the degree of pore volume contraction can be ignored.

Upon inspection of the material balance equation, it is apparent that:

(1) the equation does not feature any explicit time dependence.

(2) the pressure is only included explicitly in the term relating to water and rock compressibility. However, it must be remembered that the fluid formation volume factors are implicitly dependent upon pressure.

1.2.3. Application of Material Balance

(1) If we have production and pressure data, as well as volumetric estimates of the hydrocarbons initially in place, then we can calculate W_e.

(2) If $W_e = 0$ then the model is reduced to one using both pressure and production data.

(3) Given the volume of the gas cap and the reserves in place plus pressure and production data we can extrapolate to predict the response to variation (or decline) in average reservoir pressure. Such predictions are useful when linked to well performance calculations to identify:

(a) the need for artificial lift

(b) abandonment prediction

(a) Data Requirements

The accuracy of the material balance depends largely upon the accuracy of the data used.

PVT data B_o, R_s, Z

Production data	oil, gas, water, influx of water
Oil and gas initially in place N, size of gas zone m, f, S_{we}	- from petrophysics
Compressibility data	- water and rock
Relative permeability data	K_g/k_o, K_w/k_o vs S_o
Reservoir pressures	- well tests
Water influx	- W_e

The appropriate nomenclature is as follows:
R_s = solution gas oil ratio
Z = z factor (gas deviation factor)
K_g = gas permeability
K_o = oil permeability
K_w = water permeability
S_o = oil permeability

(b) Limitations of the Material Balance Formulation
The material balance developed above does not include/allow for

(i) Fluid Injection

- this may lead to repressurisation of the system
- for water, the balance may not be drastically affected although care should be exercised in its application
- for gas injection the validity of the material balance (gas injection is considered to be - negative production) is very suspect since the gas may go into solution and further, may result in a pressure increase which could give rise to the gas cap going back into solution.

(ii) Compaction

While the balance does amount for rock expansion it does not account for resorting or compaction of the formation.

(iii) The predicted quantities in terms of reservoir characteristics are bulk values only - no information is obtained about profiles or fluid distribution.

(iv) The material balance will only predict reservoir and fluid characteristics, i.e. it will predict the condition of the reservoir after an assumed event e.g. cumulative production, but it will not say when the response will occur, ie, the balance predicts how much, not how fast.

(v) The material balance equation has at least two unknowns, eg, future values of N_p vs P.

2. THE COMPOSITE PRODUCTION SYSTEM

From the foregoing, it should be clear that the energy stored within the reservoir, as a consequence of the natural compression of the fluids, is available to cause fluids to flow from the reservoir to the wellbore and then to surface.

The design of a producing system which efficiently uses this available energy to maximise the production from the reservoir is fundamental to efficient well completion design.

2.1. The Producing System

2.1.1 General Description

In the production of oil from the reservoir to a storage tank, the oil has to flow through a variety of restrictions which will consume some of the energy stored within the compressed fluids and represented by their pressure and temperature. The combined system of the reservoir, the wellbore and the surface treatment facilities is generally referred to as the production system (Figure 12).

Firstly, the oil has to flow through the reservoir rock to reach the drainage location of individual wells and, in doing so, a loss in pressure will occur within the fluid. This ***reservoir pressure drop***, or, as it is sometimes called, the "***drawdown***", is principally dependent upon the reservoir rock and fluid characteristics.

At the junction between the reservoir and the individual wellbore, the fluid has to be able to leave the formation and enter the wellbore. A major completion decision has to be made as to the way in which fluid connectivity between formation and wellbore is to be provided. In some cases, where the drilled hole through the pay zone is used for production, the entire cyclindrical surface area of the borehole is available for fluid entry from the reservoir. In other cases, after drilling the hole through the pay zone, the hole is lined with a steel tube known as casing/liner and a cement sheath installed by cementing between the drilled hole and the outer diameter of the casing. Then since fluid connectivity will not exist, specific entry points for the reservoir fluid through the casing wall are provided by perforating. Again, the number, location and characteristics of these perforations will influence the fluid flow and the associated pressure loss. The pressure drop generated by the perforations and other near wellbore completion equipment is known as the bottomhole ***completion pressure drop.***

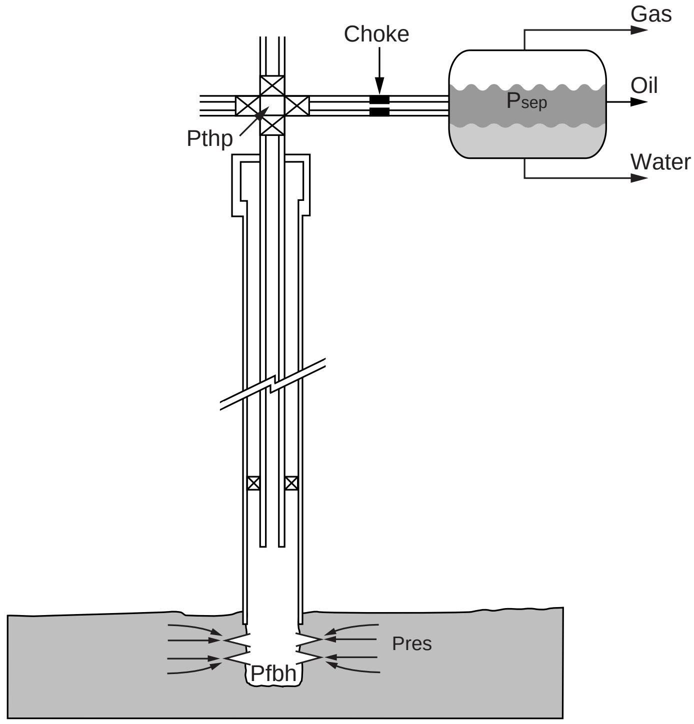


Figure 12
The composite production system

Once inside the wellbore, the fluid has to flow up the production tubing string passing through various sizes of tubing and through restrictions caused by other completion string components resulting in a loss in pressure of the fluid between the bottomhole location and surface. This pressure drop is the completion string or vertical lift ***pressure drop***. This pressure loss is attributable to 3 primary sources:

(1) ***frictional pressure loss***, ie, loss associated with viscous drag.

(2) ***hydrostatic head pressure loss*** due to the density of the fluid column in the production tubing.

(3) ***kinetic energy losses*** due to expansion and contraction in the fluid flow area and the associated acceleration/deceleration of the fluid as it flows through various restrictions.

The sum of these three pressure losses is termed the vertical lift pressure loss. It is possible to identify the pressure loss due to individual tubing components, such as downhole valves, to allow optimisation in terms of specific component selection.

When the fluid arrives at the surface, it passes through the surface equipment and flowline giving rise to additional pressure loss. The extent of these pressure losses will very much depend upon operating systems being minimal for platforms with small flowline lengths, but in some cases being significant for subsea wells or onshore wells distant from production manifolds or gathering stations.

The fluid then flows through a restriction known as a choke which is designed to cause a significant amount of pressure drop and, hence, provide stability to downstream separation and treatment operations over a wide range of reservoir conditions.

Downstream of the choke is a separator which is designed to separate out the liquid phases continuously to provide produced gas and oil for export and water for disposal.

Depending on the shrinkage of the oil, the volume of oil produced per reservoir volume of oil extracted will depend on the shrinkage of the oil. Figure 13.

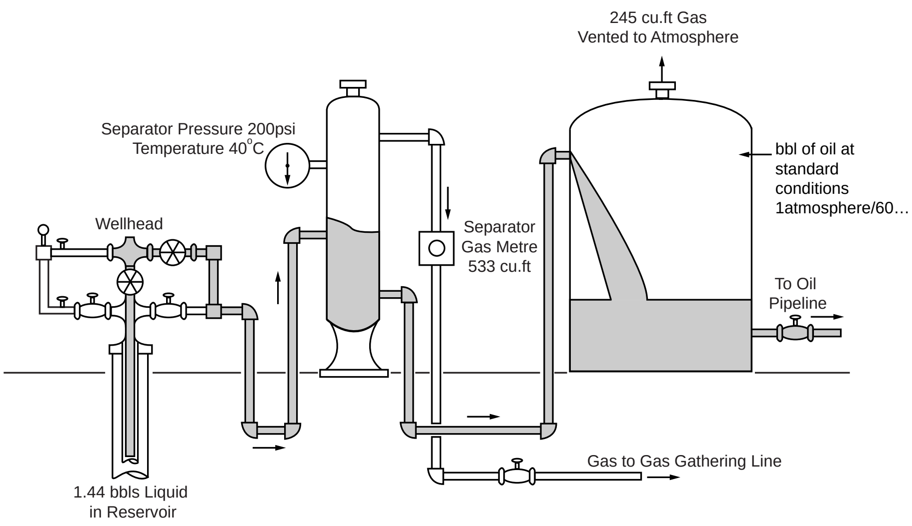


Figure 13
The flow system from wellbore to separator

2.1.2 Utilisation of Reservoir Pressure

In the development of a hydrocarbon reservoir, the energy stored up within the compressed state of the reservoir fluids has in the case of ***natural flow***, to provide the total pressure loss in the producing system. Based upon a fixed operating pressure for the separator, we can formulate the pressure loss distribution as follows:-

$$P_{RES} = \Delta P_{RES} + \Delta P_{BHC} + \Delta P_{VL} + \Delta P_{SURF} + \Delta P_{CHOKE} + P_{SEP} \quad (7)$$

where

P_{RES} is the initial or average pressure within that wellbore drainage area of the reservoir. (refer to Ch 3)

ΔP_{RES} is the pressure loss caused by the flow of fluid within the reservoir to the wellbore.

ΔP_{BHC} is the total pressure loss generated by the design of the fluid entry into the wellbore, ie, the bottom hole completion configuration.

ΔP_{VL} is the vertical lift pressure loss caused by fluid flowing up the production tubing string.

where

$$\Delta P_{VL} = \Delta P_{FRICT} + \Delta P_{HHD} + \Delta_{KE} \quad (8)$$

ΔP_{FRICT} is the frictional pressure drop

ΔP_{HHD} is the hydrostatic head pressure drop

ΔP_{KE} is the kinetic energy pressure drop

ΔP_{SURF} is the pressure loss generated in exiting the Xmas tree and surface flowlines.

ΔP_{CHOKE} is the pressure loss across the choke.

P_{SEP} is the required operating pressure for the separator.

Rearranging equation 7 to give

$$(P_{RES} - P_{SEP}) = \text{Available pressure drop for the system} = \Delta P_{TOT}$$

$$= \Delta P_{RES} + \Delta P_{BHC} + \Delta P_{VL} + \Delta P_{SURF} + \Delta P_{CHOKE} \quad (9)$$

All the pressure drop terms in equation 9 are rate dependent, hence

Total system pressure drop

$$\Delta P_{TOT} = [\Delta P_{RES} + \Delta P_{BHC} + \Delta P_{VL} + \Delta P_{SURF} + \Delta P_{CHOKE}]_Q \quad (10)$$

Thus, each of the pressure drops can be minimised either individually or collectively to produce a maximum attainable production rate for the available pressure drop. This is known as ***production system optimisation***.

It is essential to consider how each of these pressure drops can be minimised to provide a maximum potential production rate.

(i) To reduce the pressure loss due to flow in the reservoir, it is necessary to reduce the resistance to flow. This can be accomplished either by reducing the formation rock resistance, eg, increasing the permeability by acidisation or fracturing or by reducing the resistance to flow due to the fluid properties, eg, viscosity by utilising thermal recovery techniques. These alternatives may be costly, are not always applicable to all reservoirs and may involve considerable technical risk or uncertainty to be readily applied except in specific situations, eg, chalk reservoirs or very heavy crude oil reserves.

(ii) The pressure loss due to the bottom hole completion method has to be specified as part of the completion design and, as such, is a major area for production optimisation. It is likely that detailed consideration to some aspects in this area such as perforation shot density and length of perforated interval could be very beneficial in maximising the production capacity of the system.

(iii) Again, as with the bottom hole completion pressure loss, the vertical lift pressure loss is a major area for optimisation as not only does the engineer have to specify the length and diameter of all sections of the tubing string but also all the specific completion components such as nipples. Careful design in this area can provide significant optimisation of the productive capacity of the well.

(iv) For most situations the surface flowline pressure loss is relatively less important in that, although the in situ phase velocities will be higher than in the production tubing, it is considerably shorter in length. Exceptions include some subsea wells and onshore wells drilled on a wide spacing. However, minimising pressure loss here, by selecting an increased diameter pipeline and restricting the severity and number of directional changes can yield significant improvement in field productivity in some situations.

(v) Little flexibility exists to minimise choke size as it is required to give a specific pressure drop for a known flowrate to provide stability to the separator.

2.2. Supplementing Reservoir Energy

In section 2.1.2, the effective utilisation of reservoir energy was discussed with respect to production system optimisation. From equations (7) and (10), the production rate from a well is directly proportional to the average pressure in the reservoir pore volume drained by a well. To maintain rates and hence cash flow, it would be desirable to maintain reservoir pressure. From the earlier discussions on material balance, it can be seen that for this to occur either the reservoir would have to display no pressure depletion due to either:-

(i) Reservoir size being infinite

or

(ii) Volumetric replacement of produced fluids by either injection from an external source or movement from an adjacent fluid bearing portion of the reservoir, of gas, water or both fluids.

Clearly increased production rate could also be attained by either

(a) ***increasing the reservoir pressure***

or

(b) ***providing more energy for the vertical lift process***.

Increasing the reservoir pressure above its initial value is difficult to conceive for two reasons:

(1) In any reservoir development, to achieve any noticeable increase in reservoir pressure decline would require fluid to be injected into the reservoir over a considerable period of time and this would normally preclude any significant production taking place in view of the consequent depletion of the hydrocarbon volume and pressure which would be associated with it.

(2) The volume of fluid to be injected into the reservoir to provide an increase in pressure would be dependent upon the overall compressibility of the reservoir rock and fluid system. For reservoirs of commercial size, the volume of fluid would be considerable and accordingly uneconomic compared with the alternative methods available to increase fluid production.

The concept of supporting fluid production by assisting the vertical lift process is defined as ***artificial lift***. By this method the hydrostatic head pressure loss is either reduced by gas lift or the tubing pressure drop is offset by energy provided by a pump.

2.2.1 Fluid Injection into the Reservoir

The potential use of fluid injection to raise reservoir pressure above its initial level was largely discounted in the reasoning above. However, there are two aspects to the problem, the first being the absolute level of production rates achievable and, secondly, the duration for which these rates can be maintained and the schedule of declining production rates.

From the discussion of the material balance concept applied to hydrocarbon reservoirs, it is clear that unless fluid withdrawal from the reservoir can be compensated for by an equal volume of fluid flow into the reservoir from, say, a very large aquifer or another external source, then the reservoir pressure will fall. When the average pressure in the reservoir declines, then the available energy for production declines and as a result the oil production rate falls off.

Thus, the principal application of fluid injection into the reservoir is to try and balance the reservoir fluid volume withdrawn with that injected to thus maintain reservoir pressure. If this is accomplished, it will restrict the rate of production decline (Figure 14).

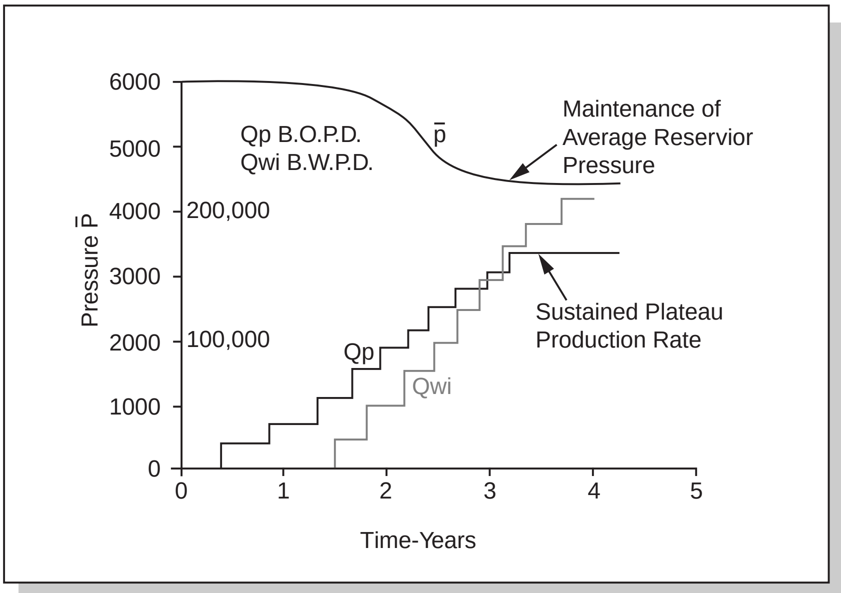


Figure 14
The benefits of fluid injection to sustain oil production

The decision as to whether water or gas should be injected is influenced by fluid availability and characteristics.

Water injection is of particular importance since water is usually available either as produced water or sea water in an offshore situation. It also requires minimal repressurisation and treatment. Water is, however, only slightly compressible and as such is not an ideal fluid for compression energy storage but, alternatively as compression costs are low it is normally possible to treat and inject relatively large volumes of water.

Gas, however, for **gas injection** is more compressible and hence more suitable to maintain reservoir pressure however it also requires considerable compression to allow its injection into the reservoir. The supply of gas would be a predominant factor and in most cases its commercial value is of primary importance and this might preclude its use for reinjection unless no means of export is available whereby flaring would be the alternative recourse. The alternative of deferring gas sales due to its injection would bear an economic cost.

2.2.2 Supplementing the Vertical Lift Process

There are several techniques which are available to assist in bringing oil to surface and these are collectively referred to as ***Artificial Lift Techniques.*** These processes are widely applied in all geographical areas. In some cases, they are essential to the initial economic development of a hydrocarbon reservoir whilst in other cases they are implemented later in the life of the field to maintain production at economic levels. The various techniques can be further classified into those which simply provide additional energy to assist the lift process and those which provide some reduction in the vertical lift pressure gradient.

(1) **Gas Lift**

The gas lift process involves the injection of gas normally into the annulus between the production tubing and casing. The gas is subsequently allowed to enter the flowstream within the production tubing at some specific depth through a single or more usually a series of gas lift valves (Figure 15). The injection of gas into the production tubing provides a stepwise increase in the gas liquid ratio of the fluids flowing in the tubing at that depth and throughout the tubing above the injection point. This results in a reduction of the bottomhole pressure and ***offloading*** of the well. To be able to enter the tubing, the pressure of the gas in the annulus, at the valve which will permit its flow into the tubing, must be greater than the pressure of the fluids in the tubing at that same depth.

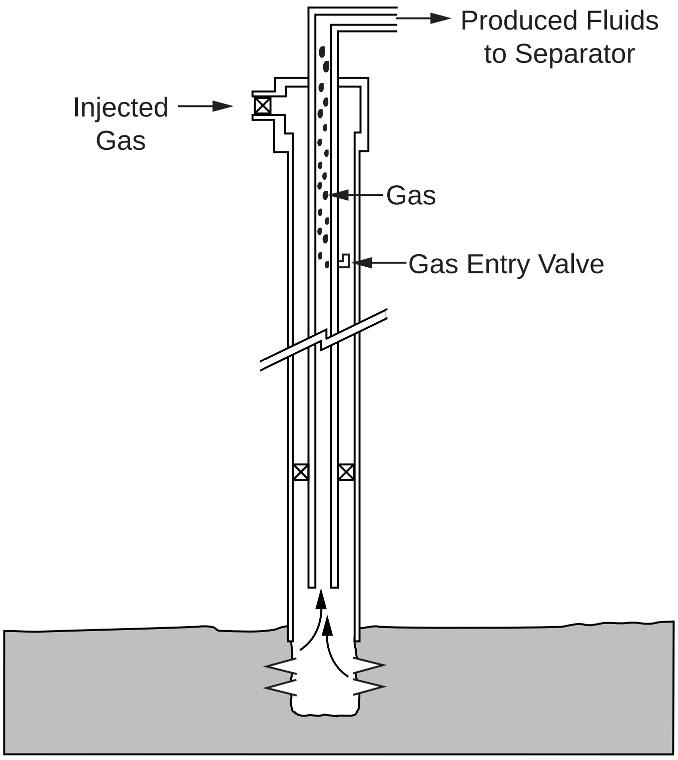


Figure 15
The gas lift process

To understand more clearly the action of gas lift, consider the definition of ΔP_{VL} in equation 8

$$\Delta P_{VL} = \Delta P_{FRICT} + \Delta P_{HHD} + \Delta P_{KE} \quad (11)$$

By injecting gas, the GLR of the flowing fluid is increased, ie, its effective flowing density is reduced and accordingly ΔP_{HHD} is reduced. In addition, the compressibility of the gas will assist in the lift process since as the gas rises up the tubing with the liquid it will expand, causing an increase in the tubing flow velocity. However, as the gas expands it will introduce some increase in the frictional pressure losses which will negate some of the advantage due to the reduced hydrostatic head (refer to equation 8 above). With increasing gas injection volume, the hydrostatic head will continue to decline towards a minimum gradient at very high GOR. The benefits in reduced density may incrementally reduce whilst the increase in frictional pressure loss will increase significantly after a certain gas injection rate. Hence, an optimum gas injection rate will exist, as shown in Figure 16.

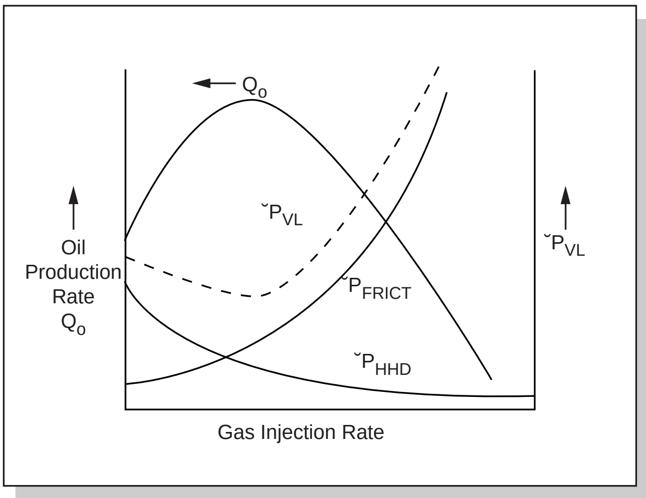


Figure 16
Optimisation of gas injection rate

Consider Equation 10-

Total System Pressure drop,

$$\Delta P_{TOT} = [\Delta P_{RES} + \Delta P_{BHC} + \Delta P_{VL} + \Delta P_{SURF} + \Delta P_{CHOKE}]_Q \qquad (12)$$

If the system undergoes gas lift, then ΔP_{TOT} will be held constant, but ΔP_{VL} will decrease to a minimum and Q will increase through a maximum. Thereafter ΔP_{VL} will increase and Q will decrease as shown in equation 10.

Gas lift is a very effective method of increasing the production rate, provided that the gas is effectively dispersed in the flowing fluid column and the optimum injection rate is not exceeded.

(2) Downhole Pumping

Referring to Equation 7, if a pump system is used, then an additional term is introduced to reflect the supplementary energy provided ΔP_{PUMP}. This will allow a higher production rate to be attained by the well:

$$P_{RES} + \Delta P_{PUMP} = [\Delta P_{RES} + \Delta P_{BHC} + \Delta P_{VL} + \Delta P_{SURF} + \Delta P_{CHOKE}]_Q + P_{SEP} \qquad (13)$$

There are four principal methods which are as follows:

(a) Electric Submersible Pumps

This consists of a multi stage centrifugal pump located at some position downhole usually as an integral part of the tubing string (Figure 17). The requirement for the pump suction to be flooded will dictate setting depth in the well for the pump, depending upon the well pressure. An electric cable run with the production tubing supplies the power from surface to the downhole pump. As an alternative the pump can be run on coiled tubing or on its power cable.

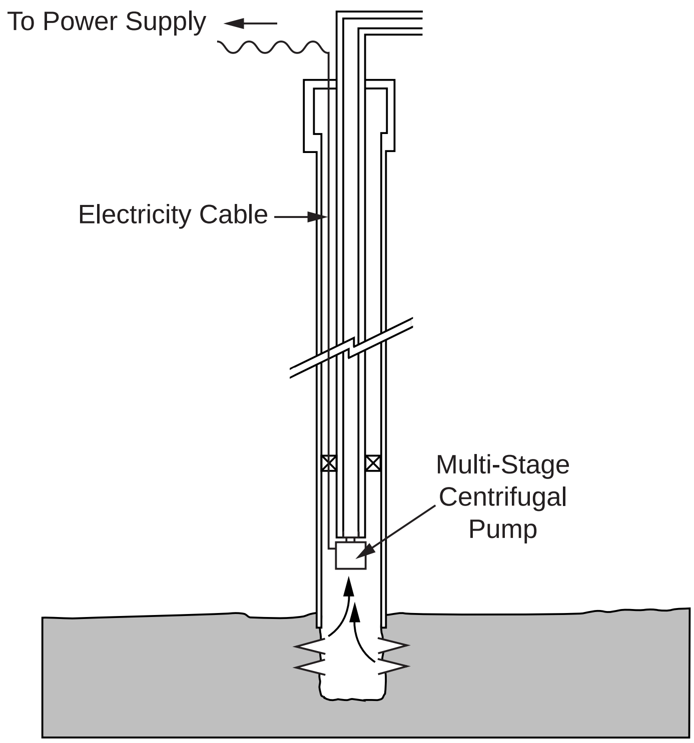


Figure 17
Electrical submersible pump installation

This type of pump is ideally suited to relatively high rates of production, from < 1000 to > 25,000 BLPD.

(b) **Hydraulic Downhole Pumps**

This type of pump, normally run at depth in the tubing string, normally utilises hydraulic fluid power fed down a separate small bore tubing parallel to the tubing string (Figure 18). Alternatively, the fluid can be injected via the casing tubing annulus. Fluid pumped down the line at high pressure powers the drive unit for the downhole pump. The hydraulic fluid usually joins the flowing well fluid in the tubing and returns to surface. Alternatively the fluid can be ducted back to surface separately. The drive unit can range from a reciprocating piston for low flow rates, to a turbine for rates which exceed 20,000 BLPD

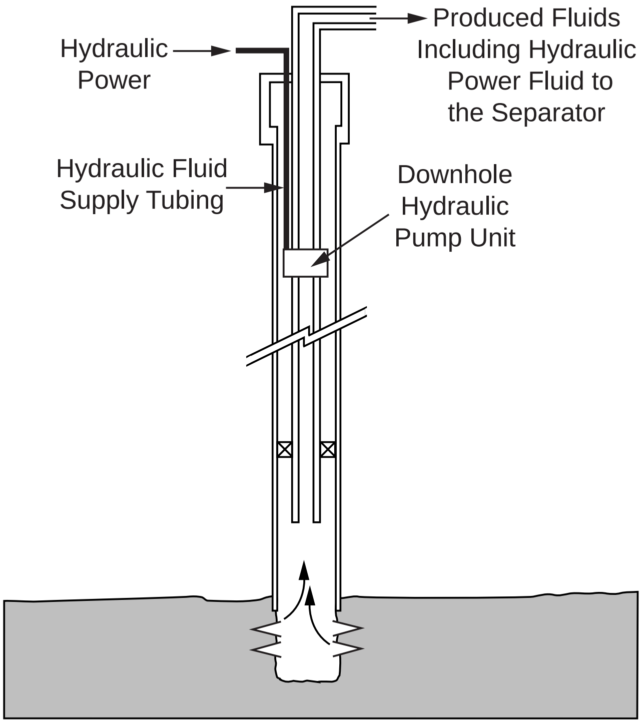


Figure 18
Hydraulic downhole pumps

(c) Sucker Rod Pumping

In this system, a plunger, cylinder and standing valve system is located downhole as part of the tubing string and connected by steel rods to a vertical reciprocation system at surface (Figure 19). The surface reciprocation system is referred to as a "***nodding donkey***"and is driven by a beam suspended on a pivot point and creates reciprocation through a rotary wheel. This type of system is suitable for very low to medium production rates i.e. < 1,000 BLPD and can operate with wells having no flowing bottomhole pressure.

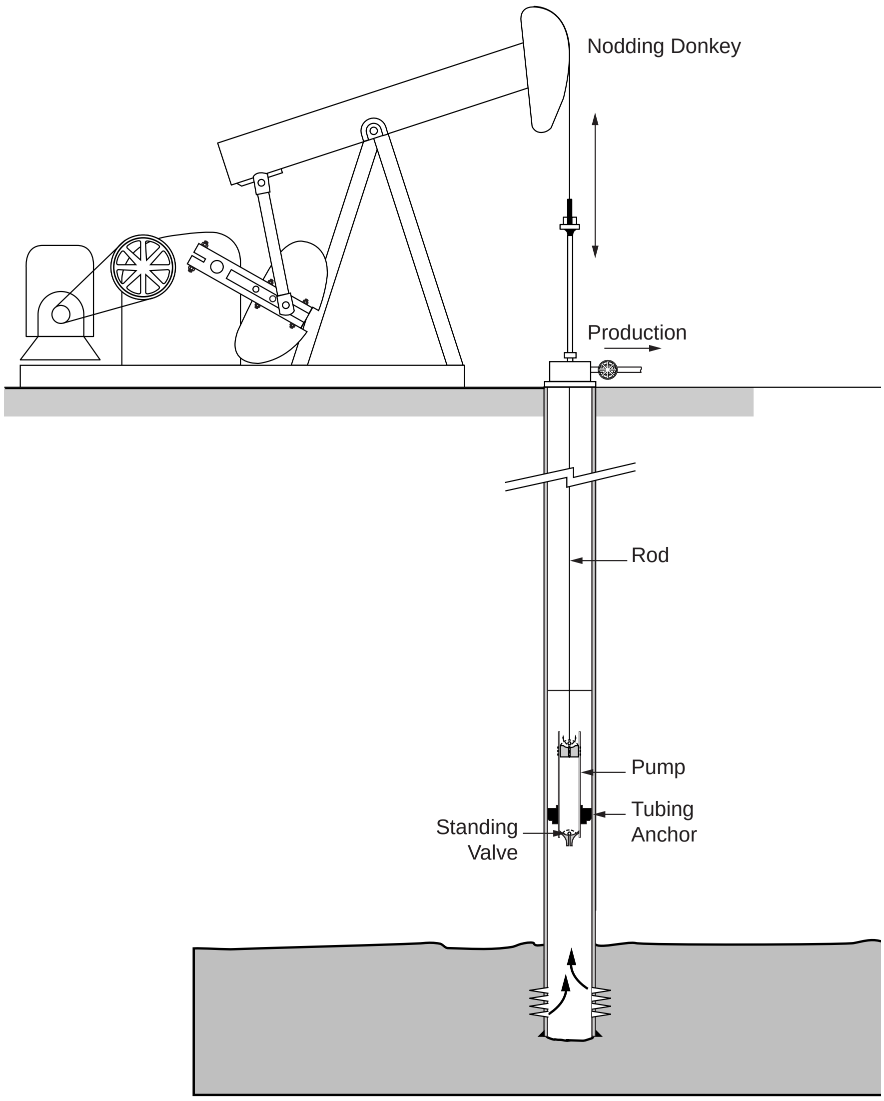


Figure 19
Sucker rod pump system

(d) **Jet Pumping**

In jet pumping, fluid is pumped down to the downhole pump where it is allowed to expand through an orifice and, using the **venturi concept**, this provides suction at the base of the well to lift fluid. The principle of this pump is shown in figure 20.

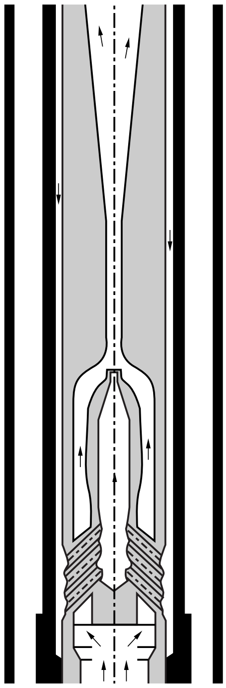


Figure 20
Cutaway drawing of jet pump

Several other pumping systems are available in addition to the above, but they all operate by introducing additional power into the producing system either in the form of electricity, hydraulic power or mechanical reciprocation.

Summary

In this section we have considered general concepts of reservoir performance and well productivity. Key points include:

(a) Reservoir recovery performance and production rate profile is controlled by the reservoir drive mechanism

(b) Reservoir production can be maximised by system pressure drop optimisation

(c) Maintaining production rates can be achieved by fluid injection

(d) Artificial lift processes can maintain or enhance production rates

(e) Gas lift reduces the hydrostatic head pressure loss

(f) Pumps provide additional energy to assist lifting oil to surface

Well design is crucial to the control of fluid movement into the wellbore, their retention in the reservoir and hence maximising recovery and rates of hydrocarbon recovery.

EXERCISES

1. A reservoir has been estimated to contain 100mm STB of oil (bubble point <1500 psia) at a pressure of 5000 psia. Based on an average isothermal compressibility of 20×10^{-6}/psi between the initial pressure and a proposed abandonment pressure of 1500 psia, estimate the recovery volume by depletion drive and the recovery factor considering only the oil phase expansion?

2. Compare the options of gas and water injection for both offshore and onshore oil reservoir applications in terms of potential performance, safety, economics and logistics?

3. For the reservoir in question one, how much oil could be produced and what recovery achieved if the reservoir were connected to an overlying gas cap of 25% volume compared to the oil column and an average compressibility of 400×10^{-6}/psi? Assume that a gravity stable displacement will exist and the well design will permit retention of the gas in the structure.

4. Repeat exercise (3) for the oil reservoir without a gas cap but with an underlying aquifer of a volume 10 times that of the oil column and an average compressibility of 8×10^{-6} / psi

5. Compare and discuss the results of questions 1,3, and 4

SOLUTION

Question 1.

$$\text{Fluid compressibility } C = \frac{dv}{v} = \frac{1}{dP}$$

Fluid expansion volume = $dv_o = C.\ V_o.dP$

For the oil recovery

$V_o = 100 \times 10^6$ STB
$C_o = 20 \times 10^{-6}$ / psi
Pi = 5000 psia
Paban = 1500 psia

$dV_o = 20 \times 10^{-6} \times 100 \times 10^6 \times (5000 - 1500) = 7{,}000{,}000$ STB

Oil recovered by straight depletion drive based on an average fluid compressibility = 7×10^6 STB

$$\text{Recovery factor is } \frac{7}{100} \times 100\% = 7\%$$

Question 3.

In this case the oil recovery will be increased by an amount equal to the expansion of the gas cap as it expands down into the oil rim to fill the voidage created by the oil production

$$dVg = 400 \text{ x} 10^{-6} \text{ x } 25 \text{x } 10^{6} \text{ x } (5000 - 1500)$$

$$= 35 \text{ x } 10^{6} \text{ STB equivalent}$$

$$dVtotal = dV_o + dV_g = 7 \text{x} 10^6 + 35 \text{x} 10^6$$

$$= 42 \text{x} 10^6 \text{ STB}$$

Theoretical total oil recovery is 42 x 10^6 STB which represents a recovery of 42% of the oil in place, assuming all the gas in the gas cap remains in the reservoir.

Question 4.

In this case, the oil recovery will be increased by an amount equal to the expansion of the water filled reservoir as it expands up into the oil rim to fill the voidage created by oil production.

dV_w = 8 x 10^{-6} x 10 x 100 x 10^6 x (5000 – 1500)

= 28 x 10^6 STB

dVtotal = dV_o + dV_w = (7 + 28) x 10^6
= (35 x 10^6 STB

Theoretical total oil recovery is 35 x 10^6 STB which represents a recovery of 35% of the oil in place.

Question 5.

	Np 106 STB	Rec %	Aquifer Vol 10^6 STB	Gas cap Volume 10^6 STB
Oil depletion drive	7	7	0	0
Oil and gas cap	42	42	0	25
Oil and aquifer	35	35	1000	0

Comment. The simple example illustrates the dependence of recovery on both volume and compressibility.

For the water drive and gas drive to achieve the same recovery based purely on compressibility would require an aquifer to gap cap volume ratio of 50:1.

Performance of Flowing Wells 3

CONTENTS

LEARNING OBJECTIVES:

Having worked through this chapter the Student will be able to:

- Compare the alternative scenarios of steady state and semi steady state flow.
- Calculate PI for oil and gas wells in steady state flow
- Discuss impact of well position and drainage area on PI.
- Calculate skin factor due to well geometry effects.
- Explain concepts of flow in pipes and impact of pressure loss components.
- Discuss interaction of hydrostatic head and functional pressure loss gradients for oil, gas, vertical and inclined wells.
- State Bernouilli equation and discuss its application.
- Identify multi-phase flow patterns in vertical, inclined and horizontal pipes.
- Discuss physical property variation in flow up the wellbore for single phase gas and oil flow, and for multi-phase flow.
- List major options for multi-phase flow optimisation and explain different generic assumptions.
- Explain concepts of slip and hold up and appreciate impact on flow efficiency and tubing sizing.
- Discuss concepts of flow pattern maps.
- Explain gradient curves concepts and physical significance of pressure versus depth traverse's.
- Calculate flowing bottom hole pressure based on assumed tubing head pressures and the intake curve of flowing bottomhole pressure versus rate.
- Discuss design and selection of fixed orifice and variable orifice chokes.
- Use nomographs for choke sizing
- Use graphical techniques to predict well flow capacity by matching inflow and vertical flow curves.
- Conduct sensitivity analysis to variable PI, declining average pressure, variable tubing size, increased water and gas oil ratios.

INTRODUCTION

The analysis of flowing well performance rightly occupies an important place in production technology and it is perhaps difficult for us to understand today why it was not extensively investigated in the technical literature until the 1950's. W.E. Gilbert of Shell Oil was one of the early engineers working in this field and most of his work was published in house in the 1940's, although it did not reach the general public until 1954.

His classic paper of that date "Flowing and Gas-Lift Well Performance" is still well worth reading and his concepts of pressure gradient curves, inflow performance relationships (IPR), and graphical solutions of well performance problems are still in universal use today. Here is what he said in his introduction to that paper:

"Production by natural flow rightly tops the list of lifting methods, inasmuch as it produces more oil than all other methods combined. It proceeds with minimum cost in relative absence of operating difficulties; and is relinquished finally in an atmosphere charged with regret, and is supercharged with expletives intended to fortify the conclusion that the stoppage is an irreversible act of Providence. Nevertheless, production men have been haunted for years by the thought that a more definite knowledge of flow performance would suggest means of resuming flow after premature stoppages, permit more effective well control, more appropriate flow-string selections, and serve in general to increase the proportion of oil quantities economically recoverable by natural flow."

Since then, there has been a substantial improvement in our understanding of the various concepts which define well performance. However it would be far from the truth to suggest that our understanding is complete.

In chapter 2 , the concept of the production system was introduced. The production of fluids from the reservoir or the injection of fluids into it , requires the dissipation of energy in the form of fluid pressure. The effective design or evaluation of the performance of a well requires consideration of the pressure loss in the flowing system which includes some or all of the following components :

- the reservoir
- the bottom hole completion
- the tubing or casing
- the wellhead
- the flowline
- the flowline choke
- pressure losses in the separator and export pipeline to storage

The production of oil and gas from a reservoir is intrinsically limited by the pressure in the reservoir. A major task in production engineering and in the design of an effective completion is to optimise the design to maximise oil and gas recovery.

The relative significance of this was illustrated by Duns and Ros who predicted the following distribution of pressure drop for a particular well.

PI BOPD/PSI	Q PRODUCTION RATE BOPD	% OF TOTAL PRESSURE LOSS		
		RESERVOIR	TUBING	FLOWLINE
2.5	2700	36	57	7
5.0	3700	25	68	7
10.0	4500	15	78	7
15.0	4800	11	82	7

Table 1
Pressure loss distribution

Obviously, the majority of pressure loss will occur in the reservoir and tubing and as the productivity of the reservoir increases, the proportion of pressure drop per unit flowrate within the tubing will increase. The specification of the tubing string will thus be crucial to the optimisation of the system production capacity.

Production performance involves matching up the following three aspects:

(1)Inflow performance of formation fluid flow from formation to the wellbore.

(2)Vertical lift performance as the fluids flow up the tubing to surface.

(3)Choke or bean performance as the fluids flow through the restriction at surface.

1 WELL INFLOW PERFORMANCE

1.1 Darcy's Law

The simplest defining relationship is that postulated by Darcy from his observations on water filtration. The Law applies to so-called linear flow where the cross sectional area for flow is constant irrespective of position within the porous media. Further, Darcy's Law applies to laminar flow:

$$\frac{q_r}{A} = U = \frac{-k}{\mu}\left[\frac{dP}{d\ell} - \rho g \frac{dD}{d\ell}\right] \qquad (1)$$

where:

q_r	flowrate of fluid at reservoir conditions	cm^3/sec
A	cross-sectional area for flow	cm^2
U	fluid velocity	cm/sec
P	pressure	atm
ℓ	length of porous media	cm
r	fluid density	gms/cm^3
D	elevation	cm
μ	fluid viscosity centipoise	cp
K	rock permeability darcy	cm^2

In Equation 1, the first term on the right hand side quantifies the effect of viscous forces whilst the second term in parenthesis is the gravitational force effect.

For a horizontal medium i.e. horizontal flow with no gravity segregation:

$dD = 0$

and, hence

$$U = \frac{-K}{\mu} \cdot \frac{dP}{d\ell} \tag{2}$$

Equation 2 becomes:

Since $W = \dfrac{q_r}{A}$

and $q_r = q_s.B$

$$\frac{q_s B}{A} = \frac{K}{\mu} \cdot \frac{dP}{d\ell} \tag{3}$$

where B is the oil formation volume factor and q_sB is the flowrate in reservoir bbls/day i.e. q_r.

In oilfield terms, we would like to obtain results in a more useful system of units, namely:

q_s	stock tank bbl/day
A	ft^2
μ	cp
p	psi
ℓ	ft
K	md

1.2 Darcy's law - linear flow

A linear flow model assumes that:

- flow will be horizontal
- cross sectional area for flow is constant between the inlet and outlet of the porous medium.

If the flowing fluid is assumed incompressible then its density is independent of pressure and the volumetric flowrate is constant and independent of position in the porous media. Thus, Equation 2 can be integrated as follows:

$$\frac{q}{A} = -\frac{K}{\mu} \cdot \frac{dP}{d\ell}$$

$$\frac{q}{A} \cdot d\ell = -\frac{K}{\mu} dP$$

Defining the limits for integration for a linear model as:

At the entry to the porous media

$\ell = 0 \qquad P = P_1$

and at the exit

$\ell = L \qquad P = P_2$

$$\int_o^L \frac{q}{A} \cdot d\ell = -\frac{K}{\mu} \int_{P_1}^{P_2} dP$$

After integrating and substituting for ℓ and P:

$$\frac{q}{A} \cdot L = -\frac{K}{\mu}\left(P_2 - P_1\right)$$

or

$$q = \frac{kA}{\mu} \cdot \left(\frac{P_1 - P_2}{L}\right) \qquad (4)$$

The linear flow model has little widespread application in the assessment of well productivity for real reservoirs since the flow geometry cannot be assumed to be linear.

1.2 Radial Flow Theory for Incompressible Fluids

Production wells are designed to drain a specific volume of the reservoir and the simplest model assumes that fluid converges towards a central well as shown in Figure 1. This convergence will cause an increase in fluid velocity as it approaches the wellbore and, as a consequence, an increase in the pressure gradient.

From the above, it is clear that to model more accurately the geometry of the majority of real flowing systems, a different flow model needs to be developed. To account for the convergence effects of flow, a simplified model based upon the assumption of radial flow to a central well located in the middle of a cylindrical reservoir unit is assumed as shown in Figure 2.

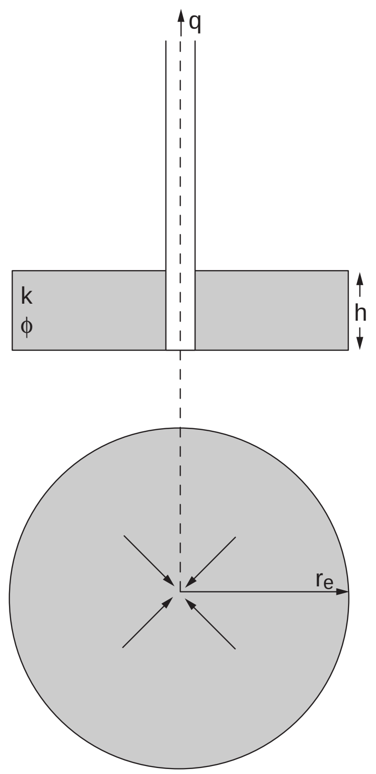


Figure 1
Radial inflow model

The model assumes:

(1) The reservoir is horizontal and of constant thickness h.

(2) The reservoir has constant rock properties of ϕ and K.

(3) Single phase flow occurs to the well bore.

(4) The reservoir is circular of radius r_e.

(5) The well is located at the centre of the reservoir and is of radius r_w.

(6) The fluid is of constant viscosity μ.

(7) The well is vertical and completed open hole, i.e. fluid enters the wellbore through the total height h.

Two cases are of primary interest in describing reservoir production systems:

(1) Fluid flow occurs into the reservoir across the outer boundary at the drainage radius r_e. If the volumetric flowrate into the reservoir equals the production rate of fluids from the reservoir, the reservoir is said to be at ***steady state*** conditions i.e. pressure at any part of the reservoir is constant irrespective of the duration of production**.**

(2) If no fluid flow occurs across the outer boundary then the production of fluids must be compensated for by the expansion of residual fluids in the reservoir. In such a situation, production will cause a reduction in pressure throughout the reservoir unit. This situation is described as ***semi steady state or pseudo steady state***.

The behaviour of the fluid system will also influence the fluid flow equations. Fluids whose density is independent of pressure are referred to as incompressible and will be characterised by a constant volumetric flowrate independent of position and pressure within the reservoir. Water and the heavier crude oils can be classified as incompressible fluids, though slightly compressible when existing as a single phase. Fluids whose density is pressure-dependent are termed compressible fluids; gas is an example of such a reservoir fluid.

1.2.1 Steady State - Radial Flow of an Incompressible Fluid

Here, we consider an incompressible fluid, ie, one in which the density is independent of pressure and hence of position.

The geometrical model assumed for the derivation of the flow equations is given in Figure 1 and the terminology defined in Figure 2.

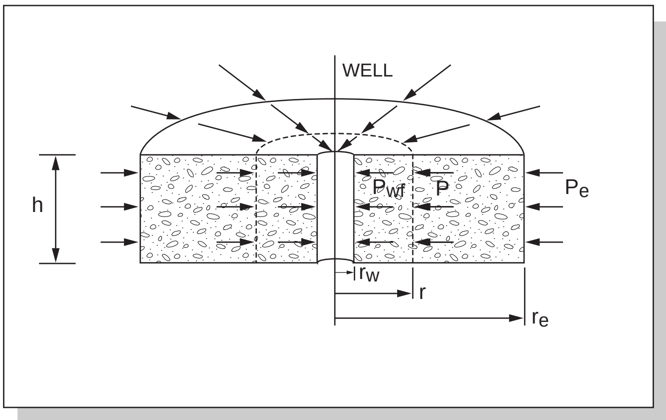


Figure 2
Nomenclature for ideal cylindrical flow

At a radius r the cross sectional area available for flow in 2πrh and the velocity U for a flowrate of q is given by:

$$U = \frac{q}{2\pi rh} \qquad (5)$$

Using Darcy's Law expressed in radial coordinates:

$$U = \frac{K}{\mu} \cdot \frac{dP}{dr} \tag{6}$$

Combining (5) and (6):

$$\frac{q_r}{2\pi rh} = \frac{K}{\mu} \cdot \frac{dP}{dr} \tag{7}$$

or

$$dP = \frac{q_r}{2\pi kh} \cdot \frac{dr}{r} \tag{8}$$

Equation 8 can be integrated between the limits of

(i) at the inner boundary i.e. the wellbore sand face.
$r = r_w \quad P = P_w$

(ii) at the outer boundary i.e. the drainage radius.
$r = r_e \quad P = P_e$

Substituting

$$\int_{P_w}^{P_e} dP = \frac{q_r \mu}{2\pi kh} \int_{r_w}^{r_e} \frac{dr}{r} \tag{8a}$$

After integration and substitution of the boundary conditions.

$$\left[P_e - P_w\right] = \frac{q_r \mu}{2\pi kh} \ln\left(\frac{r_e}{r_w}\right) \tag{9}$$

where:

(1) $[P_e - P_w]$ is the total pressure drop across the reservoir and is denoted the ***drawdown***.

(2) q_r is the fluid flowrate at reservoir conditions.

If the production rate measured at standard conditions at surface i.e. q_S then $q_S.B = q_r$

Equation (9) becomes:

$$\left[P_e - P_w\right] = \frac{q_s \mu B}{2\pi kh} \ln\left(\frac{r_e}{r_w}\right) \tag{10}$$

In field units:

$$\left[P_e - P_w\right] = \frac{1}{7.082x10^{-3}} \frac{q_s \mu B}{kh} \ln\left(\frac{r_e}{r_w}\right) \quad (11)$$

where P and q_s have units of psi and STB/day respectively.

A plot of P_w versus r indicates how the pressure declines as the incompressible fluid flows and converges towards the wellbore (Figure 3). In addition from equation 11, it can be seen that a plot of P_w versus q_s will give a straight line (Figure 4).

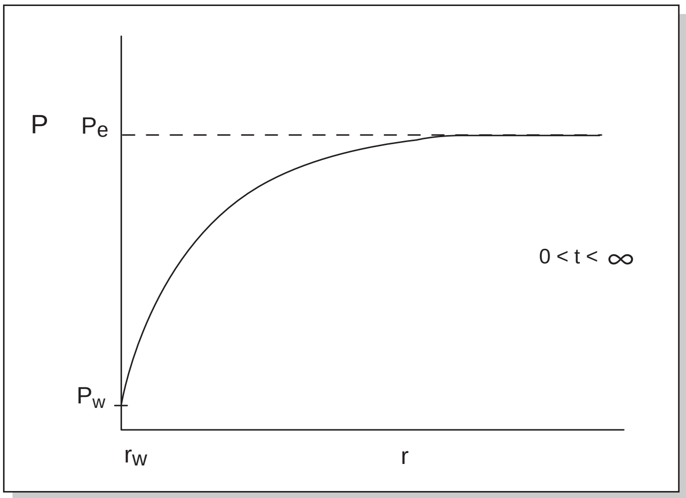


Figure 3
Radial flow ideal pressure profile

The steady state radial flow equation for an incompressible fluid only truly applies when the reservoir is infinite in size and no pressure depletion occurs with time. It can be approximated by the performance of a well in a reservoir supported by an infinite aquifer provided the changing fluid mobility effects are negligible. It can also apply approximately for the following types of depletion provided little drop in reservoir pressure is experienced and assuming no marked changes occur in the properties of the flowing phases:

(1) Highly supportive reservoir pressure maintenance with water injection or gas reinjection.

(2) Reservoir production associated with a substantial expanding gas cap.

1.2.2 Semi Steady State Radial Flow of a Slightly Compressible Fluid.

Under these conditions, flow occurs solely as a result of the expansion of fluid remaining within the reservoir. The reservoir is frequently defined as being bounded since it is assumed that no flow occurs across the outer boundary. Figure 5.

Hence:

$$\left(\frac{dP}{dr}\right)_{r=r_e} = 0$$

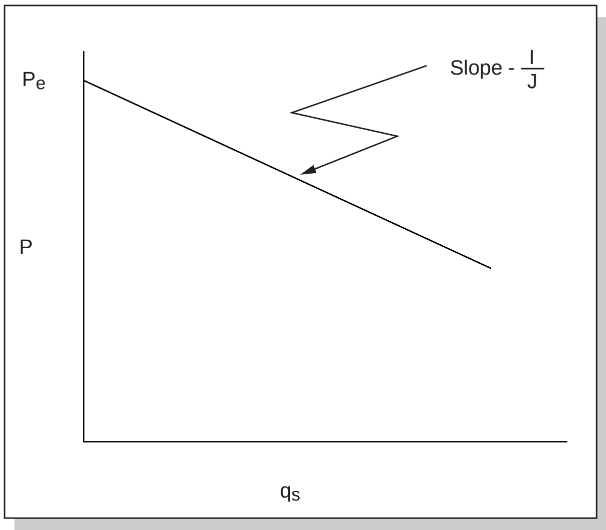


Figure 4
The productivity index plot for a single phase incompressible fluid

i.e. no pressure gradient exists across the outer boundary. Since the production is due to fluid expansion in the reservoir, the pressure in the reservoir will be a function of time and the rate of pressure decline dP/dt will be constant and uniform throughout the system.

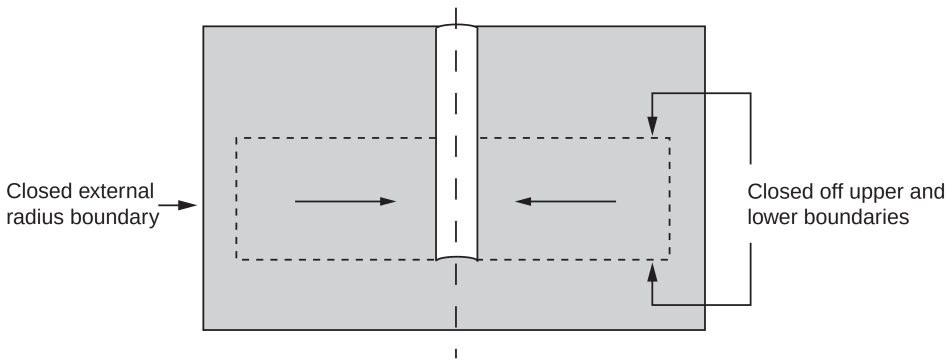


Figure 5
Semi steady state model - closed boundaries.

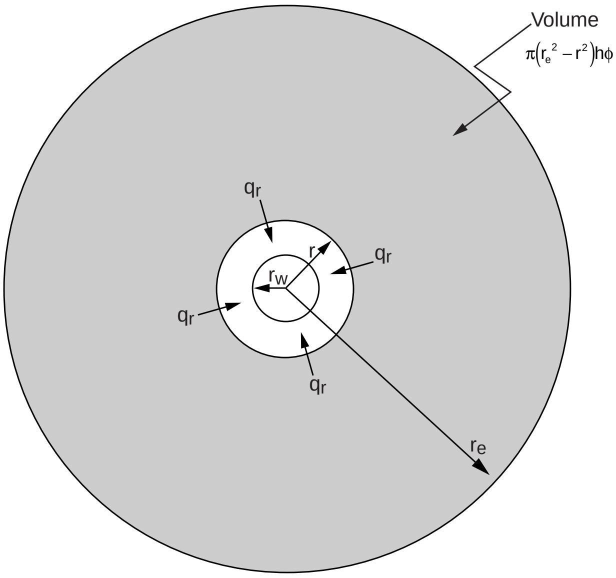


Figure 5a
Fluid production at 'r' is provided by expansion of reservoir fluid/rock between radius 'r' and the outer boundary

The pressure profile with radius for the system will be constant but the absolute values of pressure will be time dependent.

Production, since it is based upon the volumetric expansion of fluids in the reservoir, will depend upon the fluid compressibility which is defined as "the change in volume per unit volume per unit drop in pressure", i.e.

$$C = -\frac{1}{V} \cdot \frac{\partial V}{\partial P} \tag{12}$$

where C is the isothermal coefficient of compressibility. For a reservoir production system as discussed in section 2, a reduction in pressure within the reservoir will cause an expansion in all of the fluid phases present, ie, potentially oil, gas and water as well as a reduction in the pore space due to rock expansion. The isothermal compressibility should, for realistic evaluation, be the total system compressibility C_t.

For most reservoirs, C_t is usually small, hence large changes in pressure will generate only limited fluid expansion and corresponding production.

The application of Darcy's law with the system compressibility equation applied to to cylindrical reservoir volume , results in an equation which needs to be solved analytically to give :

$$q = \frac{2\pi kh\left(P_e - P_w\right)}{\mu\left[1n\left(\frac{r_e}{r_w}\right) - \frac{1}{2} + \frac{r_w^{\ 2}}{r_e^{\ 2}}\right]} \tag{13}$$

Since, $r_w << r_e \left(\frac{r_w}{r_e}\right)^2 \rightarrow 0$, giving (14)

$$\left[P_e - P_w\right] = \frac{q\mu}{2\pi kh}\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right]$$

which, when expressed in field units, becomes:

$$\left[P_e - P_w\right] = \frac{1}{7.08x10^{-3}}\frac{q\mu}{kh}\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right] \qquad (15)$$

Since, for a bounded reservoir, P_e has no physical significance, once the reservoir starts to deplete, the produceability of the reservoir at any point in time is best defined by a volumetrically averaged reservoir pressure. This pressure would only be realised if the well were closed in and pressure equilibrated throughout the drainage volume and the average reservoir pressure in thus defined by:

$$\overline{P} = \frac{\int_{r_w}^{r_e} P \cdot dV}{\int_{r_w}^{r_e} dV} \qquad (16)$$

In addition since the reservoir is bounded, with continuous production the average reservoir pressure will continuously decline.

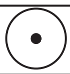
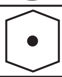
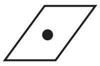
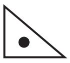
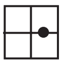
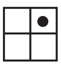
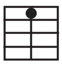
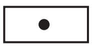
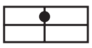
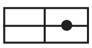
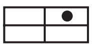
After evaluating $\overline{P}$ from Equation 16, it can be substituted into the previous semi-steady state radial flow derivation, Equation 14, to obtain after integration:

$$\left[\overline{P} - P_w\right] = \frac{q_s\mu B}{2\pi kh}\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4}\right] \qquad \text{(Darcy units)} \qquad (17)$$

The basic assumption in the above derivation is that the reservoir is circular and penetrated by a central well. In reality even a very large reservoir penetration by a number of wells will behave as if each well drains a portion of the reservoir. Each of these drainage volumes will be non-circular (Table 2). Dietz developed shape factors to account for depletion in wells located in other drainage shapes or where the well is located off centre. The shape of the drainage area will be dictated by the no flow boundaries.

$$\left[\overline{P} - P_w\right] = \frac{q_s\mu B}{4\pi kh}\left[\frac{\ln 4A}{\gamma \cdot C_A \cdot r_w^{\ 2}}\right] \qquad \text{(Darcy units)} \qquad (18)$$

where, γ is the Eulers constant and for any specific drainage shape, C_A can be substituted by a number obtained from the tabulation of factors prepared by Dietz (Table 2).

	C_A	In C_A	Exact for t_{DA}>	Less than 1% error for t_{DA}>	Use infinite system solution with less than 1% error for t_{DA}<
	31.62	3.4538	0.1	0.06	0.10
	31.6	3.4532	0.1	0.06	0.10
	27.6	3.3178	0.2	0.07	0.09
	27.1	3.2995	0.2	0.07	0.09
	21.9	3.0865	0.4	0.12	0.08
	0.098	-2.3227	0.9	0.60	0.015
	30.8828	3.4302	0.1	0.05	0.09
	12.9851	2.5638	0.7	0.25	0.03
	4.5132	1.5070	0.6	0.30	0.025
	3.3351	1.2045	0.7	0.25	0.01
	21.8369	3.0836	0.3	0.15	0.025
	10.8374	2.3830	0.4	0.15	0.025
	4.5141	1.5072	1.5	0.50	0.06
	2.0769	0.7309	1.7	0.50	0.02
	3.1573	1.1497	0.4	0.15	0.005

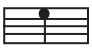



Table 2
Shape factors for various closed single - well drainage areas

1.3 Radial Flow Theory for Single Phase Compressible Fluids

Oil, in most cases, can be considered as only slightly compressible and as the average molecular weight of the crude increases so the compressibility normally declines. Gases, however, are highly compressible fluids, containing only the lighter hydrocarbon molecules. The prediction of inflow performance for gas wells is more complex than for oil for the following reasons:

(1) Gas viscosity is dependent upon pressure.

(2) The isothermal fluid compressibililty is highly dependent upon pressure and hence as the gas flows towards the wellbore it expands substantially. Hence the volumetric flowrate of gas rapidly increases as the gas nears the wellbore and flows up the tubing to surface.

Again, by the application of Darcy's Law, we can write for a gas system at a specific radius, r:

$$Q_R = \frac{1.1271\,(2\pi rh)}{1000\mu} k \frac{dP}{dr} \tag{19}$$

where Q_R is the gas flowrate in reservoir bbls/day.

Converting the gas flowrate to standard conditions, ie, Q_s in SCF/d using the real gas law written for both standard and reservoir conditions :

$$Q_s = 5.615\ Q_R \cdot \frac{P_R \cdot T_s \cdot Z_s}{P_s \cdot T_R \cdot Z_R} \tag{20}$$

where the subscripts s and R refer to standard and reservoir conditions respectively. Upon back substitution, into equation 19, we derive the general differential equation for gas well inflow performance:

$$\frac{3.9764 \text{ x } 10^{-2}\ K \cdot h \cdot T_s \cdot Z_s}{Q_s \cdot P_s \cdot T_R \cdot Z_R \cdot \mu}\ P \cdot dP = \frac{dr}{r} \tag{21}$$

As before, this generalised equation can be solved for both the steady and semi-steady state flow conditions.

1.3.1 Steady State Radial Flow for a Gas System

The basic assumption for the solution of the radial flow equation under steady state conditions is that the volumetric flowrate is constant and independent of radius.

The difficulty associated with integrating Equation 21 is that both μ and Z are functions of pressure.

There are both rigorous and simplified approaches to the solution of this equation for gas.

(a) Rigorous solution - gas pseudo pressure approach.

The standard conditions normally assumed are:

$T_S = 520^\circ R$ $\quad P_S = 14.7$ psia $\quad$ and $Z_S = 1.0$

and, upon substitution in Equation (21), we obtain:

$$\frac{0.703\ \mathrm{kh}}{\mathrm{Q_s} \cdot \mathrm{T}} \cdot 2\int_{\mathrm{P_w}}^{\mathrm{P_e}} \frac{\mathrm{P}}{\mu \mathrm{z}} \cdot \mathrm{dP} = \int_{\mathrm{r_w}}^{\mathrm{r_e}} \frac{\mathrm{dr}}{\mathrm{r}} = \ln\left(\frac{\mathrm{r}}{\mathrm{r_w}}\right) \tag{22}$$

The integral term on the LHS is the Kirchoff integral commonly referred to as the real gas pseudo-pressure function m(P) or ψ.

$$\mathrm{m}(\mathrm{P}) = 2\int_{\mathrm{P_w}}^{\mathrm{P}} \frac{\mathrm{P}}{\mu \mathrm{z}} \cdot \mathrm{dP} \tag{23}$$

The real gas pseudo pressure is normally evaluated with reference to a standard condition or datum reference, thus:

$$2\int_{P_w}^{P} \frac{P}{\mu z} \cdot dP = 2\int_{P_o}^{P} \frac{P}{\mu z} \cdot dP - 2\int_{P_o}^{P_w} \frac{P}{\mu z} \cdot dP \tag{24}$$

$$= \psi_e - \psi_w \tag{25}$$

Hence, Equation (22) becomes by rearrangement:

$$\psi_e - \psi_w = \frac{Q_s \cdot T}{0.703\ \mathrm{kh}} \cdot 1n \frac{r_e}{r_w} \tag{26}$$

where Qs is measured in MSCF/day.

or:

$$\psi_e - \psi_w = \frac{1422\ Q_s' \cdot T}{k \cdot h} \cdot 1n \frac{r}{r_w} \tag{27}$$

where Q_s = MSCF/day

The presence of the real gas pseudo pressure terms on the LHS of Equation 27 make it more complicated to utilise compared to the equation for incompressible fluids.

(b) Approximate solution for single phase gas inflow - average pressure or P^2 approach.

There are a number of simplified solution techniques including the P^2 Technique .

Referring to Equation 22, this technique involves removing (μz) from the integrand and evaluating it at an arithmetic average pressure for the flowing system i.e. the average of the sum of the inner and outer boundary pressures.

ie

$$\frac{0.703\ \mathrm{Kh}}{\mathrm{Q_s\ T_R}} \quad \frac{2}{(\mu z)_{ave.}} \int_{P_w}^{Pe} P \cdot dP = 1n\frac{r_e}{r_w} \tag{28a}$$

and hence

$$\frac{0.703\ \mathrm{Kh}}{\mathrm{Q_s\ T}} \quad \frac{2}{(\mu z)_{ave.}} \left(Pe^2 - P_w{}^2\right) = 1n\frac{r}{r_w} \tag{28b}$$

i.e.

$$Pe^2 - P_w{}^2 = 1422\frac{Q_s' \cdot T}{K \cdot h} \cdot (\mu z)_{ave.} \left[1n\frac{r_e}{r_w}\right] \tag{29}$$

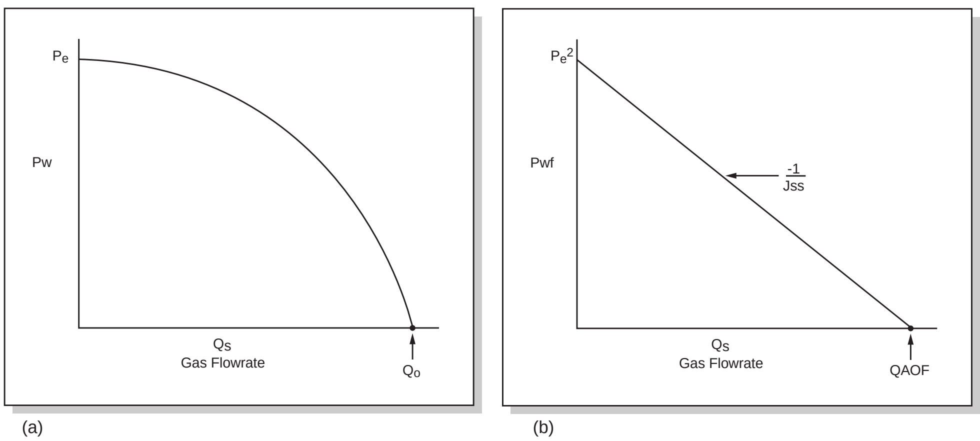
where Q_s = MSCF/day

and (μz) is evaluated at $\left[\dfrac{Pe + P_w}{2}\right]$

If we plot P_w versus Q_s we obtain a plot as shown in figure 6(a) note that the incremental increase in production rate decline as bottom hole pressure declines.

If we plot p_w^2 versus Q_s we obtain a linear plot, assuming the P^2 approach is valid, as shown in figure 6(b).

Figure 6 (a) Gas well inflow performance 6 (b) P^2 plot if gas well performance



1.3.2 Semi-Steady State Flow for a Gas System

Using the bounded reservoir assumption and employing the definition of isothermal compressibility, we can obtain the equation as:

$$\overline{\psi} - \psi_w = \frac{1422\ Q'_s\ T}{K\ h}\left[1n\frac{r_e}{r_w} - \frac{3}{4}\right] \qquad (30)$$

in terms of the real gas pseudo pressure term y.

In terms of the P^2 format:

$$Q'_s = \frac{703\ x\ 10^{-6}\left[\overline{P}^2 - P_w{}^2\right]}{T_R\ (\mu z)_{ave}\left[1n\frac{r_e}{r_w} - \frac{3}{4}\right]} \qquad (31)$$

1.4 Multiphase Flow Within The Reservoir.

So far we have discussed the cases of single phase liquid and single phase gas in flow. Most oil reservoirs will produce at a bottom hole pressure below the bubble point either:-

(1) Initially where the reservoir is saturated

(2) Or after production where the pressure in the pore space declines below the bubble point.

The complexity of modelling the inflow in this case is that we have at that stage moved to a position where we have multiphase flow. The flow of the individual phase is governed by the pore space occupancy or saturation of that phase i.e. S_o or S_g, which is in itself a function of pressure. Further, each of the phases will only become mobile when its saturation exceeds a critical value. Below this value the phase is static but the volumetric pressure of that phase constrains the flow of the mobile phase i.e. the relative permeability of the mobile phase for example for a gas oil system.

	K_o	$= K_{ro}\ .K_{ABS}$	(32a)
where	K_{ro}	$= f(S_o)$	(32b)
and	$S_o + S_g$	$= 1.0$	(32c)

where K_o = effective permeability to oil
K_{ro} = relative permeability to oil
S_o = oil phase saturation of the pore space
K_{ABS} = absolute permeability of the rock
S_g = gas phase saturation of the pore space

Similar equations can be written for the gas phase. The relative permeability of the system is defined by a series of saturation dependent curves which are specific to the fluids and rock system e.g. Figure 7.

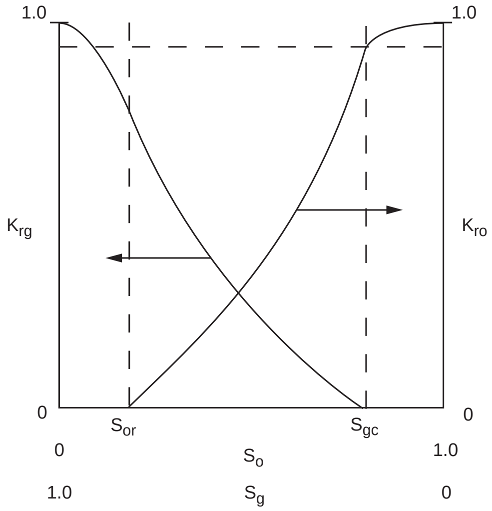


Figure 7
Typical oil - gas relative permeability curve.

Since the fluid system properties are a dynamic formation of pressure and position, we can only rigorously model inflow in such situations using implicit reservoir simulation. A number of approximate techniques have been proposed such as those of Vogel etc.

In Vogels' work he simulated the performance of a solution gas drive reservoir, plotted the data and attempted to derive a generalised relationship. The technique used a system of dimensionless flow rates and pressure as follows:-

$$Q_D = \text{dimensionless liquid flowrate} = \frac{Q}{Qmax}$$

where Q_{max} = flowrate with zero bottom hole pressure

one $P_D = \text{dimensionless bottomhole pressure} = \dfrac{Pwf}{\bar{P}}$

where P_{wf} = bottomhole pressure at a finite liquid rate Q

$\bar{p}$ = Static or closed in average reservoir pressure.

Vogel developed an approximate dimensionless curve as shown in Figure 8. An equation was best fitted to the curve and had the general form of :

$$\frac{Q}{Qmax} = 1 - 0.2\left(\frac{Pwf}{\bar{P}}\right) - 0.8\left(\frac{Pwf}{\bar{P}}\right)^2 \qquad (33)$$

A plot of P_{wf} versus Q is shown in Figure 9(a) and 9(b) for an oil reservoir initially producing at a pressure above the bubble point and at or below the bubble point respectively.

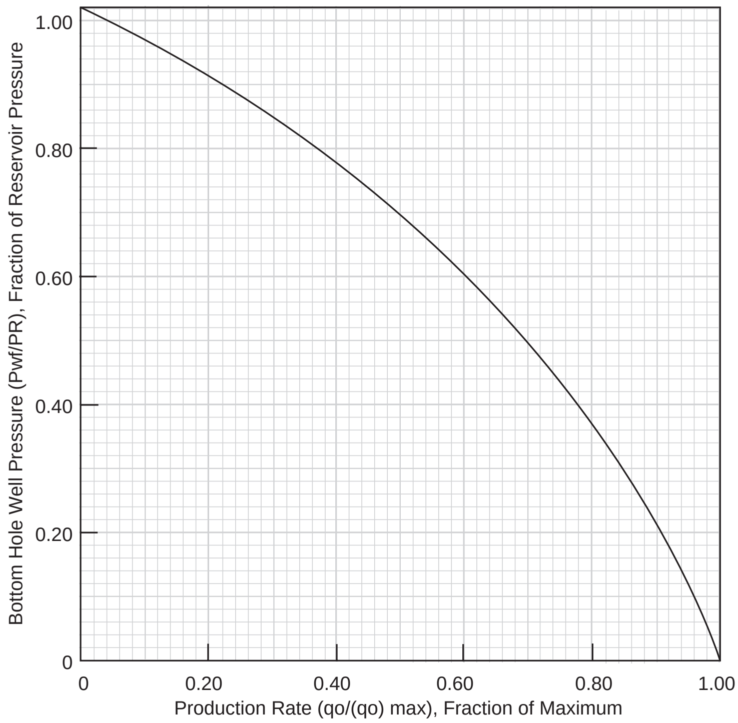


Figure 8
Inflow performance relationship for solution - gas drive reservoir (after Vogel)

$$\frac{q_o}{q_{o(max)}}$$

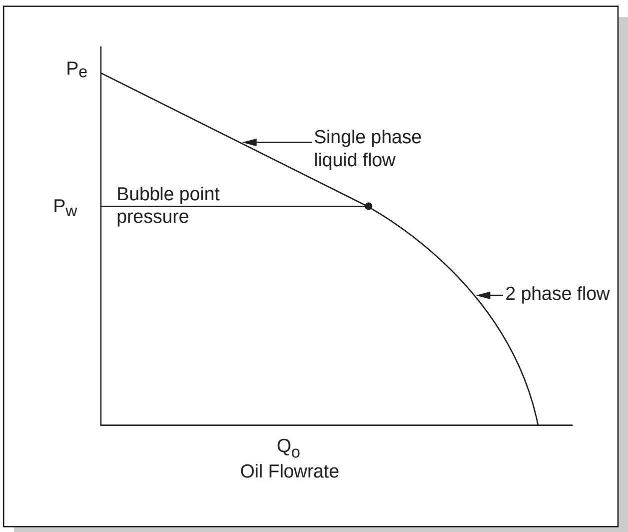


Figure 9(a)
Reservoir producing with a pressure initially above the bubble point

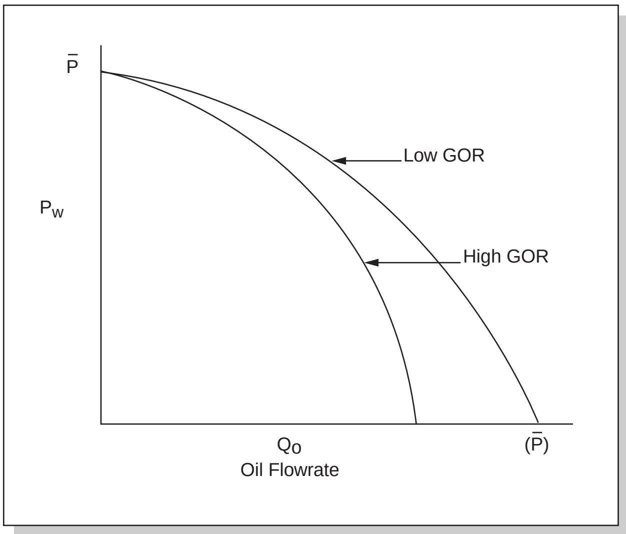


Figure 9(b)
Initial reservoir pressure at or below bubble point

1.5 Non Darcy Flow

Darcy's law only applies to laminar flow situations. This is considered to be a valid assumption for the majority of oil wells where in in situ velocities even around the wellbore are relatively low. For gas wells and some very high flowrate (light crude) oil wells, the volumetric expansion as fluid approaches the wellbore is very high and this can result in turbulent flow. In such cases, we use a modified form of the Darcy equation, known as the Forchheimer equation, where we add to the Darcy viscous flow term $\mu.U/K$, a quadratic velocity term to account for the inertial flow as follows:

$$\frac{dP}{dr} = \frac{\mu\,\mathrm{U}}{\mathrm{K}} + \beta\,\rho\,U^2 \qquad (34)$$

Note that the pressure distribution in the reservoir is now a quadratic function of fluid velocity. The non-Darcy component due to turbulent flow is normally handled as an additional pressure loss ΔP_{ND}.

1.6 Productivity Index

The productivity index of PI provides a measure of the capability of a reservoir to deliver fluids to the bottom of a wellbore for production. it defines the relationship between the surface production rate and the pressure drop across the reservoir, known as the drawdown.

$$\mathrm{PI} = \mathrm{J} = \frac{q_s}{P_e - P_w}\ \mathrm{STB/d/psi} \qquad (35)$$

In the above definition, it is assumed that the entire thickness of the formation is producing fluid. To further assist in defining productivity, taking into account the thickness of producing interval, we can define the Specific Productivity Index Js,

$$J_s = \frac{q_s}{\left(P_e - P_w\right)\cdot h}\ \mathrm{STB/d/psi/ft} \qquad (36)$$

For North Sea wells, productivity indices vary from <10 to over 500 STB/d/psi.

1.6.1 PI for Steady State Incompressible Flow

We can, by rearrangement, get an expression for J_{SS}.

$$J_{ss} = \frac{q_s}{P_e - P_w} \frac{7.082 \; x \; 10^{-3} \text{ kh}}{\mu B \; ln \left[\frac{r_e}{r_w} \right]} \tag{37}$$

From the above, it is clear that J will be a constant if μ, B and K remain constant. A plot of P_w versus Qs should be a straight line of slope $-\frac{1}{J}$, with an intercept on the ordinate axis of Pe.

1.6.2 PI for Semi-Steady State Incompressible Flow

In the case of a bounded reservoir, the pressure in the reservoir is time dependent which means that it must be defined on an average basis.

$$J_{sss} = \frac{q_s}{\overline{P} - P_w} \tag{38}$$

From Equation 17 we can define

$$J_{sss} = \frac{7.082 \text{ x } 10^{-3} \text{ kh}}{\mu B \left(1n \frac{r_e}{r_w} - \frac{3}{4} \right)} \tag{39}$$

Again, provided the fluid and rock properties (μ, B and K) are constant, the PI should be constant, irrespective of the degree of depletion. Thus, as for the steady state case, a straight line relationship exists between P_w and q_s.

1.6.3 PI for a Gas Reservoir in Steady State Flow

For gas wells, as discussed earlier, the equations commonly involve a P^2 term and hence the PI is redefined in terms of this.

$$PI = \frac{Q_s}{P_e^{\,2} - P_w^{\,2}} \tag{40}$$

Thus, from Equation 28

$$J_{SSG} = \frac{0.703 \text{ Kh}}{T(\mu Z)_{ave} \; 1n \left[\frac{r_e}{r_w} \right]} \tag{41}$$

In Equation 41 the parameters, assuming no change in the fluid and reservoir properties, should remain constant. Hence, J should be a constant. If a graph of P^2

versus Qs is drawn, a straight line should result of slope $-\frac{1}{J}$, with an ordinate intercept of P_e^2 and an abscissa intercept of Q_{AOF}, defined as being the Absolute Open Flow potential of the reservoir.

1.7 Perturbations from Radial Flow Theory for Single Phase Flow

In the previous sections, the inflow performance relationships were derived on the assumption that true radial flow occurred (into the wellbore) across the entire thickness of the formation which was assumed to be isotropic and homogeneous. In reality, such a situation rarely occurs and the basic process of drilling and completing a well will cause changes in the condition of the physical flow process. These perturbations to radial flow, as depicted in Figure 10, may comprise the following:

(1) A zone of permanent or temporary permeability impairment around the borehole due to mud, completion fluid and possibly cement filtrate invasion around the drilled borehole.

(2) A large number of wells are cased off through the production zone and, to obtain communication between the formation and the wellbore, they require to be perforated. The process of perforating creates a limited number of small hole entry points for fluid to flow into the wellbore. The convergence to the perforation will cause additional pressure loss due to streamline interactions but this can be offset by near wellbore bypassing of flow into the perforation tip.

(3) Often, only a small section of the reservoir is to be perforated and this is termed a partial completion of the reservoir. Again, the production of fluid will be impeded by flow convergence and will only be truly effective if the rock possesses reasonable vertical permeability.

(4) The wells, particularly in offshore environments, may be directionally drilled and they pass through the reservoir at an angle. These deviated wells provide a greater cross sectional area of borehole wall for flow between the borehole and the reservoir.

(5) The presence of fractures, either induced or natural, can also cause deviations from radial flow since the resistance to flow within the fractures will be much less than that in the reservoir and hence they will act as preferential flow paths towards the wellbore.

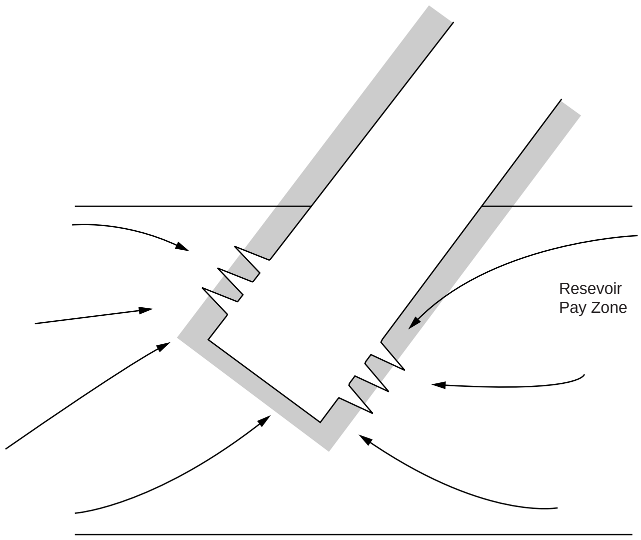


Figure 10
Perturbations to radial flow theory

All the above perturbations from radial flow theory will generate an extra pressure drop component which will affect the magnitude of the actual bottomhole flowing pressure, Pwf.

$$P_{wf_{actual}} = P_{wf_{ideal}} - \Delta P_{SKIN} \tag{42}$$

where $P_{wf\,actual}$ is the actual bottom hole flowing pressure calculated by considering the perturbations to radial flow theory and $P_{wf\ ideal}$ is the idealised bottomhole flowing pressure which assumes true radial flow. ΔP_{SKIN} is the additional pressure loss associated with the perturbation(s). It should be noted that most of the perturbations will cause the ΔP_{SKIN} to be positive and accordingly

$$P_{wf_{actual}} < P_{wf_{ideal}} \tag{42a}$$

However, for fractures and for deep perforations with limited flow convergence, there will be less resistance to flow and hence

$$P_{wf_{actual}} > P_{wf_{ideal}} \tag{42b}$$

The pressure drop associated with these near wellbore phenomena is termed a SKIN and is generally defined as a dimensionless skin factor, S:

$$\mathrm{S} = \frac{\Delta P_{SKIN}}{\dfrac{q_s \mu B}{2\pi kh}} \qquad \text{Darcy units} \tag{43}$$

The effects of skin on the bottomhole pressure are depicted in Figure 11.

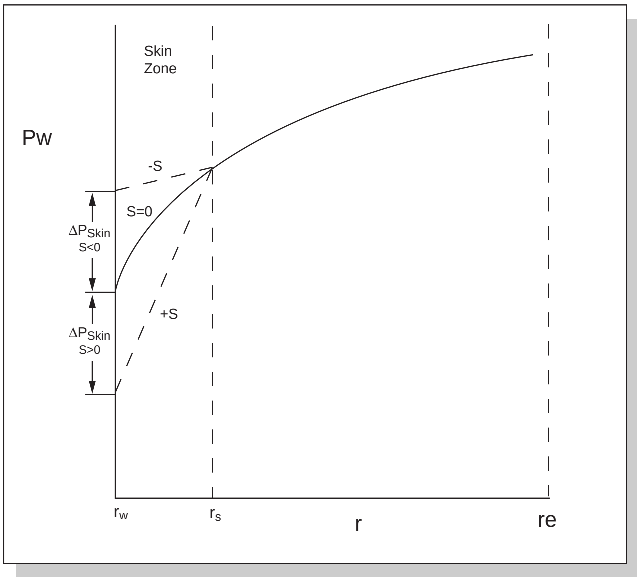


Figure 11
Effect of skin on P_{wf}

A dimensionless skin factor can be defined for each of the radial flow perturbations described above. Some of the skin factors can be estimated given a knowledge of the completion conditions and configurations.

Previously, equations were developed which related the pressure drawdown across the reservoir to the flowrate and other parameters. The actual drawdown across the reservoir when a skin exists, ΔP_{actual}, can be related to the ideal drawdown predicted from radial flow theory ΔP_{ideal} and the skin pressure drop ΔP_{SKIN} by:

$$\Delta P_{wf_{actual}} = \Delta P_{wf_{ideal}} + \Delta P_{SKIN} \tag{44}$$

ie, for the steady state radial flow case.

$$\left[P_e - P_{wf_{actual}}\right] = \left[P_e - P_{wf_{ideal}}\right] + \Delta P_{SKIN} \tag{45}$$

$$where\ \Delta P_{SKIN} = \left[P_{wf_{ideal}} - P_{wf_{actual}}\right]$$

Since ΔP_{SKIN} was defined as

$$\Delta P_{SKIN} = \frac{q_s \mu B}{2\pi kh} \cdot S \tag{46}$$

in Darcy units

or

$$\Delta P_{SKIN} = 141.2 \ \frac{q_s \mu B}{kh} \cdot S \qquad (47)$$

in field units

we can simply add the ΔP_{SKIN} to the radial flow expressions developed earlier e.g. for steady state flow of an incompressible fluid, by adding in the skin pressure drop:

$$\left[P_e - P_{wf_{actual}}\right] = 141.2 \ \frac{q_s \mu B}{kh}\left[\ln\left(\frac{r_e}{r_w}\right) + S\right] \qquad (48)$$

For a compressible fluid such as gas, the dimensionless skin factor S is defined as

$$\Delta p_{\ SKIN} = 1422 \frac{Q_s{}' T}{Kh} \cdot S \qquad (49)$$

and, accordingly using Equation 27 we can obtain for a gas well

$$\psi - \psi_w = 1422 \ \frac{Q_s{}' T}{Kh}\left[\ln\left(\frac{r_e}{r_w}\right) + S\right] \qquad (50)$$

2. TUBING PERFORMANCE

From Table 1 it can be seem that the pressure loss in the tubing can be a significant proportion of the total pressure loss. However its production is complicated by the number of phases which may exist in the tubing. In this section we wish to emphasise the impact and importance of the tubing pressure drop and its physical rather than theoretical basis.

2.1 Fundamental Derivation of Pipe Flow Equation

It is possible to derive a mathematical expression which describes fluid flow in a pipe by applying the principle of conservation of energy.

2.1.1 Principle of Conservation of Energy

The principle of the conservation of energy equates the energy of fluid entering, existing in and exiting from a control volume.

The energy equation can be written as:

$$\Delta\left[\begin{bmatrix}\text{Internal}\\\text{Energy of}\\\text{Fluid}\end{bmatrix} + \begin{bmatrix}\text{Energy of}\\\text{Expansion or}\\\text{Contraction}\end{bmatrix} + \begin{bmatrix}\text{Kinetic}\\\text{Energy}\end{bmatrix} + \begin{bmatrix}\text{Potential}\\\text{Energy}\end{bmatrix} + \begin{bmatrix}\text{Heat}\\\text{Added to}\\\text{System}\end{bmatrix} + \begin{bmatrix}\text{Work}\\\text{Done by}\\\text{System}\end{bmatrix}\right] = 0$$

ie

$$U_1 + p_1V_1 + \frac{mv_1^2}{2g_c} + \frac{mg \cdot h_1}{g_c} + Q - W_s = U_2 + p_2V_2 + \frac{mv_2^2}{2g_c} + \frac{mg \cdot h_2}{g_c} \qquad (51)$$

where U = internal energy
V = fluid volume
h = elevation above datum
Q = heat added or removed
m = mass of fluid
v = fluid velocity
p = pressure
W = work done or supplied

In differential form per unit mass:

$$dU + \frac{vdv}{g_c} + \frac{dP}{\rho} + \frac{g}{g_c} \cdot dh + dQ + dW = 0 \tag{52}$$

where ρ = fluid density

From thermodynamics, we can define the internal energy term as:

$$dU = dH - d\left(\frac{P}{\rho}\right) \tag{53}$$

where H = system enthalpy

$$dH = TdS + \frac{dP}{\rho} \tag{54}$$

where T = absolute temperature
S = entropy

Substituting for the internal energy in Equation 53 gives:

$$T \cdot dS + \frac{dP}{\rho} - d\left(\frac{P}{\rho}\right) + d\left(\frac{P}{\rho}\right) + \frac{vdv}{g_c} + \frac{g}{g_c}\, dh + dQ + dW = 0$$

i.e.

$$TdS + \frac{dP}{\rho} + \frac{vdv}{g_c} + \frac{g}{g_c} \cdot dh + dQ + dW = 0 \tag{55}$$

However, for an irreversible process, we can apply the Clausius inequality: ie.

$$dS \geq \frac{dQ}{T}$$

or

$$T \cdot dS = dQ + dE_w \tag{56}$$

where dE_w = energy losses due to irreversibilities

Assuming Equation 56 is valid and that dW = 0, we can obtain the general equation:

$$\frac{dP}{\rho} + \frac{vdv}{g_c} + \frac{g}{g_c}\ dh + dE_w = 0 \qquad (57)$$

Assuming that the pipe is inclined at angle θ to the vertical as shown in Figure 12:

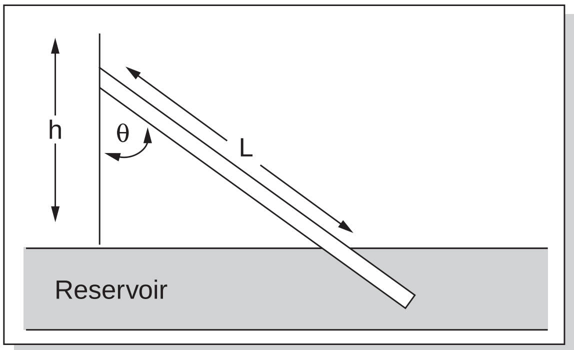


Figure 12
Deviated well orientation

$$dh = dL \cdot \cos\ \theta \qquad (58)$$

Therefore, by substitution into Equation 57 we obtain:

$$\frac{dP}{\rho} + \frac{vdv}{g_c} + \frac{g}{g_c}\ dL\ \cos\ \theta + dE_w = 0 \qquad (59)$$

Multiplying both sides of the equation by ρ / dL, we obtain:

$$\frac{dP}{dL} + \frac{\rho}{g_c} \cdot v \frac{dv}{dL} + \frac{g}{g_c} \cdot \rho \cdot\ \cos\theta + \rho \cdot \frac{dE_w}{dL} = 0 \qquad (60)$$

In terms of the pressure gradient, we can rewrite Equation 60:

$$\frac{dP}{dL} = \frac{\rho}{g_c} \cdot v \frac{dv}{dL} + \frac{g}{g_c} \rho \cos\theta + \rho \frac{dE_w}{dL} \qquad (61)$$

If we assume that the irreversible losses are due to friction:

$$\left(\frac{dP}{dL}\right)_f = \rho \frac{dE_w}{dL} \qquad (62)$$

where $(dP / dL)_f$ = pressure gradient due to viscous shear

Thus, Equation 62 becomes:

$$\frac{dP}{dL} = \frac{\rho}{g_c} v \cdot \frac{dv}{dL} + \frac{g}{g_c} \rho \cos\theta + \left(\frac{dP}{dL}\right)_f \qquad (63)$$

The three components of the pressure gradient in the above equation are:

(1) the change in potential energy

$$\frac{g}{g_c}\rho\cos\theta$$

(2) the change in kinetic energy

$$\frac{\rho}{g_c}v\frac{dv}{dL}$$

(3) the component due to frictional pressure loss

$$\left(\frac{dP}{dL}\right)_f$$

This equation defines the pressure loss for steady state, one dimensional flow.

2.1.2 The Friction Factor

The loss in fluid energy when fluid flows from will comprise:

(1) loss in fluid pressure

(2) loss in fluid potential if elevations of points 1 and 2 are different

(3) loss in energy due to shear stress at the pipe wall

Consider the case where no differential in fluid potential arises, ie, a horizontal pipe.

Applying a force balance:

$$(P_1 - P_2)\,dA = \tau_w\,(2\pi r)\cdot dL$$

where τ_w = shear at the pipe wall

$$P_1 \cdot dA - \tau_w \cdot 2\pi r \cdot dL = P_2\,dA \qquad (64)$$

or

$$\left(P_1 - P_2\right) \pi r^2 = \tau_w \cdot 2\pi r \cdot dL$$

$$\frac{\left(P_1 - P_2\right)}{dL} = \left(\frac{dP}{dL}\right)_f = \frac{2\tau_w}{r} \tag{65}$$

We can define the Fanning friction factor f as a measure of the shear characterics of the tubular wall:

$$f = \frac{\text{wall shear stress}}{\text{kinetic energy / volume}}$$

$$f = \frac{\tau_w}{\frac{1}{2}\rho\frac{v^2}{g_c}} \tag{66}$$

Substituting into Equation 65:

$$\left(\frac{dP}{dL}\right)_f = 2 \cdot \frac{1}{2}\ \rho\ f\frac{v^2}{g_c} \cdot \frac{1}{r} \tag{67}$$

$$= \rho \cdot f \cdot \frac{v^2}{g_c} \cdot \frac{1}{r} \tag{68}$$

or

$$\left(\frac{dP}{dL}\right)_f = 2 \cdot \frac{\rho\ f\ v^2}{g_c\ \cdot d} \tag{69}$$

where d = pipe inside diameter.

In terms of the Moody friction factor f_m defined as:

$$f_m = 4f \tag{70}$$

$$\left(\frac{dP}{dL}\right)_f = \frac{f_m\ \rho\ \ v^2}{2\ g_c\ d} \tag{71}$$

2.2 Single Phase Flow Characteristics

Single phase fluid flow in pipes can be defined in 2 major categories, namely:

- laminar flow where the individual streamlines are parallel to the bulk flow direction

- turbulent flow where the bulk flow is directed towards a location of lower energy but individual stream lines are in random directions, i.e., turbulence

The flow conditions will dictate which of these flow regimes exists but a transitional flow period will exist for flow conditions between the regimes. The transition from laminar to turbulent flow is shown in figure 13.

(1) Single Phase Laminar Flow

From the Hagen-Poisseuille Equation, we can obtain:

$$v = \frac{g_c \cdot d^2}{32\ \mu} \cdot \left(\frac{dP}{dL}\right)_f \qquad (72)$$

Equating Equations 61 and 62 for $\left(\frac{dP}{dL}\right)_f$, we obtain:

$$f_m = \frac{64\ \mu}{v\ \rho\ d} \qquad (73)$$

The Reynolds Number (N_{Re}) is a dimensionless group which characterises flow and the relationship between the main parameters.

$$N_{Re} = \frac{v\ \rho\ d}{\mu} \qquad (74)$$

Hence, from Equation 64:

$$f_m = \frac{64}{N_{Re}} \qquad (75)$$

or

$$N_{Re} = \frac{64}{f_m}$$

Thus, for laminar flow

$$\left(\frac{dP}{dL}\right)_f \propto v$$

(2) Single Phase Turbulent Flow

Turbulent flow is sensitive to the physical nature of the inner pipe wall, ie, the pipe roughness. The Moody friction factor fm will be characterised by a series of relationships depending on the value of N_{Re} and the pipe roughness. The friction factor relationship is discussed below with respect to smooth and rough wall pipe:

(a) Smooth Wall Pipe

The simplest equation is that of Drew, Koo and McAdams:

$$f_m = 0.0056 + 0.5\ N_{Re}^{-0.32} \quad (76)$$

This equation is valid for $3000 \leq N_{Re} \leq 3 \text{ x } 10^6$

The equation does not directly involve the pipe roughness.

(b) Rough Wall Pipe

The pipe wall roughness is highly variable and will depend upon

- the pipe material
- manufacturing method
- service condition

The absolute roughness of the pipe e is defined as the mean protruding height of relatively uniformly distributed and sized, tightly packed sand grains that would give the same pressure gradient behaviour as the actual pipe.

It has been suggested that the effect of roughness on frictional pressure loss is characterised better by the relative roughness, ie, e/d, the ratio of the absolute roughness to pipe inside diameter. Turbulent flow frictional pressure loss depends on the relative roughness but also on the thickness of the laminar sub-layer in contact with the pipe wall, which in itself depends on N_{Re}.

Various relationships have been proposed:

$$\frac{1}{\sqrt{f_m}} = 1.74 - 2\ \log_{10}\left(\frac{2\varepsilon}{d}\right) \quad (77)$$

after Nikuradse

and

$$\frac{1}{\sqrt{f_m}} = 1.74 - 2\ \log_{10}\left(\frac{2\varepsilon}{d} + \frac{18.7}{N_{Re}\sqrt{f}}\right) \quad (78)$$

after Colebrook

Moody has produced an alternative chart which attempts to indicate the relevant curves for various pipe grades and manufacturing processes. Figure 13.

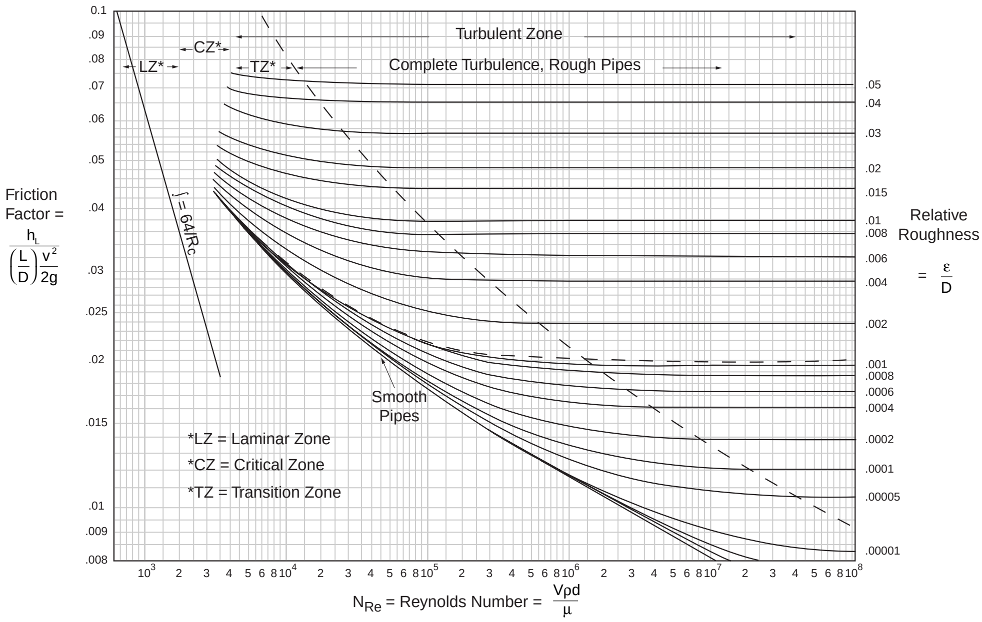


Figure 13
Friction factors for any type of commercial pipe

The frictional pressure gradient for single phase turbulent flow will still be a function of the velocity as in the case for laminar flow, but the proportionality will be more complex and a function of the relative roughness.

$$\left(\frac{dP}{dL}\right)_f \propto v^n$$

where $1.7 \leq n \leq 2.0$

The application of the generalised equation to a pipe flow situation will depend upon the characteristics of the fluid. It can be seen that the pressure gradient dP / dL is a function of:

velocity	v
density	ρ
wellbore or pipe inclination angle	θ
pipe diameter	d
friction factor	f_m
viscosity	μ

Some of the above parameters will be dependent on pressure and temperature in the wellbore to a greater or lesser extent. Fluid leaving the reservoir to flow up the well to surface will be at a high pressure and temperature. In flowing to surface, the fluid will:

(1) lose pressure in accordance with the general pressure loss expression

(2) lose heat to the surrounding formations and, as a result, its temperature will decline

Both these effects are depicted in Figure 14 although the exact shape of the resultant profile will depend on the fluid which is flowing.

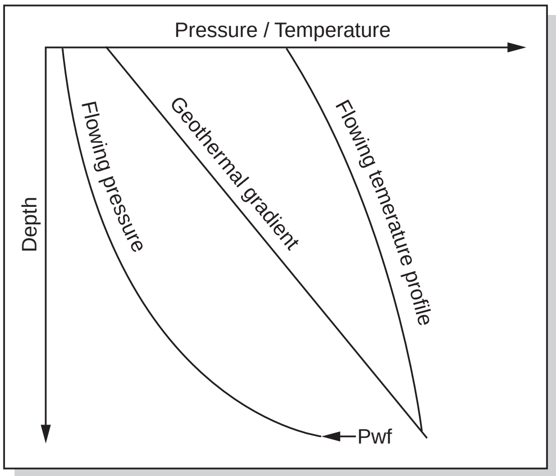


Figure 14
Temperature and pressure profile in a flowing oil / gas well.

2.2.1 Dry Gas Flow

(1) Effect of Pressure

Gas is a low viscosity, low density fluid which possesses a very high coefficient of isothermal compressibility, ie,

$C_g = 300 \times 10^{-6}$ vol / vol / psi

As the gas flows to surface, its pressure will decline and it will undergo the following changes:

(a) as a result of the high compressibility, the density will dramatically decline

(b) as the density declines, the potential energy or hydrostatic pressure gradient will decline proportionally.

(c) as the density declines, the gas will expand, resulting in a proportional increase in velocity.

(d) as the gas velocity increases, the frictional pressure gradient will increase according to the relationship.

For laminar flow:

$$\left(\frac{dP}{dL}\right)_f \infty \ v$$

and for turbulent flow:

$$\left(\frac{dP}{dL}\right)_f \propto v^n \text{ where } n = 1.7 - 2.0$$

For most gas production wells, the flow regime in the tubing will be transitional or turbulent depending on the individual well and completion. These effects are depicted in Figure 13.

The relative contribution of both the frictional and hydrostatic pressure gradients as a function of gas flowrate is illustrated in Figure15.

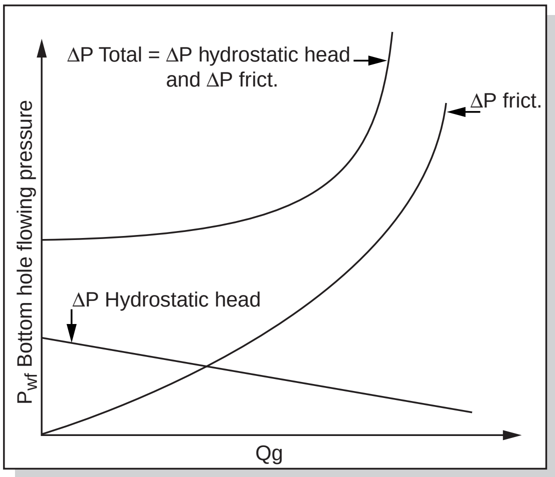


Figure 15
Single phase gas well - tubing pressure loss

(2) Effect of Temperature

For gas, the temperature profile may not exhibit a significant decline (cooling), since the gas will naturally possess a low convective heat transfer coefficient. Extremely high gas velocities in the tubing may significantly increase the heat transfer coefficient but, because of the high mass flowrate, a substantial increase in the degree of cooling may not be seen. Localised cooling due to gas expansion may introduce significant anomalies in the profile.

2.2.2 Single Phase Liquid Flow - Oil or Water

(1) Effect of Pressure

In general, crude oil can be classified as slightly compressible, the degree of compressibility being dependent on the crude oil gravity - a light crude oil with an API gravity of, say, 35˚ would be more compressible than a heavier crude oil with an API gravity of 20˚ API. A typical oil compressibility (C_o) would be 8 - 12 x 10^{-6} vol / vol / psi. Water is even less compressible and is frequently considered to be incompressible (C_w = 6 - 8 x 10^{-6} vol / vol / psi).

For the flow up tubing of a single phase liquid, the following will occur:

(a) As the liquid flows upwards, the density will decline by the order of 0.5 - 1.0

% for every 1000 psi drop in pressure, ie, the rate of density decline is minimal and the resultant effect on the hydrostatic or potential energy gradient will be negligible.

(b) As pressure declines, the viscosity will decrease slightly.

Hence, for oil or water, the impact of flow on the physical properties of the fluid will be negligible and hence the increase in frictional gradient will remain almost constant, as shown in Figure 16.

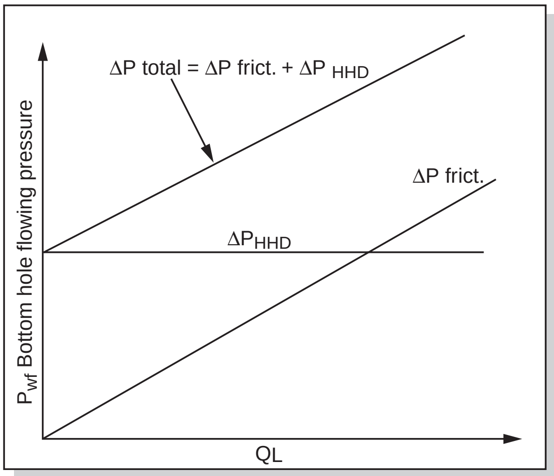


Figure 16
Incompressible liquid flow in the tubing.

(2) Temperature Effects

The convective heat transfer coefficients for oil and water will be higher than for gas but the lower extent of turbulence will offset the heat transfer. In general, compared to a gas well, the flowing temperature profile will indicate substantial cooling. In an oilwell, the progressive cooling will serve to:

(a) increase liquid density opposing the decrease in density associated with the reducing flowing pressure. The effect on the velocity and hydrostatic pressure gradient will be self-evident.

(b) increase the liquid viscosity again opposing the decrease generated by reducing the pressure with depth.

The overall impact on the total pressure gradient will depend on the effects generated by declining flowing pressure and temperature as a function of depth.

2.3 Multiphase Flow Concepts in Vertical and Inclined Wells

It is clear from Section 2 that the behaviour of gas in tubing strings is markedly different. It would therefore be expected that the flow of a gas-liquid mixture would be more complex than for single phase flow.

2.3.1 Flow Characteristics in Vertical Wells

Each of the phases, both gaseous and liquid, have individual properties such as density and viscosity which will be a function of pressure and temperature and hence position in the well.

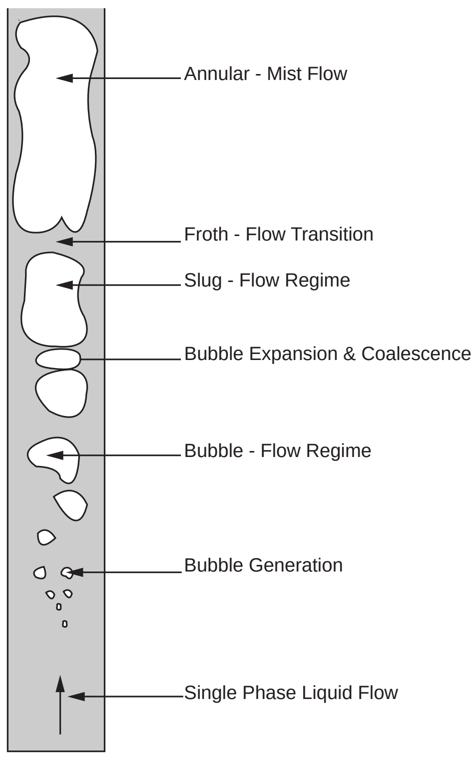


Figure 16 a Multiphase flow up the tubing

(1) Gas-Liquid Mixtures

In the production of a reservoir containing oil and gas in solution, it is preferable to maintain the flowing bottom hole pressure above the bubble point so that single phase oil flows through the reservoir pore space.

Consider such a case where oil flowing from the reservoir enters the production tubing. The flow of oil up the tubing and the associated pressure profile is illustrated in Figure 16 a. The oil may enter the tubing at a flowing pressure above the bubble point where no separate gas phase exists. The changing nature of the flow up the tubing can be considered in various stages from the base of the tubing:

(a) single phase liquid will occur in the tubing assuming the pressure is below the bubble point pressure. The pressure gradient is primarily influenced by the density of the liquid phase and is thus dominated by the hydrostatic head component of the pressure loss. Liquid expansion may contribute to a very slight reduction in liquid density and thence the hydrostatic gradient.

(b) At the bubble point, the first gas is evolved which will:

(i) lower the average density of the fluids in the tubing

(ii) increase the in-situ velocity

The gas is present in the form of discrete bubbles dispersed within the continuous oil phase. The flow regime is termed "bubble flow" and the pressure gradient will decline provided the decrease in hydrostatic head pressure loss exceeds the increase in frictional pressure loss.

(c) With continued upwards flow, the pressure on the fluid declines. The decline in pressure on the fluid will cause:

(i) expansion of the liquid phase

(ii) evolution of additional gas components - increasingly heavier molecules - resulting in an increased mass of hydrocarbon in the gas phase. A simultaneous reduction of the mass of the liquid phase will accompany this mass transfer. The concentration of heavier components in both the gas and liquid phases would increase.

(iii) expansion of the existing gas phase.

This section of the tubing would demonstrate a continuously declining pressure gradient provided the decrease in the hydrostatic component exceeds the increase in frictional gradient.

The above mechanisms will continue to occur continuously as flow occurs up the tubing.

(d) As flow continues higher up the tubing, the number and size of gas bubbles will increase until such a point that the fraction of the tubing volume occupied by gas is so large that it leads to bubble coalescence. The coalescence of bubbles will yield a "slug flow" regime characterised by the upward rise, due to buoyancy, of slugs of gas segregated by continuous liquid columns. The upwards movement of the slugs will act as a major mechanism to lift oil to surface.

(e) Often, as velocity continues to increase in the slug flow regime, it may be possible that a froth type transitional flow occurs where both the oil and gas phases are mutually dispersed, ie, neither is continuous.

(f) With continued upward movement, further gas expansion and liberation will occur, resulting in slug expansion and coalescence, leading to slug enlargement and eventually "annular flow". In annular flow, the gas flows up the centre of the tubing with oil flow occurring as a continuous film on the inside wall of the tubing.

(g) At extremely high velocities of the central gas column, shear at the gas-oil interface can lead to oil dispersion in the gas in the form of a "mist". This "mist flow" pattern will occur at very high flow velocities in the tubing and for systems with a high gas-oil ratio GOR.

It is possible that, as flow nears the surface, the increase in frictional pressure gradient exceeds the reduction in hydrostatic pressure gradient and, in such cases, the total pressure gradient in the tubing may start to increase.

These flow patterns have been observed by a number of investigators who have conducted experiments with air-water mixtures in visual flow columns.

The conventional manner of depicting the experimental data from these observations is to correlate the liquid and gas velocity parameters against the physical description of the flow pattern observed. Such presentations of data are referred to as flow pattern maps. An example is shown in Figure 17.

The map is a log-log plot of the superficial velocities of the gas and liquid phases.

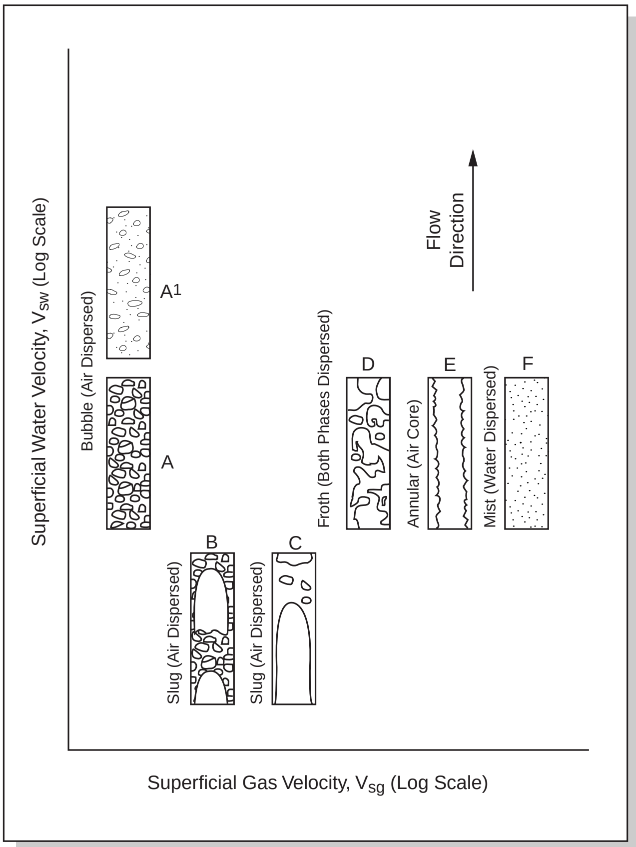


Figure 17
Flow pattern map for a gas / water mixture

(2) Liquid-Liquid Flow

The case of liquid-liquid flow in production wells may occur in low GOR wells which produce water. Since both phases are only slightly compressible or incompressible, it would be expected that the physical nature of the flow of an oil-water mixture to surface would not be as dramatically different from single phase liquid flow as the oil-gas system.

If oil and water enter the wellbore from the reservoir and flow up the tubing to surface, the physical distribution of the phases will depend upon their relative volumetric properties, ie, one phase will be continuous and the other dispersed. For example

(a) in a high WOR well (say, 90%), the oil would be dispersed in the continuous water phase.

(b) at a low WOR, the oil would be continuous.

Unlike the gas, because of the low compressibilities of oil and water, there will be little relative volumetric expansion between the two phases. Thus, the physical distribution will be more dependent on the WOR and the flow velocity as shown in Figure 18.

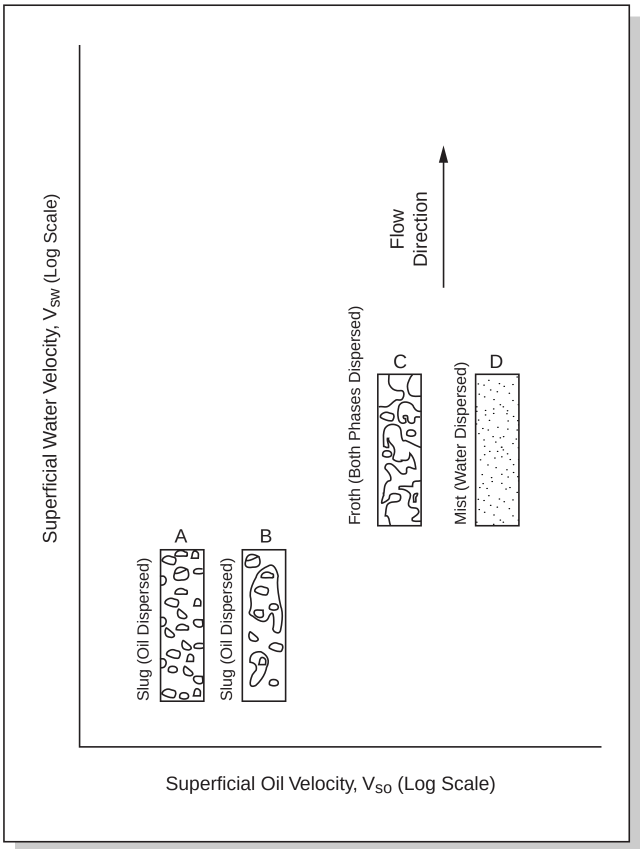


Figure 18
Flow pattern map for a water / oil mixture

(3) Flow Characteristics for Hydrocarbon Reservoir Fluids Systems

The physical flow processes discussed above will define the production of most hydrocarbon fluids.

(a) Dry Gas

Since no liquid phase will be present under any pressure conditions, the flow will be monophasic.

(b) Wet Gas

A wet reservoir gas will have small quantities of gas associated with it. As the gas flows to surface, the pressure will decline to the dewpoint, where the first liquid droplets will appear and be transported as a mist of particles in a continuous gas phase. Subsequent liquid deposition will emerge as mist.

(c) Gas Condensate

Gas condensate will contain a larger volume of liquid phase than the wet gas. At low liquid concentration at the dewpoint, the liquid phase could be present as a mist and as an “annular film” or subsequently a “slug” at higher concentrations. However, as flow continues up the tubing, the gas will expand dramatically and any liquid will transfer from

slug $\rightarrow$ annular film $\rightarrow$ mist

The above flow phenomena may be particularly exacerbated if the fluid is a retrograde condensate where liquid dropout in the tubing may revaporise as it flows up the tubing and the pressure declines.

(d) Volatile Oil

A volatile oil is characterised by a high GOR and thus as it flows to surface it may pass through all of the flow patterns discussed in section 1 above, including the single phase regime if $P_{wf} > P_{BPt}$, where P_{BPt} is the bubble point pressure. The range of patterns developed will depend on the flow velocity and the GOR.

(e) Black Oil

A black oil has a very low GOR and accordingly is unlikely to progress beyond the bubble and slug flow regimes into annular flow.

(f) Heavy Oil

Heavy oil normally has a very low (or nonexistent) GOR and as such it will vary from single phase oil to the bubble flow regime.

2.3.2 Multiphase Flow Characteristics in Inclined Wells

The increased application for drilling wells at various angles to the true vertical has been marked, particularly over the 1970s and 1980s, with offshore exploration and production moving into more costly operating areas. The impact on multiphase flow will be to:

(1) promote increased segregation between the phases, since the impact of density difference (buoyancy) will lead to migration of the lighter phase towards the upper part of the pipe cross-section.

(2) The hydrostatic head pressure component will depend upon the vertical depth of the portion being considered and not the length of tubing to that depth. In the derivation of the generalised pipe pressure loss equation, the pressure gradient due to potential energy will utilise the length of hole L, multiplied by cos θ, where θ is the angle of the borehole to the vertical.

(3) The frictional pressure gradient will be based on the alonghole length of the tubing as this defines the area for shear stress between the pipe inner wall and the fluid. Clearly the along hole length will exceed the true vertical depth.

The trend towards the increased application of horizontal wells is of importance. Many investigators have studied the flow of air water mixtures in pipes. As in the case of vertical pipe studies, the results can be presented in the form of flow pattern maps. In the horizontal section of the well, the hydrostatic gradient would be zero and most of the pressure loss attributable to frictional gradients.

Compared to vertical wells, it would be expected that:

(1) The bubble and slug flow regimes would be modified to account for the effects of buoyancy on the liquid phase, ie, the bubbles and slugs would tend to flow in the upper part of the pipe cross-section.

(2) The expansion of the gas slugs in the upper cross-sectional region of the pipe would lead to a stratified type flow where gas flows in the upper part and liquid in the lower part.

(3) With increasing gas flowrate, the gas would exert increasing drag on the liquid surface, resulting in "wave" flow.

(4) At even higher flowrates, the liquid phase may be distributed as an annular film or eventually as a mist within the continuous gas phase.

These flow patterns are depicted in Figure 19.

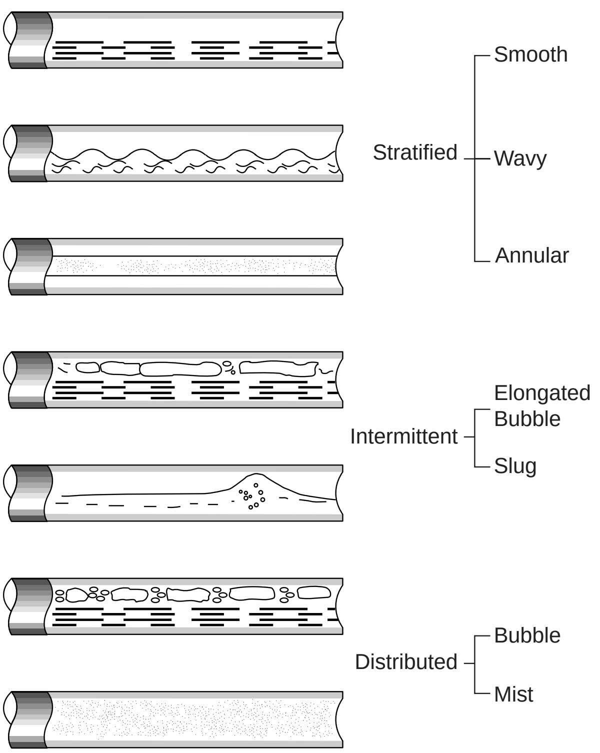


Figure 19
Flow patterns in a horizontal pipe

Inclined wells would exhibit the characteristics of either vertical or horizontal wells or a combination of both depending on hole angle. It should, however, be remembered that the profile of a deviated well of, say, 60˚ will demonstrate a inclination angle which will vary from 60˚ to 0˚ as we approach surface.

2.3.3 Fluid Parameters in Multiphase Flow

In calculating the pressure loss for single phase flow, fluid properties can be evaluated at any prescribed pressure and temperature. However, when evaluating the pressure gradient in multiphase flow, values for the various parameters must first be derived which are representative of the multiphase mixture. The properties of a multiphase mixture can normally be evaluated by combining the individual properties of the phases.

Important parameters which will influence the properties of a multiphase flow system are slippage and holdup.

1 Slippage

If a gas-liquid mixture flows up a tubing string, the effects of buoyancy on each of the phases will not be equal. The lighter of the phases, primarily gas, will rise upwards at an incrementally higher rate compared to the oil due to the effects of buoyancy.

The slip velocity, Vs, is defined as the difference in velocities of the two phases, ie, for a gas-oil system.

$$v_s = v_g - v_o \tag{79}$$

Particularly in the flow slug regime, the impact of slippage is to assist in lifting the heavier phase (oil) from the well. However if slippage is severe it can promote segregated flow particularly in the low velocity bubble flow regime

2 Holdup

Holdup is a term used to define the volumetric ratio between two phases which occupy a specified volume or length of pipe.

The liquid holdup for a gas-liquid mixture flowing in a pipe is referred to as H_L:

$$H_L = \frac{\text{Volume of liquid in a pipe segment}}{\text{volume of pipe segment}} \tag{80}$$

H_L therefore has a value between zero and one.

Similarly, the gas holdup Hg is defined as:

$$H_g = \frac{\text{Volume of gas in a pipe segment}}{\text{volume of pipe segment}} \tag{81}$$

Obviously,

$$H_L + H_g = 1.0 \tag{82}$$

3 Fluid Velocity

A difficulty arises as to how to define the velocity of a specific phase. There are two options:

(a) The first option is to define velocity based upon the total cross-sectional area of the pipe despite the fact that each phase will occupy a fraction of the area. The velocity in this case is termed the ***superficial velocity.***

For gas:

$$v_{sg} = \frac{q_g}{A} \tag{83}$$

where A = cross-sectional area of the pipe
and for liquid:

$$v_{SL} = \frac{q_L}{A} \tag{84}$$

(b) A more accurate value for the velocity of each phase is to correct for the holdup of each phase.

The actual gas velocity:

$$v_g = \frac{q_g}{A \cdot H_g} \tag{85}$$

2.4 Single Phase Flow Performance Predictions

The prediction of tubing pressure loss is reasonably simple for situations where a single phase is flowing up the tubing. The derived general equation for pressure loss from the principle of the conservation of energy can be applied:

$$\frac{dP}{dL} = \frac{\rho}{g_c}\frac{vdv}{dL} + \frac{g}{g_c}\,\rho \cos\theta + \frac{f_m \cdot \rho\, v^2}{2g_c\, d} \tag{86}$$

In most cases, the pressure gradient associated with kinetic energy changes is very small and usually ignored. Hence:

$$\frac{dP}{dL} = \frac{g}{g_c} \cdot \rho \cos\theta + \frac{f_m \cdot \rho\, v^2}{2g_c\, d} \tag{87}$$

2.4.1 Single Phase Liquid Flow

In most production or injection wells, the liquid phase will be incompressible, ie, water, or slightly incompressible, eg, oil. The pressure drop in the tubing can be predicted by applying the general energy equation and ignoring the kinetic energy (acceleration) losses:

$$\therefore \left(\frac{dP}{dL}\right)_{Total} = \left(\frac{dP}{dL}\right)_{fric} + \left(\frac{dP}{dL}\right)_{PE} \tag{88}$$

These pressure loss components can be evaluated.

For a vertical well:

$$dP = \frac{\rho g}{g_c}\ D_{TVD} + \frac{\rho\ f_m\ v^2}{2g_c \cdot d} \cdot D_{TVD} \tag{89}$$

with f_m being the friction factor evaluated for laminar or turbulent flow.

For an inclined well, the potential energy item will be based upon as appropriate the true vertical depth D_{TVD} but the frictional item on the along hole depth D_{AH}, ie:

$$dP = \rho\ D_{TVD} + \frac{\rho\ f_m\ v^2}{2g_c \cdot d} \cdot D_{AH} \tag{90}$$

The application of this equation can be applied sequentially to each section of the tubing string to yield a cumulative pressure loss.

2.5 Multiphase Flow Models

Many investigators have conducted research into multiphase flow in tubing. Most of the investigative approaches have made basic assumptions which can be used to classify the correlations derived as follows:

(1) Methods which do not consider

(a) slippage between phases

(b) the use of flow regime or pattern

(2) Methods which consider slippage between the phases but not flow regimes.

(3) Methods which consider both flow regime and slippage.

Most of the multiphase flow correlations can be used with the following general procedure:

(1) Use will be made of the general equation:

$$\left(\frac{dP}{dD}\right)_{TOTAL} = \left(\frac{dP}{dD}\right)_{elev} + \left(\frac{dP}{dD}\right)_{frict} + \left(\frac{dP}{dD}\right)_{accel}$$

(2) Determine:

$$\left(\frac{dP}{dD}\right)_{elev} = \bar{\rho}_m$$

This may or may not require the evaluation of holdup depending on the correlation used.

(3) Calculate:

$$\left(\frac{dP}{dD}\right)_{frict} = \frac{f_m \ \rho_m \ v_m^2}{2g_c \ d}$$

Each method will have its own approach to determine fm but it may be dependent on flow pattern.

(4) Calculate:

$$\left(\frac{dP}{dD}\right)_{accel} = \frac{\rho_m \ \Delta\left(v_m^2\right)}{2g_c \ dD}$$

2.5.1 Correlations which consider neither Slippage nor Flow Regimes

The methods in this category include:

- Poettmann and Carpenter
- Baxendell and Thomas
- Tek
- Fancher and Brown
- Hagedorn and Brown

With these methods, slippage is not considered nor are the various flow regimes which exist in multiphase flow. The methods are based on a fluid density calculated from the density of the surface fluids and corrected for downhole conditions. The methods are based on their individual approach or correlations for calculating the two phase friction factor. The friction factor is correlated against the numerator of the Reynold's number, ie, (ρ , v , d).

2.5.2 Correlations which include Phase Slippage but not Flow Pattern

In these methods, correlations are necessary to allow prediction of both the slippage and the friction factor. However, since the methods do not distinguish between flow regimes, the correlations are assumed to be valid for all flow regimes. The concept of slippage will require that the superficial velocities of the phases be calculated and the volumetric pipe fraction for each phase is used to define the mixture properties.

Hagedorn and Brown conducted experiments in small diameter tubings 1" - $2^1/_2$" and included in their correlation the effects of kinetic energy loss, considered to be significant in small diameter tubings.

2.5.3 Correlations which consider both Slippage and Flow Regime

The bulk of the research reported in multiphase flow lies within this category, including:

- Duns and Ros
- Orkiszewski
- Aziz, Govier and Fogerasi
- Beggs and Brill

All the above, propose a method of predicting the slippage or holdup based upon the assumed set of flow regimes. The methods therefore widely use flow pattern maps. Prediction of the flowing pressure loss requires correct identification of the flow regime which prevails in the tubing. Some of the investigators proposed new correlations for all the flow regimes whilst others suggested modifications to existing correlations for one or more of the flow regimes.

2.6 Correlations for Inclined Wells

The inclination of the drilled well will introduce the following changes in the pressure gradient:

(1) The frictional pressure gradient will increase as the along hole depth increases compared to the true vertical depth.

(2) The increased frictional pressure loss will change the overall pressure gradient on the well and hence the fluid properties which will influence the hydrostatic gradient.

There are two approaches to evaluating the pressure loss in an inclined well, namely:

(1) Use a vertical well correlation and modify the frictional gradient term to account for along hole depth instead of true vertical depth, ie, $D_{TV} \cdot \cos\theta$ where θ is the hole angle to the vertical.

(2) Use a modified inclined well correlation. e.g. Beggs and Brill

2.6.1 Use of Vertical Well Pressure Loss Correlations

Any of the correlations discussed above can be used by modifying the frictional and hydrostatic gradient term as suggested above. The use of the correlation in this way assumes, however, that:

(1) the holdup correlation developed for vertical wells will be valid for inclined wells

(2) the physical distribution of the phases and flow regimes will remain the same.

Beggs and Brill found that these assumptions were not necessarily valid.

It can therefore be concluded that the use of such adjustments to vertical multiphase correlations will be of limited accuracy.

2.6.2 Inclined Flow Correlations

Relatively little research has been conducted in this area, with the majority of techniques evolving from horizontal correlations modified to account for uphill sections of pipeline.

Amongst the published methods are the following:

- Beggs and Brill

- Griffith et al

The Griffith et al correlation only considered two flow regimes, namely slug flow and annular flow. It did not consider the effects of pipe roughness, liquid viscosity and entrainment.

The method of Beggs and Brill is a widely accepted method for predicting inclined well pressure drop.

There are major difficulties associated with developing a general inclined well flow correlation including:

(1) the inclination in the well will not be constant

(2) the well may suffer from doglegging, which will impact on well slugging

2.7 Gradient Curves

Gilbert was the first to introduce the concept of a pressure gradient curve. The gradient curve provides a plot of pressure variations with depth in a tubing string for a range of specified flow conditions and as such provides a simplified but less accurate approach to predicting tubing performance using a multiphase flow correlation.
Gilbert obtained data in the form of pressure traverses upon a range of oil production wells and the data was plotted with respect to the following parameters:

- GOR or GLR

- tubing diameter
- liquid or oil production rate

His data was restricted to 1.66", 1.9", 23/8", 27/8" and 31/2"; for flowrates of 50, 100, 200, 400 and 600 BPD. Therefore, for constant values of the above parameters, a range of curves were obtained by plotting the data, each curve reflecting a different tubing head pressure, as shown in Figure 20. The implication of this was that a specific gradient curve would be required for each tubing head pressure to be considered

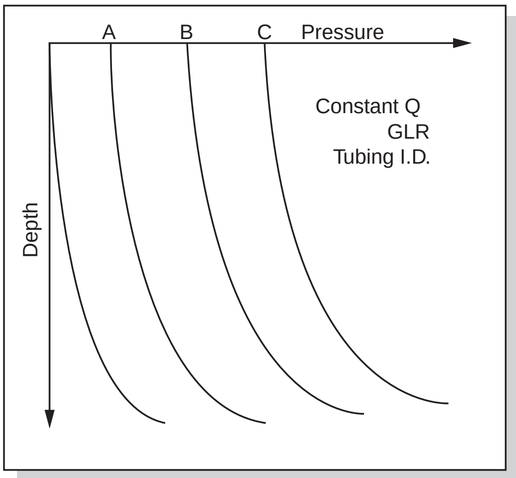


Figure 20 Gilberts Representation of Well Traverses as P versus depth

However, by shifting the curves downwards, he found that, for a constant GLR, flowrate and tubing size, the curves overlapped, as depicted in Figure 21. Then, a single curve could be utilised to represent flow in the tubing under assumed conditions. This curve could be constructed to pass through the point of zero pressure at surface. The impact of moving the individual curves down until they overlapped was in effect to extend the depth of the well by a length which, if added to the top of the tubing, would dissipate the tubing head pressure and result in zero pressure at the top.

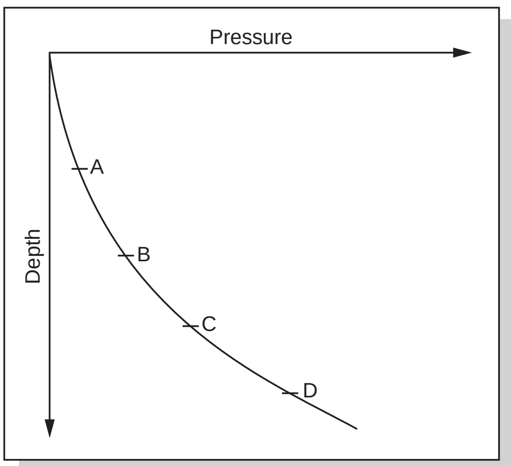


Figure 21 Standardisation of Gilberts Curves

Gilbert was then able to collect all the curves for a constant tubing size and flowrate together on the one graph, resulting in a series of gradient curves which would accommodate a variety of GLRs, eg, Figure 22. He was then able to prepare a series of gradient curves which apply for a constant liquid production rate and tubing size.

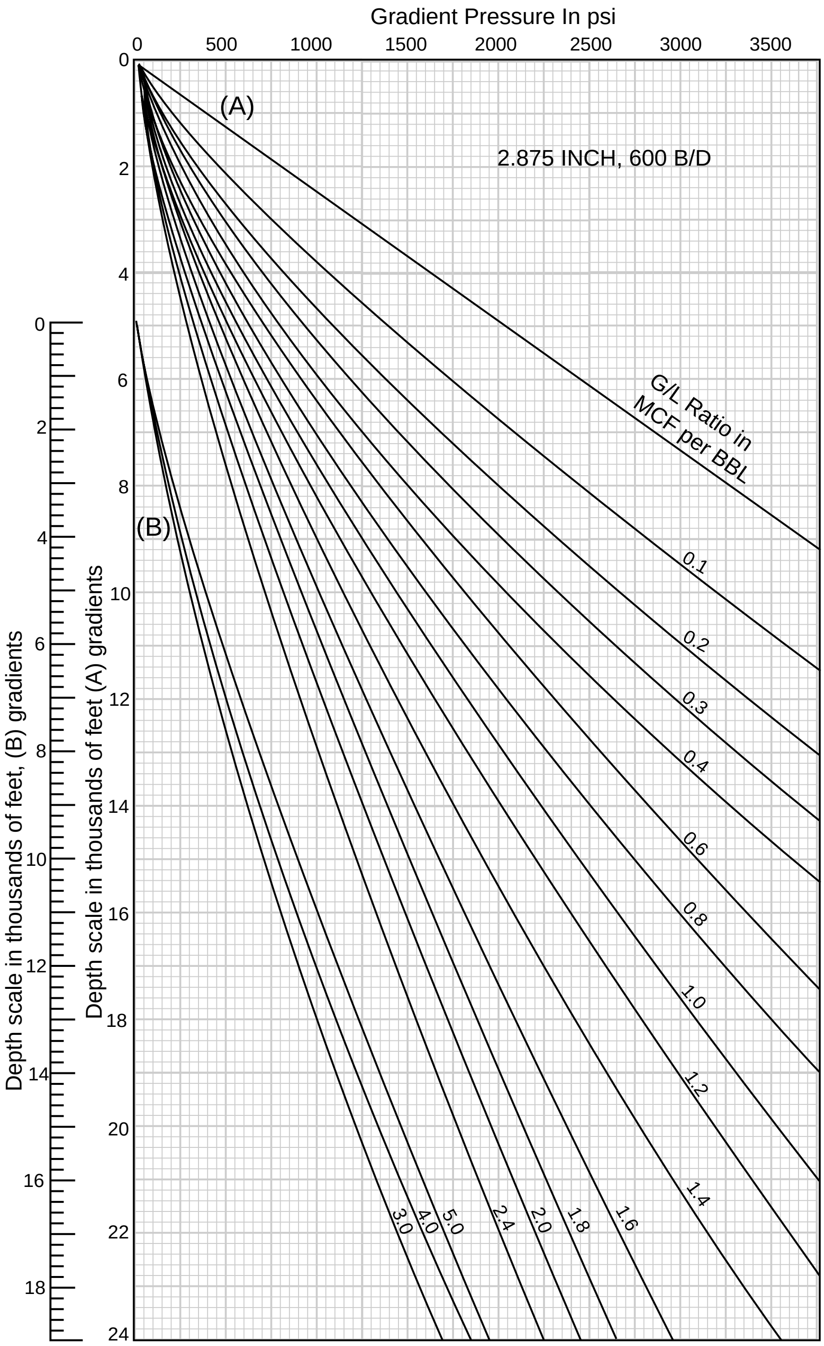


Figure 22
Approximate depth - pressure gradients for 2.875 - in. tubing

The method of using these curves to predict bottomhole pressure is (Refer Figure 23):

Given:
Well Depth
Tubing Size
GLR
Production Rate
Tubing Diameter

Calculate required THP

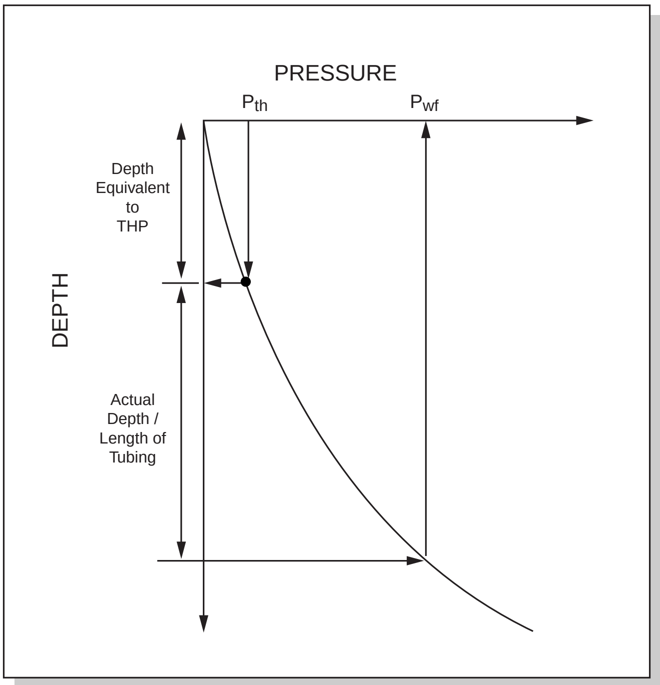


Figure 23 Bottomhole Flowing Pressure Prediction

(1) From the appropriate gradient curve for the specific GLR, Qo and tubing diameter, calculate the depth or length of tubing equivalent to the tubing head pressure Pth.

(2) Add the depth equivalent to the Pth to the actual depth of the well to obtain the total equivalent depth.

(3) Entering the curve with the total equivalent depth and from the intersection with the gradient curve read off the equivalent pressure which is the bottomhole hole flowing pressure.

The gradient curves exhibit several interesting features:

(1) It can be seen that the slope of the curves or pressure gradient is a function of depth. This reflects the effects of phase expansion and slippage.

(2) As the GLR increases, the gradient declines. This reflects the reduction in the hydrostatic head.

(3) Some of the curves will demonstrate turnover or reversal at very high GLR. This indicates the curves passing through the minimum pressure gradient and the subsequent increase in gradient at a specific depth as frictional losses dominate over the reduction in hydrostatic head due to increase in GOR.

Gradient curves in themselves are merely a method of representing tubing pressure data and can be developed using field measurements or from the application of any of the pressure loss correlation discussed previously.The main advantage of gradient curves is their speed and simplicity but they are clearly not as accurate as numerical correlations. The original curves of Gilbert were restricted to flowrate and tubing sizes less than 600 BPD and $3^{1/2}$" respectively. However, using published correlations, families of curves can be developed for any tubing size, flowrate and for various water cuts. Curves can also be developed using the Beggs and Brill approach for inclined wells; however, the validity of these will depend upon the trajectory and curvature of a specific wellbore.

2.8 Optimisation of Tubing Flow

Gilbert was one of the first investigators to attempt to explain the complexities of tubing flow performance and its optimisation.

The impact of tubing size on tubing pressure loss for gas flow is dictated primarily by the frictional pressure loss. However, for oil and gas flow in production tubing, it would be expected that for a specific flowrate and GLR there would be two opposing effects, namely:

(1) For small tubing size, in situ flow velocities would be high, thus increasing the frictional pressure loss.

(2) For large tubing sizes, the average upwards velocity would be small enough for the buoyancy forces on the lighter phase, and hence slippage, to be significant. This would result in a higher pressure gradient.

Gilbert illustrated the effects of tubing size and GLR on the optimisation of tubing performance.

2.8.1 Effects of GLR

Gilbert presented data on the impact of GLR on the flowing bottomhole pressure requirements in the form of Figure 24 and 25. This illustrated that the impact of increasing the GLR on the tubing pressure loss was:

(1) To reduce the hydrostatic gradient of the fluid in the tubing, the hydrostatic gradient would approach that of the gas as its volume fraction approached unity.

(2) At high liquid rates, the total volume of gas will be so high that the pressure gradient will increase, reflecting the rise in the frictional pressure gradient.

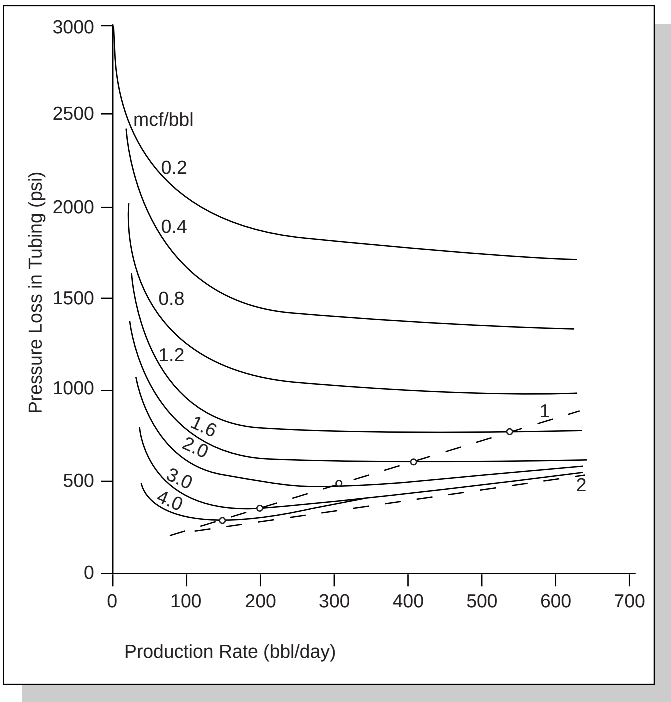


Figure 24
Pressure Loss as a Function of Production Rate at Various Gas/Liquid Ratios (Gilbert)

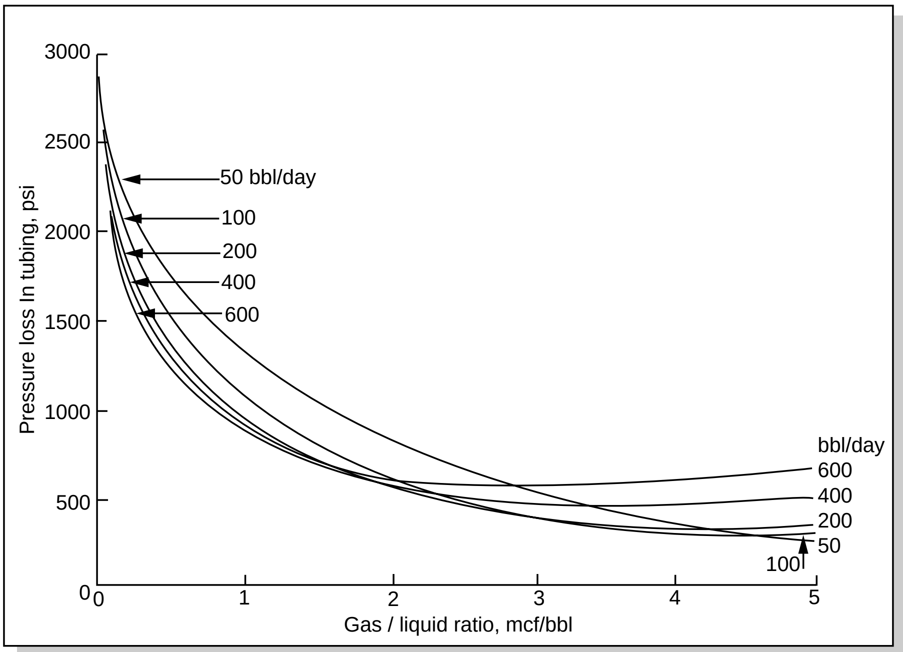


Figure 25
Pressure loss as a function of gas / liquid ratio at various production rates (Gilbert)

Thus, a minimum pressure gradient will exist. The GLR corresponding to the minimum total pressure gradient will increase as production rate declines, reflecting the impact of phase velocities in the tubing (Figure 24).

2.8.2 Effects of Tubing Size

In the discussion of the effects of GLR above, it is clear that the controlling influence of phase velocities and the potential for slippage is significant.

Gilbert presented data in relation to his field-derived pressure gradient measurements. These are shown in Figures 26 - 29 for GLRs of 400 and 1000 SCF/bbl.
In Figure 26, the low production rate of 50-100 BPD results in higher pressure requirements in the larger diameter tubings, $2^{7/8}$" / $3^{1/2}$", due to phase separation and slippage. At these flowrates, in the smaller tubings, eg, $2^{3/8}$" diameter and less pressure gradients are lower and the flow is more efficient. At the higher rate of 200 BPD or more, it is possible that the smaller tubing sizes will require higher lift pressures, ie, the smaller tubing sizes exhibit friction pressure increases whilst the larger tubing sizes benefit from reduced slippage between the phases. The smaller tubing sizes of 1.66" - $2^{3/8}$" exhibit a minimum pressure requirement at an intermediate flowrate.

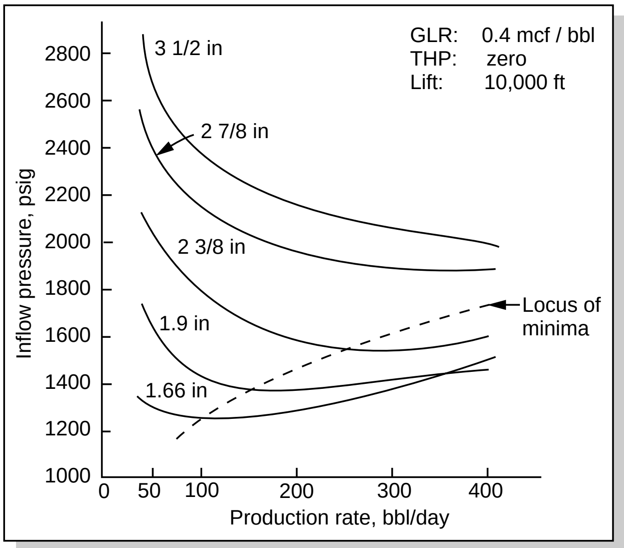


Figure 26
Effect of flow rate on vertical flow pressure losses: various tubing sizes. Low GLR. (Gilbert)

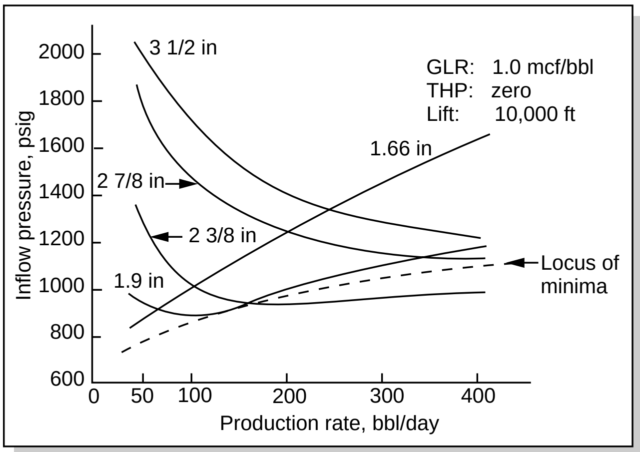


Figure 27
Effect of flow rate on vertical flow pressure losses: various tubing sizes. High GLR. (Gilbert)

The higher GLR case of 1000 SCF / BBL is illustrated in Figure 27 but there are a number of changes compared to the 400 SCF / bbl case in Figure 26:

(1) Overall, all tubing sizes require a lower flowing bottom hole pressure in the low production case with 1000 SCF / bbl compared to the 400 SCF / bbl, ie, reduced slippage because of the higher in situ tubing velocities due to the higher gas flowrate.

(2) For all tubing sizes except the 1.66", the minimum FBHP is achieved in the 1000 SCF / bbl case compared to the 400 SCF / bbl.

(3) For the 1.66" tubing, the gas flowrate is too high, even at very low production rates. The FBHP does not pass through a minimum at a GLR of 1000 SCF/bbl and the FBHP increases continuously with increasing production rate as a result of the high frictional gradients.

The data is alternatively presented in Figures 28 and 29. The data for the 1000 SCF / bbl clearly shows a minimum pressure loss associated with flowrates of 100 bbl / d or more. The tubing size which provides the minimum intake pressure, increases with increasing flowrate.

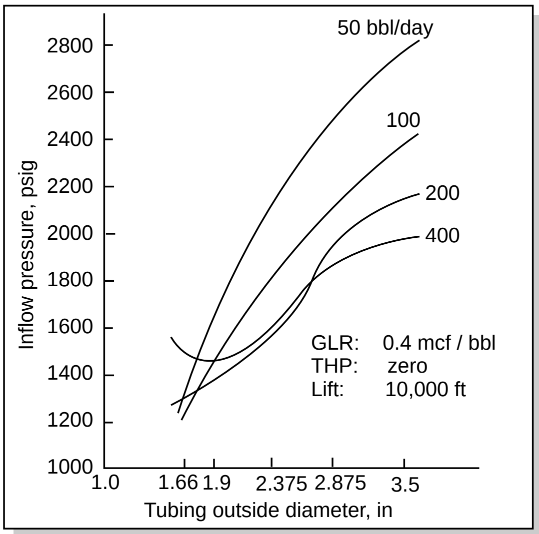


Figure 28 Effect of tubing size on vertical flow pressure losses: various flow rates (Gilbert)

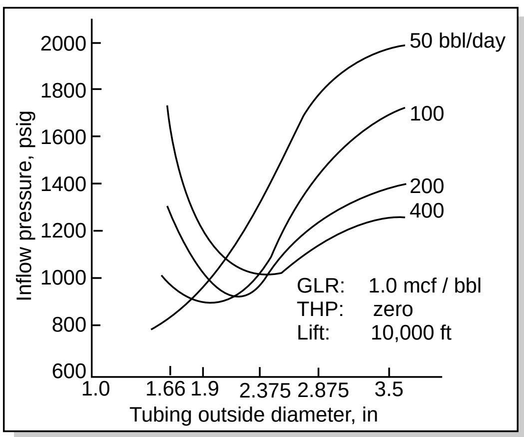


Figure 29 Effect of tubing size on vertical flow pressure losses: various flow rates

It is noticeable that for the 400 SCF / bbl in Figure 28, increasing tubing size requires a higher FBHP for low to moderate flow rates 50 - 200 BPD.

These results from Gilbert help to highlight the opposing effects of slippage and excessively high frictional pressure drop.

2.8.3 The Effects of Water-Oil Ratio

The impact of produced water with the oil is to increase the mixture density thus promoting increased slippage and increased hydrostatic head. This is shown in Figure 31 which can be compared with the 0% water cut in Figure 30. It can be seen that the effect of slippage is perhaps more pronounced in the case of the 7" tubing with a 25% water cut. However, in general for all the tubing sizes, FBHP is increased where 25% water cut exists, particularly in the small tubing sizes and for the high rate-large tubing diameter cases (about 10-20%).

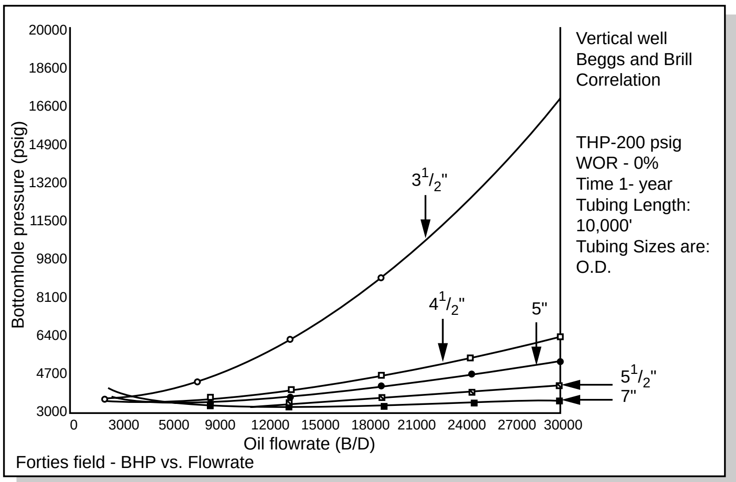


Figure 30
BHP vs flowrate for a high rate well - 0.1% water cut

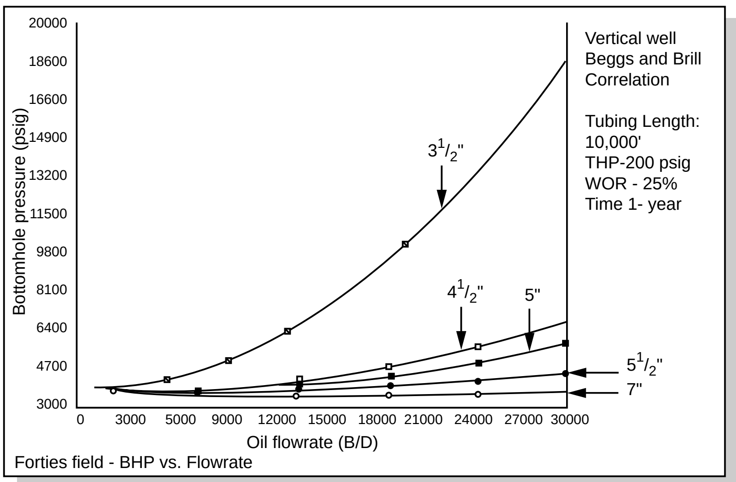


Figure 31
BHP vs flowrate for a - 25% water cut

3. FLOWLINE CHOKES

In this section, the function and operating characteristics of chokes installed in production flowline will be discussed.

3.1 Functions of Flowline Chokes

The fluid pressure within the reservoir provides the driving force to push fluid into the wellbore and, in natural flow wells, up the production tubing to the surface. To maximise the production capacity of individual wells, it is possible to ensure that minimal restriction exists in the flowline. However, in such cases, the production capacity of the system will be continually adjusting itself in line with any flow perturbation or instabilities in the well. Thus, most production wells utilise a choke or restriction in the flowline downstream of the wellhead to back pressure the well.

The implementation of flowline back pressure close to the wellhead may be important for some of the following reasons:

(1) To maintain stable flow/pressure conditions downstream of the choke

(2) To control the drawdown on the well and hence restrict the occurrence of gas cusping or water coning into the wellbore or the failure of the formation around the wellbore

(3) To dampen down fluctuations in the well deliverability by applying back pressure to the system

(4) To isolate the well from pressure fluctuations created in the processing, gathering and transportation system

The choke therefore plays an important role in:

(1) well control

(2) reservoir depletion management

3.2 Choke Equipment

Chokes are designed to restrict or throttle flow and as such several different designs have been developed. The choke creates the flow restriction by offering a restricted flow path for the fluid to pass through. This restriction can be selected to be:

- fixed

whereby the orifice size is specified before installation

- adjustable

whereby the orifice size can be adjusted after installation to suit the well and operational requirements

The design of the orifice can fall into any one of three categories, namely:

(1) a retrievable cylindrical duct of fixed internal bore - fixed or positive choke

(2) a valve stem and seat which can be adjusted to control the effective orifice size

(3) twin tungsten carbide discs with flow ports which have adjustable alignment

Positive chokes are particularly useful where the fixed orifice is essential for monitoring well performance, eg, during well tests. The pressure drop across the choke depends upon the fluid characteristics, the flowrate and choke dimensions.

An adjustable choke allows the back pressure on the well to be varied. This may be useful in the following instances:

(1) when initiating production on a well, in which the tubing contents have to be displaced out of the well by inflow from the reservoir. In this case, the FBHP will decline and hence the production rate increases continuously during this period, thus necessitating the application of gradually increasing back pressure.

(2) to control a well on cyclical production, or where frequent changes in production rate are necessary.

(3) on wells which are frequently subject to shutdown.

3.2.1 Positive or Fixed Choke

This normally consists of two parts:

(1) A choke which consists of a machined housing into which the orifice capability or "bean" is installed.

(2) A "bean" which consists of a short length 1-6", of thick walled tube with a smooth, machined bore of specified size.

The assembly is shown in Figure 32.

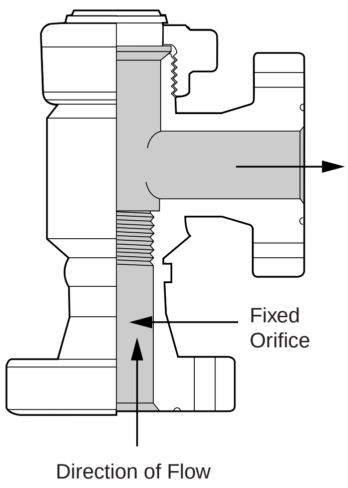


Figure 32
Fixed choke

The term positive refers to the fact that, upon installation, the choke is of a fixed and known dimension. However, with production, the choke dimension, particularly if located at surface and/or in a gas well, will change due to hydraulic and particulate erosion.

Fixed chokes are occasionally installed in wireline nipples at depth in the tubing string in certain wells to:

(1) Reduce the tubing head pressure and operating pressures on the Xmas tree and wellhead

(2) Counteract the effects of hydrates and wax deposition associated with fluid expansion and cooling. The location of cooling is moved down into the tubing string where the fluid can extract heat from the surrounding formation as it flows to surface.

3.2.2 Valve Seat with Adjustable Valve Stem

In this design, the choke is normally located on a 90˚ bend. The orifice consists of a valve seat into which a valve stem can be inserted and retracted, thus adjusting the orifice size.

The movement of the valve stem can either be manual as shown in Figure 33 or automatic using an hydraulic or electrohydraulic controller.

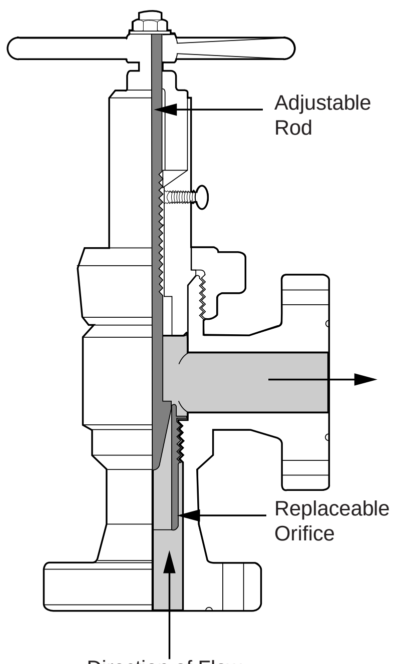


Figure 33
Adjustable choke

3.2.3 Rotating Disc Choke

This type of adjustable choke is illustrated in Figure 34. It consists of a 90˚ flanged bend which can be coupled up to the flowline or Xmas tree. Internally, there are two discs made from tungsten carbide, ceramic or other erosion-resistant material. Both discs have two ports which are diametrically opposite in each disc. The rear disc is fixed whilst the front disc located on top of it can be rotated through a maximum of 90˚ via a fork, externally controlled manually or remotely. The ports can be of a circular or of a range of alternative shapes.

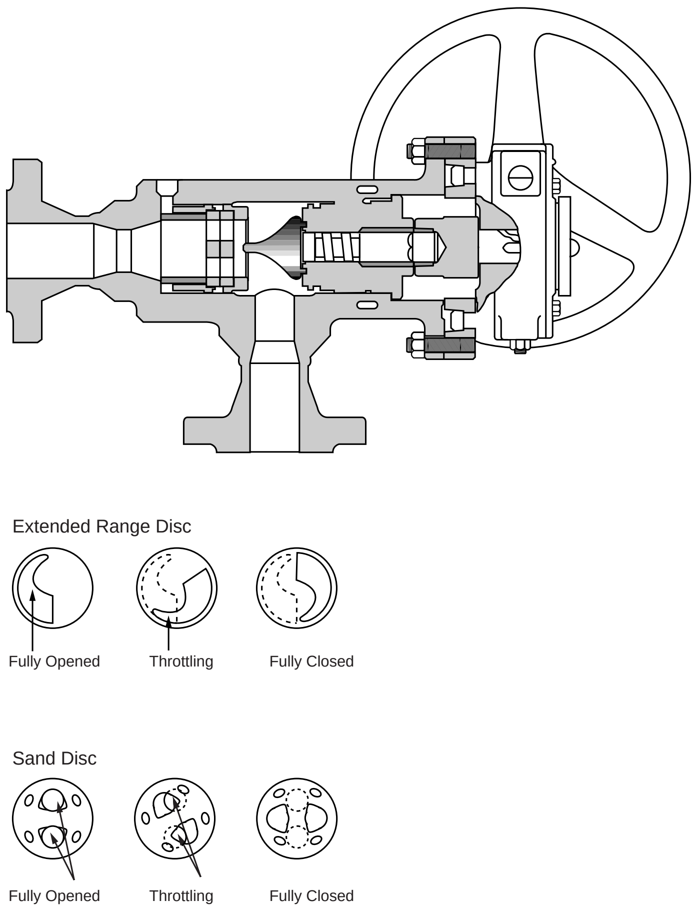


Figure 34
Rotating disc adjustable choke

This type of choke is considered to provide more accurate gradual flow control than the other systems.

3.3 Choke Flow Characteristics

Production chokes normally operate in a multiphase environment, ie, gas in liquid or liquid in gas flow. Single phase can occur in dry gas wells. Theoretical models exist for predicting the performance of chokes with single phase fluids. It is likely that the flow will be strongly influenced by the choke geometry or configuration as well as multiphase flow.

3.3.1 Flow Behaviour and Distribution

However, if we consider flow through a square edged or rounded orifice, the use of a fixed choke will present a reduced orifice of some considerable length. The flow through such a choke is depicted in Figure 35.

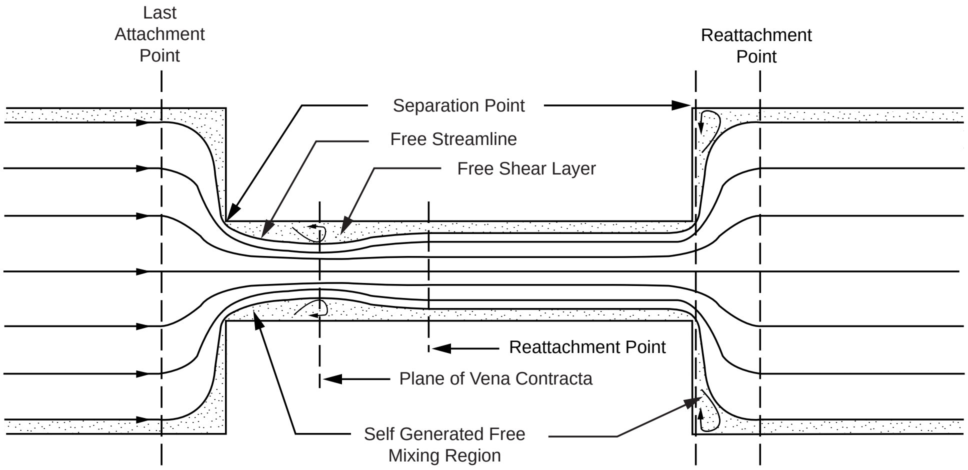


Figure 35
Choke flow model

The flow through the choke depicted in Figure 35 occurs in various progressive stages:

(1) The flow system of the choke will normally be in equilibrium up to a short distance from the entrance to the choke.

(2) As the flow approaches the inlet to the choke, it is accelerated and other flow adjacent to the pipe wall derives a high radially inward velocity which is considered to be of comparable magnitude to the axial velocity.

(3) At the inlet, the flow separates and the high radially inward velocity causes the jet to contract and to continue to accelerate downstream of the inlet, forming the vena contracta.

(4) At the vena contracta, the separated jet causes some entrainment of the fluid from the recirculation vortex formed between the jet and the wall. This is caused by the high shear stresses between the jet and the fluid in the separation vortex.

(5) The entrainment causes deceleration of the jet which expands to fill the entire cross-section of the choke.

(6) On exit from the choke, the fluid expands to fill the pipe cross-section.

It should be noted that eddy mixing currents occur in the region of fluid entry and exit from the nozzle as well as around the vena contracta.

Irreversible pressure loss across the choke occurs, due to:

(1) frictional loss through the choke

(2) turbulence effects associated with the eddy currents at the entrance and exit of the choke

(3) fluid expansion or exit from the choke

(4) localised turbulence/eddying within the choke itself, particularly at the vena contracta.

3.3.2 Critical Flow through Chokes

Consider the case of a controlled increase in the flowrate through a fixed choke, accomplished by opening a control valve downstream of the choke.

Initially, with the valve closed, the pressure is equal both upstream and downstream of the choke. As the valve is gradually opened, the downstream pressure P_2 declines and the flowrate increases. If the valve continues to be opened, the flowrate will start to level off and ultimately reach a plateau as depicted in Figure 36. Further decrease in P_2 will not produce any increase in production rate.

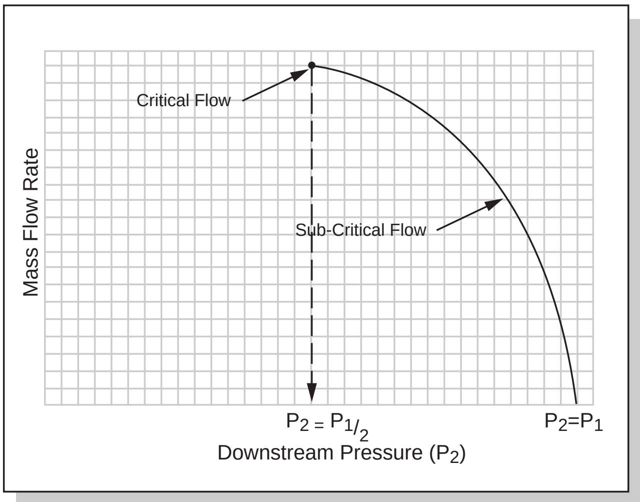


Figure 36
Downstream pressure control

The ratio of upstream to downstream pressure is termed R:

$$R = \frac{P_2}{P_1}$$

where R = pressure ratio
P_2 = downstream pressure
P_1 = upstream pressure

The value of R at the point where the plateau production rate is achieved is termed the critical pressure ratio Rc.

Flow at pressure before the plateau production rate is achieved is termed sub-critical flow and, once plateau conditions are achieved, the flow is classed as critical flow. Critical flow behaviour is only exhibited by highly compressible fluid such as gases and gas/liquid mixtures.

For gas, which is a highly compressible fluid, the critical downstream pressure Pc is achieved when velocity through the vena contracta equals the sonic velocity, i.e., this means that a disturbance in pressure or flow downstream of the choke must travel at greater than the speed of sound to influence upstream flow conditions. In general, critical flow conditions will exist when

$R_C \leq 0.5$

For a two-phase compressible mixture, say, oil and gas, the sonic velocity in such fluids will generally be lower than that for a gas system. In general, for critical flow conditions:

$R_C \leq 0.5$ - 0.6 depending on the system

Guzor and Medviediev investigated the effect of the degree of fluid compressibility in terms of the gas volume fraction on the critical pressure ratio. Their results are shown in Figure 37 and correlate the pressure ratio with the mixture velocity through the choke for various gas volumetric fractions. The division between critical and sub-critical flow is clearly seen.

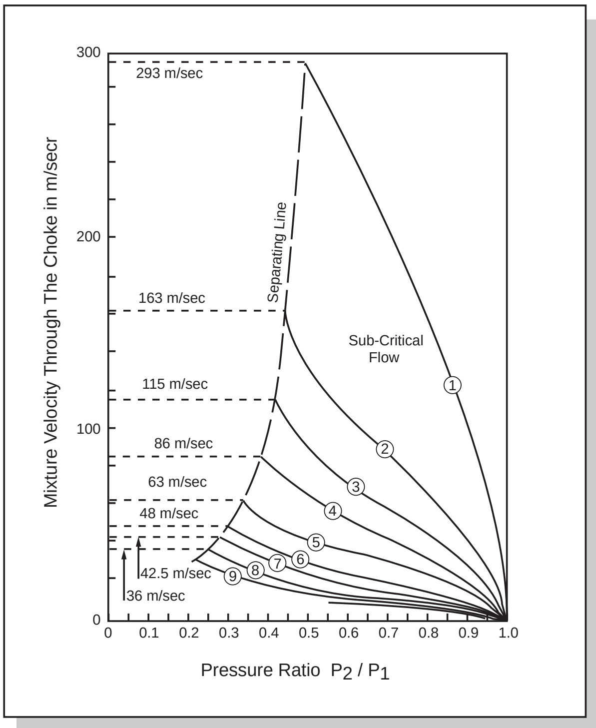


Figure 37
Velocity of gas/oil mixtures through chokes

3.4 CHOKE FLOW CORRELATIONS

Flow through the choke will be largely influenced by whether single or multiphase flow occurs.

3.4.1 Single Phase Flow

The rate of flow through an orifice q, if the velocity of approach is neglected, is expressed as:

$$q = C_d \ A \ \sqrt{2g_c \cdot h_L} \tag{92}$$

where C_d = discharge coefficient
A = cross-sectional area of the orifice
h_L = loss of pressure head across the orifice

3.4.2 Multiphase Flow through a Choke

A number of researchers have published studies on multiphase flow through chokes. Some of the studies relate to correlation of field measurements.

Assuming a knife edged circular orifice and making several simplifying assumptions with regard to the phase properties, it can be shown theoretically that:

$$P_{TH} = \frac{C_d\, R^{\frac{1}{2}}\, Q}{S^2} \qquad (93)$$

where P_{TH} = tubing head flowing pressure in psia
C_d = constant (about 100)
R = gas liquid ratio (MSCF/bbl)
Q = gas liquid ratio (STB/d)
S = bean size in 1/64"

Several fluid empirical choke performance formulae based on field or experimental data have been proposed, of the form:

$$P_{TH} = M \cdot \frac{q^a\, R^b}{(A)^c} \qquad (94)$$

R = gas liquid ratio
q = liquid flowrate
A = cross-sectional area of the choke

a, b, c and M are constants

The value of the constants will depend upon

- the choke characteristics and dimensions
- the gas and liquid properties
- the flowing temperature at the choke

The majority of the correlations assume critical flow across the choke.

(1) Gilbert's choke correlation

In 1954, Gilbert proposed the following empirical relationship based on field data:

$$P_{TH} = \frac{465\ R^{0.546} \cdot q}{S^{1.89}} \tag{95}$$

where P_{TH} = flowing tubing head pressure in psig.

He also presented the information as a nomograph (Figure 38). The nomograph is split into 2 portions. The left hand side related the production rate and GLR and the right had side utilised a 10/64" choke for reference and this is related to choke size and P_{TH}.

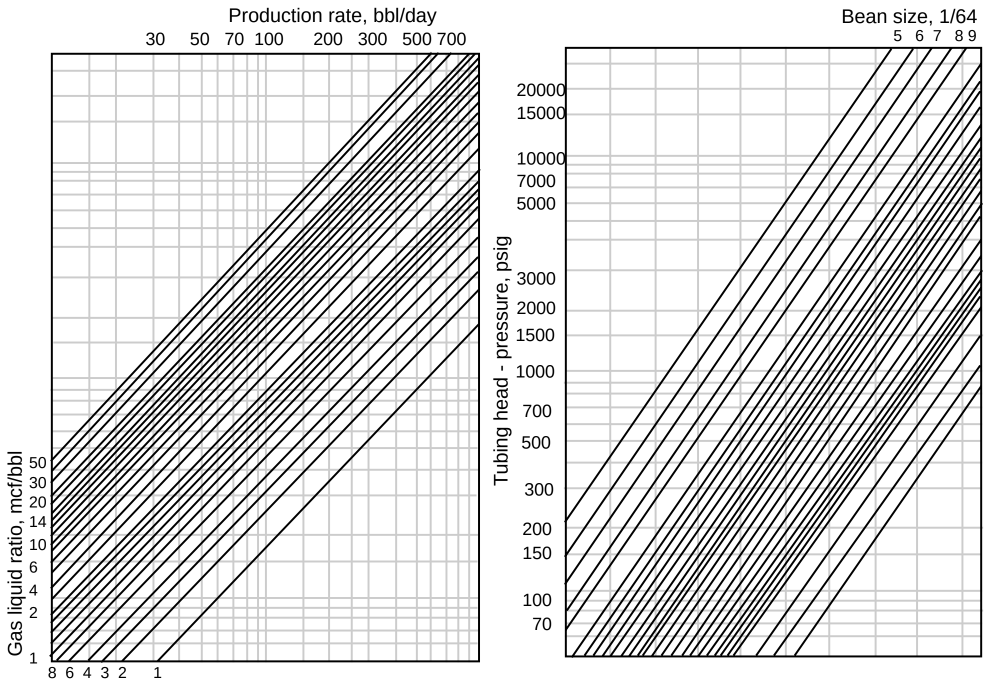


Figure 38
Gilbert's bean performance correlation

(2) Achong choke correlation

Achong proposed a modified version of the Gilbert choke performance equation, based on field data from Venezuela. The correlation is:

$$P_{TH} = \frac{3.82\ R^{0.65} \cdot q}{S^{1.88}} \tag{96}$$

where P_{TH} = psig and R = GLR in SCF/bbl.

A nomograph was developed by Achong as provided in Figure 39.

The nomograph uses a pivot or tie line to predict choke sizes.

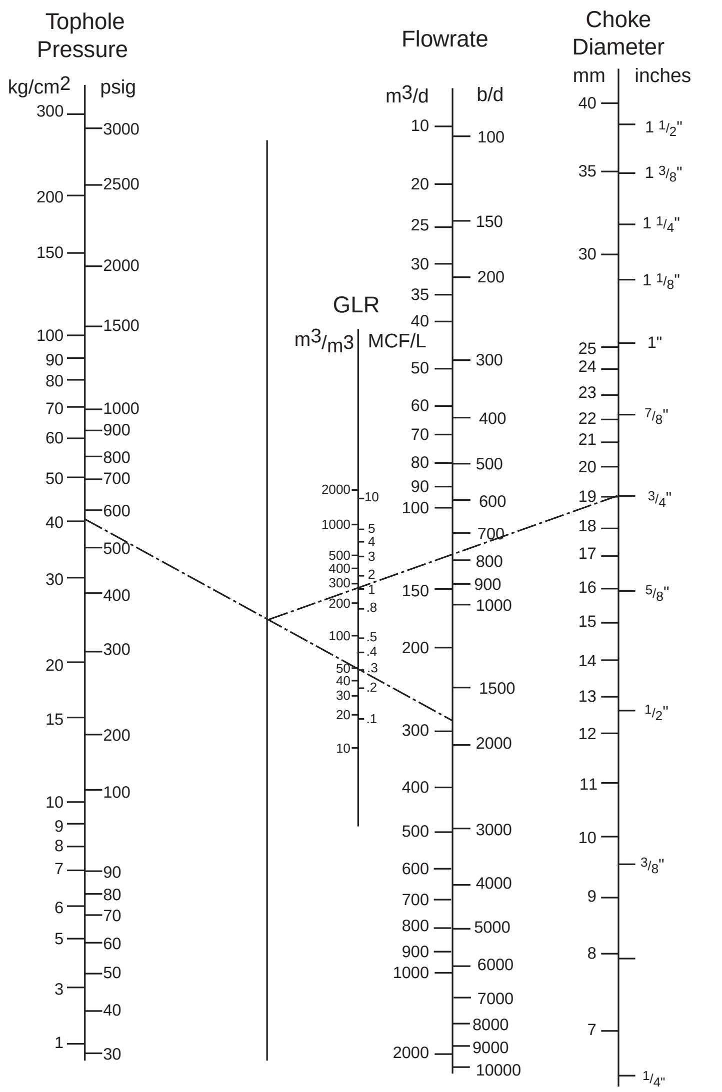


Figure 39
Bean performance chart
(after Achong)

4. COMPLETION FLOW PERFORMANCE AND OPTIMISATION

In the previous three section of this chapter, we have looked at sequentially:

(1) inflow performance or pressure loss

(2) tubing flow performance and pressure loss

(3) choke pressure loss.

In Chapter 2, the dissipation of reservoir pressure was discussed and stated in simplified form as:

$$P_R = \Delta P_{RES} + \Delta P_{TUB} + \Delta P_{CHOKE} + \Delta P_{FLOWLINE} + P_{SEP} \tag{97}$$

Where

P_R = Reservoir Pressure (initial or average)

ΔP_{RES} = Pressure Drop across the Reservoir

ΔP_{TUB} = Pressure Drop along Tubing

ΔP_{CHOKE} = Pressure Drop across Choke

$\Delta P_{FLOWLINE}$ = Pressure Drop in Surface Flowline and Fittings

P_{SEP} = Operating Pressure Required in the Separator

$P_R = [\Delta P_{SYSTEM}]_q + P_{SEP}$

ie

$$P_R = [\Delta P_{RES}]_q + [\Delta P_{TUB}]_q + [\Delta P_{CHOKE}]_q + [\Delta P_{FLOWLINE}]_q + P_{SEP} \qquad (98)$$

Since the pressure loss in the system is flowrate dependent, the production rate from the well can be optimised.

4.1 Matching the Inflow and Tubing Performance

In Equation 98, each of the component pressure drops is identified as being flowrate dependent. There are various methods of predicting the performance of a flowing well system, each of which can be graphically represented. For simplicity, the case of oil production will be considered.

(1) Method 1 - Reservoir and tubing pressure loss convergence in predicting bottomhole flowing pressure

In this simplified technique, the approach will be to predict the bottomhole flowing pressure, P_{wf}, from both directions, i.e. converge on predicting P_{wf} from:

(a) from the separator back up the flowline and down the tubing to the formation

and

(b) from the reservoir pressure P_R or P_e assuming inflow inwards to the wellbore

Since both of these pressure losses are rate dependent, we seek to identify the operating flow rate at which reservoir pressure is fully utilised to maximise the production rate for an assigned tubing head or separator pressure.

The calculation of the pressure losses and the identification of the operating flowrate is easily obtained from a plot of bottomhole flowing pressure versus production rate, with P_{wf} being calculated based on reservoir and tubing pressure loss respectively.

The method is depicted in Fig 39 and comprises the following stages:

(a) Predict P_{wf} as a function of inflow flowrate q from the reservoir using either

(i) the straight line assumption, the productivity index and reservoir static or average pressure

(ii) a radial inflow performance equation

(iii) Vogel’s technique or a variant thereof

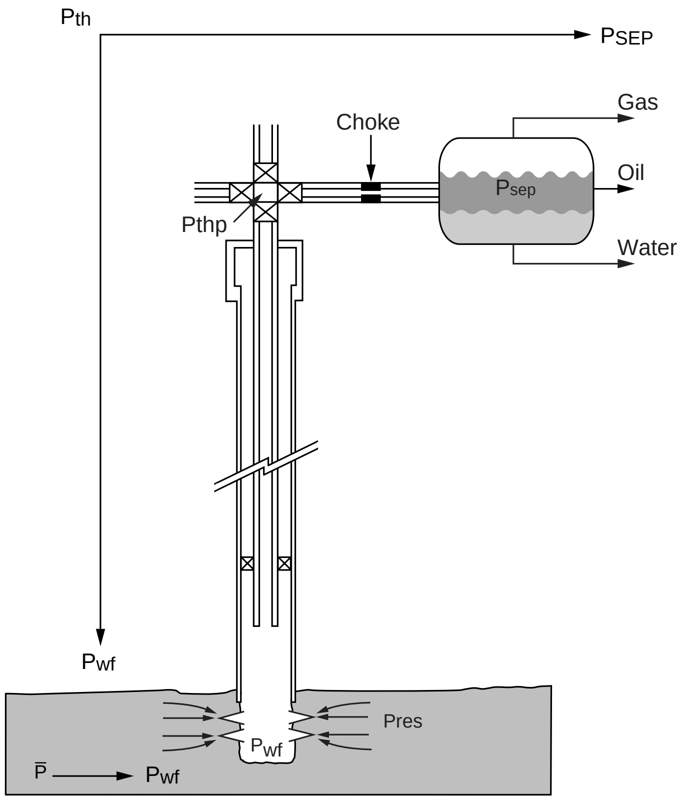


Figure 39
Simplified approach to evaluating bottomhole flowing pressure

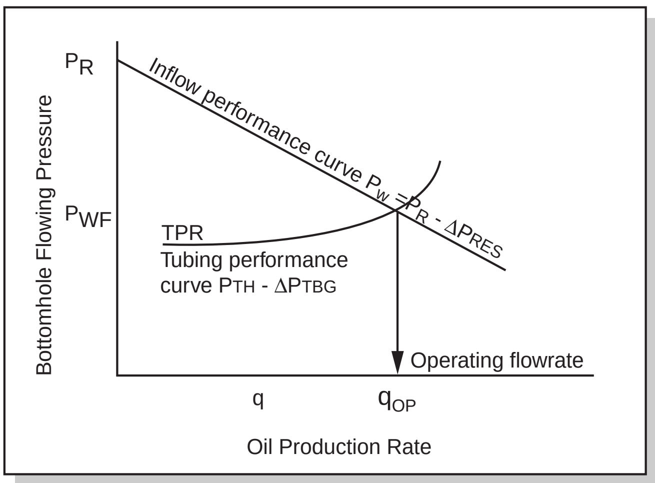


Figure 40
Evaluation of the operating flowrate

(b) Predict P_{wf} from pressure loss in the tubing using either.

Using P_{TH}, the tubing size and length, the flowing gas liquid ratio, we use a series of gradient curves for individual flowrate, to back calculate the flowing bottomhole pressure as a function of rate based upon.

(i) the specified tubing head pressure

or

(ii) Predict tubing head pressure as [2x P_{SEP} + ΔP flow]

We can then plot P_{wf} versus q, based on tubing pressure loss requirements.

(c) At the point of intersection as shown in figure 41, the bottomhole flowing pressure required based on both the IPR at that rate, and the tubing performance at that same flowrate, are equal.The flowrate at the intersection of the two curves is termed the operating flowrate.

(2) Method 2 - cumulative pressure loss from reservoir to separator

In this method, the basis of pressure availability will be the inflow performance relationship. This method differs from Method 1 in that the tubing head pressure will be calculated as a function of flowrate. Using the respective P_{wf} calculated by inflow performance as the start point for calculating the tubing pressure loss from the gradient curves and read off the residual tubing head pressure. The procedure is as follows:

(a) Calculate P_{wf} as a function of flowrate using the PI or inflow performance relationship. Plot P_{wf} versus q.

(b) Assume a range of flowrates q. For each flowrate estimate the available Pwf from the graph. Using this value of P_{wf}, locate this pressure on the relevant gradient curve. Move up the curve a depth equivalent to the actual vertical depth of the well. Read the pressure at this point. The pressure will correspond to P_{TH} for that particular flowrate.

Plot P_{TH} versus q. Repeat over the range of flowrates.

(c) Calculate P_{Th} requirements based on choke performance. Repeat for a range of choke sizes if the choke size (S) was not previously specified. Plot the choke performance line.

(d) The interaction between the actual choke performance P_{TH} specified as required and the predicted P_{TH} based on the IPR/TPR, provide the operating flowrate for the well using that choke size (Figure 42).

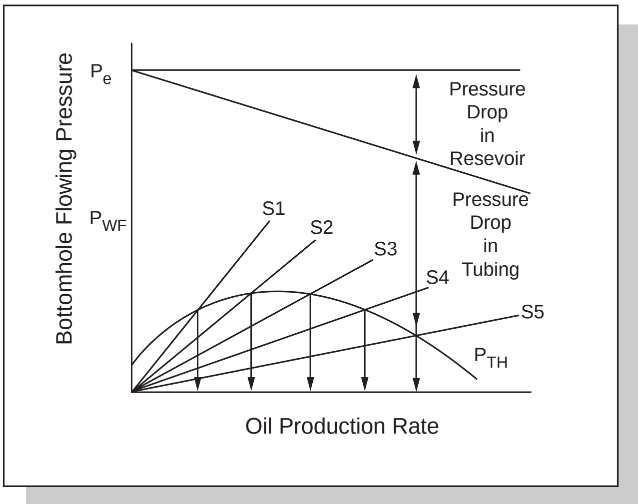


Figure 42
Operating flowrates for various choke sizes

The above techniques allow the prediction of the flow performance for a well utilising the following information:

IPR or PI relationship

tubing size(s)and configuration

tubing length or well depth

GLR and water cut.

The above procedures can also be adapted to consider the case where the flowline pressure loss is significant. Based on a separator pressure required downstream of flowline, the rate dependent pressure loss in the flowline can be evaluated leading to a modified tubing head pressure requirement. Having established a revised tubing head pressure requirement, we can then use Method 1 or 2 to evaluate the flow capacity for various tubing sizes. Figure 43.

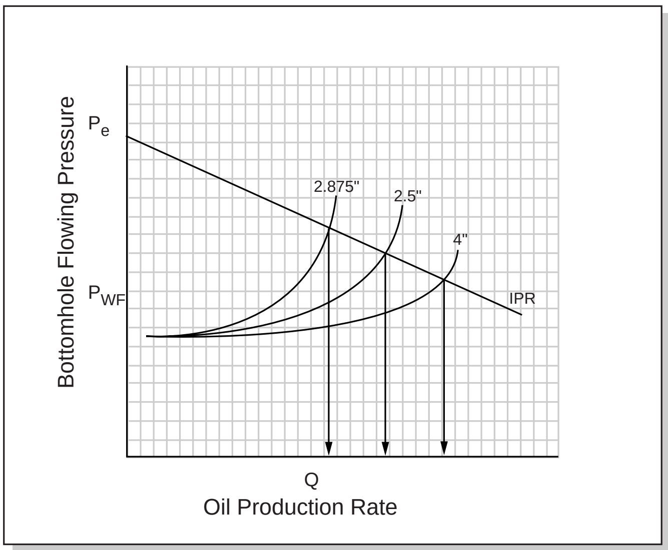


Figure 43
Tubing sizing with method one

SUMMARY

In this chapter we have reviewed the basic principle of wells producing by natural flow.

Our starting point was reservoir pressure and it’s dissipation through the producing system, as defined in chapter2. The use of Darcy's Law was discussed and in particular its application in radial co-ordinates. The response of the system to the of depletion was defined by two models namely the steady state model in which no depletion occurs and the semi or pseudo steady state model in which the outer boundary is closed.

Initially we considered for single phase flow the case of incompressible fluids such as liquids, which approximately have a constant viscosity and density. The case of slightly compressible fluids such as volatile oils and compressible fluids such as gas were then considered.

The concept of Productivity Index was presented as a sample means of characterising well deliverability. For both the incompressible and slightly compressible fluids it was demonstrated that the PI was constant over a wide range of conditions. However, for gas it was clear that the PI would continuously decline with reducing pore pressure. The case of multi-phase flow in the reservoir was particularly relevant to solution gas drive reservoirs and the physics of the production process were discussed. The majority of pressure loss in oil wells is attributable to losses in the tubing string. Pressure drop in pipe was reviewed with respect to energy and momentum balances. The physical concepts of multi-phase flow in pipe was presented emphasising concepts such as flow patterns, slippage and hold up.

The representation of pressure-depth traverses using gradient curves was presented and their use in predicting bottomhole pressure requirements and their rate dependance, through a tubing performance relationship was outlined.

The need for chokes was presented as a means of imposing production control. The sizing and performance of chokes as predicted by a number of correlation was discussed.

Finally, the integration of predicting both inflow and tubing performance requirements was considered to define and select tubing sizes as well as optimise well design.

EXERCISE 1.
STEADY STATE RADIAL FLOW AND PERTURBATIONS IN AN OIL WELL

1. An oil well in the middle of a large reservoir which is actively supported by water drive, has been openhole tested and yields the following data:

   B_o = 1.2
   μ = 0.8 cp
   r_w = 3 inches
   Thickness of interval tested h = 50 ft
   P_{wf} = 3800 psig at q = 3000 STB/d

It is estimated that the reservoir has a drainage radius of at least 1000 ft. Pressure survey both prior to and on build-up after the test indicate an original/static reservoir pressure of 4500 psig. The well can be assumed to penetrate the reservoir vertically. Because of the water drive you can assume that the reservoir performance can be modelled by a steady state flow model which gives the following equation:

$$P_e - P_w = 141.2 \frac{q \mu B_o}{Kh} \bullet \ell n \frac{r_e}{r_w} \qquad (1)$$

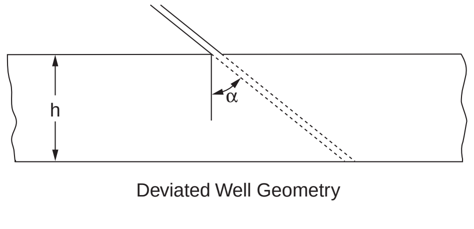
Calculate the reservoir permeability and PI assuming no damage to the reservoir.

2. For the well described in Question 1, calculate the relationship between P_{wf} and q. What would be the pressure P_{wf} for flowrates of 1000, 2000, 4000 and 5000 STB/d?

3. Assuming that a larger tubing diameter than that used for the well test can be used, allowing a bottom hole pressure of 2500 psig to be obtained, what would be the flowrate?

4. Assuming a bottomhole flowing pressure of 2500 psig, would any advantage exist in terms of production rate if the well was under-reamed to a diameter of 10 inches throughout the entire length of the productive interval?

5. If development of the reservoir was to proceed, then it is likely that the wells would be directionally drilled at angles up to 60º. Calculate the production rates achievable with a bottomhole pressure of 2500 psig at angles of 15º, 45º and 60º? Assume that the well has r_w = 3". The skin factor can be obtained from Figure 1.



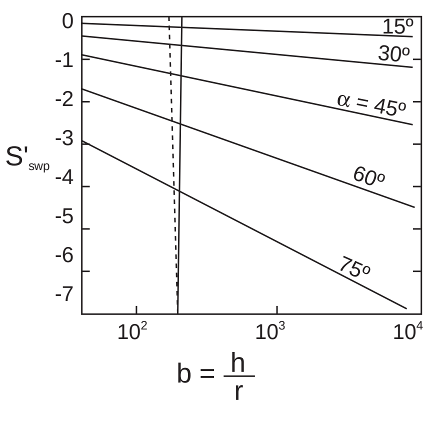
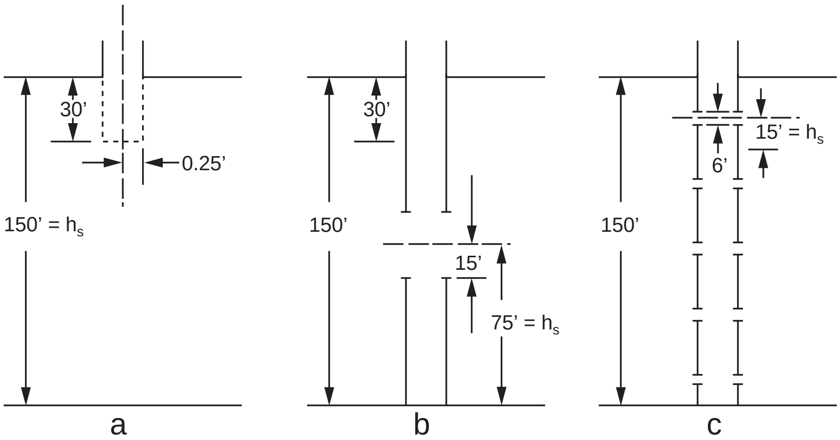


Figure 1
Pseudoskin factor, S_{swp}, for deviated wells (after Cinco, Miller and Ramey)

6. Since there is a very active underlying aquifer it may be desirable not to produce from the entire interval thickness to delay water breakthrough. If only the top 25 ft of the interval were drilled, what would be the effect on productivity if as before p_{wf} were restricted to 3500 psig and permeability isotropy existed? If the vertical permeability was only 10% of the horizontal permeability what production rate would be achieved? Assume r_w = 3". The skin factor can be obtained from Figure 2.



Examples of Partially Penetrating or Completed Wells

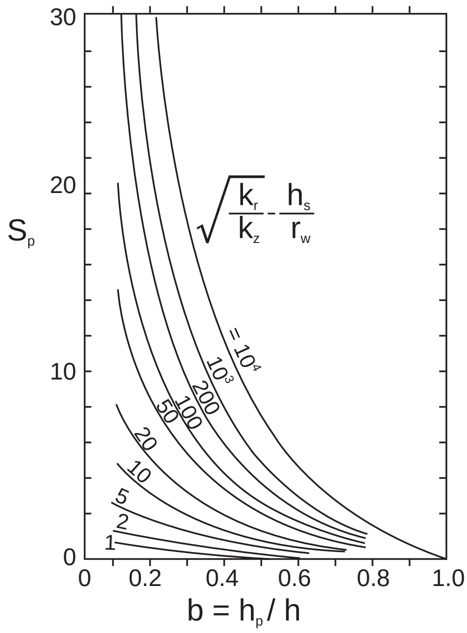


Figure 2
Pseudoskin factor, S_p, as a function of penetration ratio and the symetery parameter (Brons and Martin)

EXERCISE 1. SOLUTION.
STEADY STATE RADIAL FLOW AND PERTURBATIONS IN AN OIL WELL

The basic assumptions are that the steady state radial inflow equation for an incompressible fluid can be used:

$$P_e - P_w = 141.2 \frac{q \mu B_o}{Kh} \bullet \ell n \frac{r_e}{r_w} \qquad (1)$$

with all quantities expressed in field units.

1. The determination of the permeability is easily accomplished by inputting the known data into Equation 1.

$$(4500 - 3800) = \frac{141.2\,x\,3000\,x\,0.8\,x\,1.2}{K\,x\,50} \bullet \ell n \frac{1000}{0.25}$$

K = 96.3 md

It has been assumed that the reservoir has been tested open hole.

2. Obviously as the required flowrate is increased the drawdown on the reservoir increases and accordingly the bottomhole pressure must decline.

The easiest way of calculating the relationship between q and P_{wf} is to define the generalised equation and calculate the unknown parameter i.e. P_{wf} for a range of assumed values of q.

From Equation 1:

$$\left(4500 - P_{wf}\right) = \frac{141.2\,x\,q_s\,x\,0.8\,x\,1.2}{96.3\,x\,50} \bullet \ell n\, 4000$$

$$= \; 0.23349\, q$$

$$P_{wf} + 0.23349\, q = 4500$$

q STD/d	**P_{wf}** psig
0	4500
1000	4266
2000	4033
3000	3800
4000	3566
5000	3333

It can also be seen that P_{wf} drops by approximately 233 psi/1000 BOPD and this arises from the straight line IPR inherent in the steady state flow assumption.

$$P.I. = \frac{1000}{233} = 4.28 \text{ BPD / psi}$$

3. In the question, the impact of reducing the requirements for pressure loss in the tubing, is studied. By increasing the tubing size we can reduce the pressure loss and hence allow a greater drawdown to be utilised. The situation often occurs because of the ease of using smaller tubings for well testing compared to the subsequent development of wells which will be completed.

From Equation 1, assume P_{wf} = 2500 psig

$$(4500 - 2500) = \frac{141.2 \text{ x } q \text{ x } 0.81.2}{96.3 \text{ x } 50} \bullet \ell n\, 4000$$

Hence q = 8565 STB/day

4. From open hole productivity analysis it can be seen that $q \propto \ell n\,(r_e/r_w)$

Hence if the bottomhole radius can be increased to 5" we can expect higher flowrates.

$$(4500 - 2500) = \frac{141.2 \text{ x } q_s \text{ x } 0.8 \text{ x } 1.2}{96.3 \text{ x } 50} \bullet \ell n \frac{1000}{0.42}$$

$$\mathbf{q = 9137\, STB / d}$$

5. If an open borehole presents a reservoir at an angle to the vertical, the cross sectional area of the wellbore available for flow will be increased and hence pressure drop decreases and productivity increased.

The modification of Equation 1 to incorporate a skin factor S is:

$$P_e - P_{wf} = 141.2 \frac{q_s \mu B}{Kh} \left| \ell n \frac{r_e}{r_w} + S \right| \qquad (2)$$

Based upon P_{wf} = 2500 psi

$$(4500 - 2500) = \frac{141.2 \text{ x } q_s \text{ x } 1.2 \text{ x } 0.8}{96.3 \text{ x } 50} \bullet \ell n\; 4000 + S$$

i.e. 2000 = 0.028 q (8.294 + S)

From the Cinco Miller Ramey charts using:

$$\frac{h}{r_w} \frac{50}{0.25} = 200$$

Angle	S	Qs/STB/d
0	0	8612
15°	-0.2	8825
30°	-0.6	9284
45°	-1.25	10140
60°	-2.4	12119

The difference in productivity is quite substantial. It is also clear conversely that when comparing productivities of different wells on tests, we must back out the deviation skin factor to establish the base productivity.

6. The basic assumption is steady state radial flow is that when a well penetrates a formation the entire thickness of the formation is available to deliver fluid into the wellbore.

Again the potential completion/penetration skin factor will be calculated using the method proposed by Brons and Martin and the values for S will be input to Equation 2.

$$b = \frac{h_p}{h} = \frac{25}{50} = \frac{1}{2}$$

The parameter a is defined as:

$$\frac{h_s}{r_w}\sqrt{\frac{K_r}{K_v}}$$

(a) For the Isotropic case i.e. $K_v = K_r$:

$$h_s = 50'$$

$$a = \frac{50}{0.25}\sqrt{\frac{1}{1}} = 200$$

(b) For the Anisotropic case:

$$h_s = 50'$$

$$a = 200\sqrt{\frac{K_r}{0.1K_v}} = 632.45$$

From Equation 2:

$$1000 = 0.028q(8.294 + S)$$

	S	
Isotropic case	4	2905
Anisotropic case	5	2686

For the fully penetrating case the production rate q was 4306 STB/d.

From the above, it is clear that the partial penetration has reduced the productivity by about 30%. However, it is apparent that the degree of anisotropy is not substantial, accounting for only about a further 10% reduction in productivity. It would clearly take a substantial degree of anisotropy $K_r/K_z = 10^2 - 10^4$ to give a substantial effect in this case.

EXERCISE 2.
EFFECT OF SKIN FACTOR ON WELL PERFORMANCE

$$FE = \frac{q_D}{q_{UD}} = \frac{\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75\right]}{\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S\right]}$$

For an 8" dia hole (r_w = 0.333ft) and a reservoir drainage radius of 1000 ft, calculate the impact of a variable skin factor on the flow efficiency as follows:

S	F.E.
- 2	
0	
+ 2	
+ 6	
+ 12	
+ 20	
+ 30	
+ 100	

Assume $\ln\left(\frac{r_e}{r_w}\right)$ has a value of 8

EXERCISE 2. SOLUTION.
EFFECT OF SKIN FACTOR ON WELL PERFORMANCE

$$\ln\left(\frac{r_e}{r_w}\right) = \ln\left(\frac{1000}{0.333}\right) \approx 8$$

$$\text{Flow Efficiency.} = \frac{8-0.75}{8-0.75+S} = \frac{7.25}{7.25+S}$$

S	FE	FE %
- 2	1.38	138
0	1.0	100
+ 2	0.78	78
+ 6	0.55	55
+ 12	0.38	38
+ 20	0.27	27
+ 30	0.19	19
+ 100	0.07	7

EXERCISE 3.
FLOWING BOTTOMHOLE PRESSURE PREDICTION - GILBERT

Using the attached gradient curves (figures 3-7).

1. A well completed with 10,000 ft of 2 $^7/_8$" tubing is flowing at a rate of 600 B/D with a gas-liquid ratio of 1.0 MCF/BBL. Assuming a tubing head pressure of 300 psi, calculate the bottomhole flowing pressure.

2. For the above well 1, calculate the variation in bottomhole flowing pressure at various rates of 50, 100, 200, 400 BOPD.

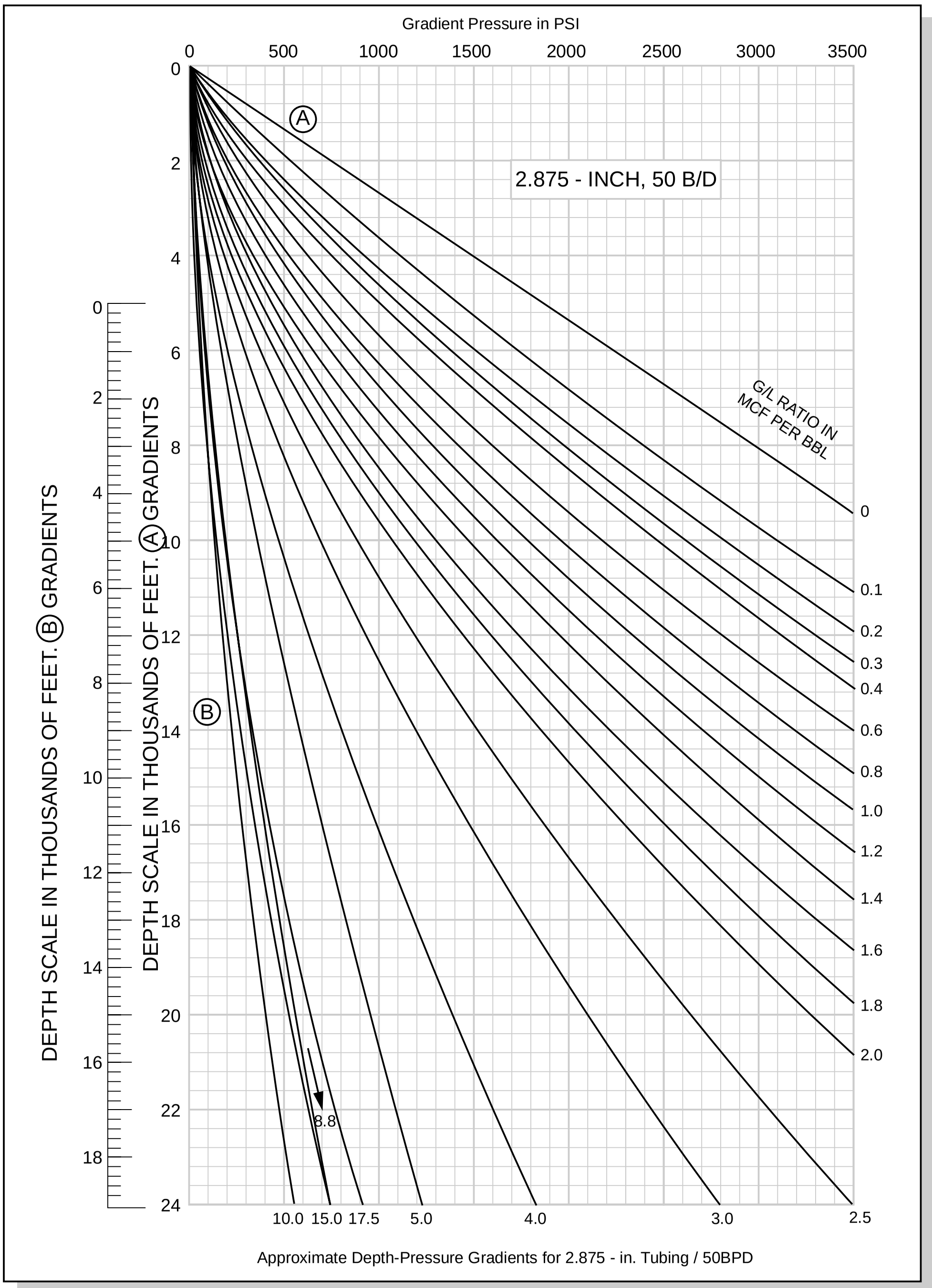

Gradient Pressure in PSI
0 500 1000 1500 2000 2500 3000 3500
DEPTH SCALE IN THOUSANDS OF FEET. A GRADIENTS
DEPTH SCALE IN THOUSANDS OF FEET. B GRADIENTS
A
B
2.875 - INCH, 50 B/D
G/L RATIO IN MCF PER BBL
0 0.1 0.2 0.3 0.4 0.6 0.8 1.0 1.2 1.4 1.6 1.8 2.0 2.5 3.0 4.0 5.0 17.5 15.0 10.0
8.8
Approximate Depth-Pressure Gradients for 2.875 - in. Tubing / 50BPD

Figure 3

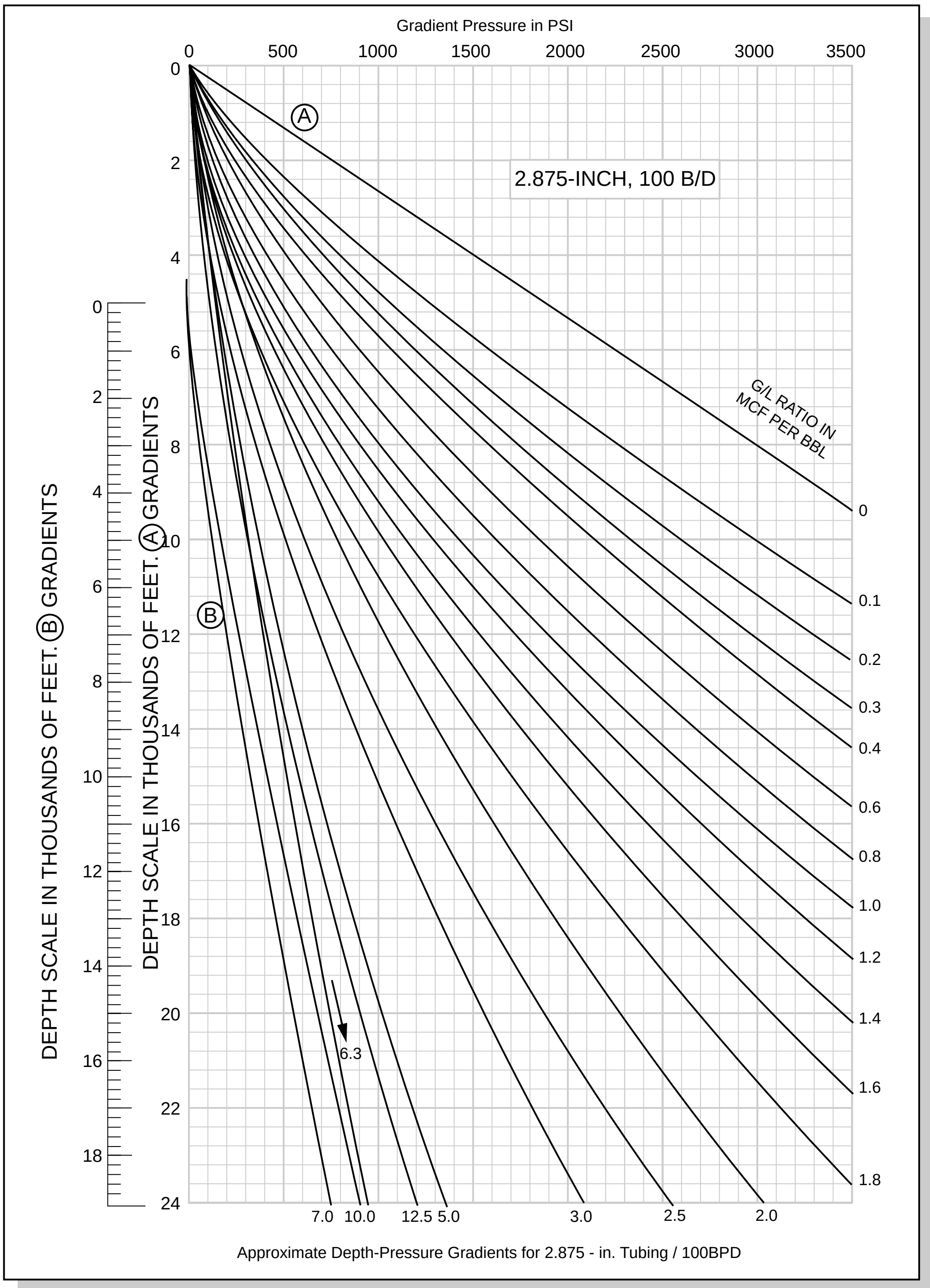

Gradient Pressure in PSI
0 500 1000 1500 2000 2500 3000 3500
2.875-INCH, 100 B/D
A
B
G/L RATIO IN MCF PER BBL
0 0.1 0.2 0.3 0.4 0.6 0.8 1.0 1.2 1.4 1.6 1.8
7.0 10.0 12.5 5.0 3.0 2.5 2.0
6.3
DEPTH SCALE IN THOUSANDS OF FEET. A GRADIENTS
0 2 4 6 8 10 12 14 16 18 20 22 24
DEPTH SCALE IN THOUSANDS OF FEET. B GRADIENTS
0 2 4 6 8 10 12 14 16 18
Approximate Depth-Pressure Gradients for 2.875 - in. Tubing / 100BPD

Figure 4

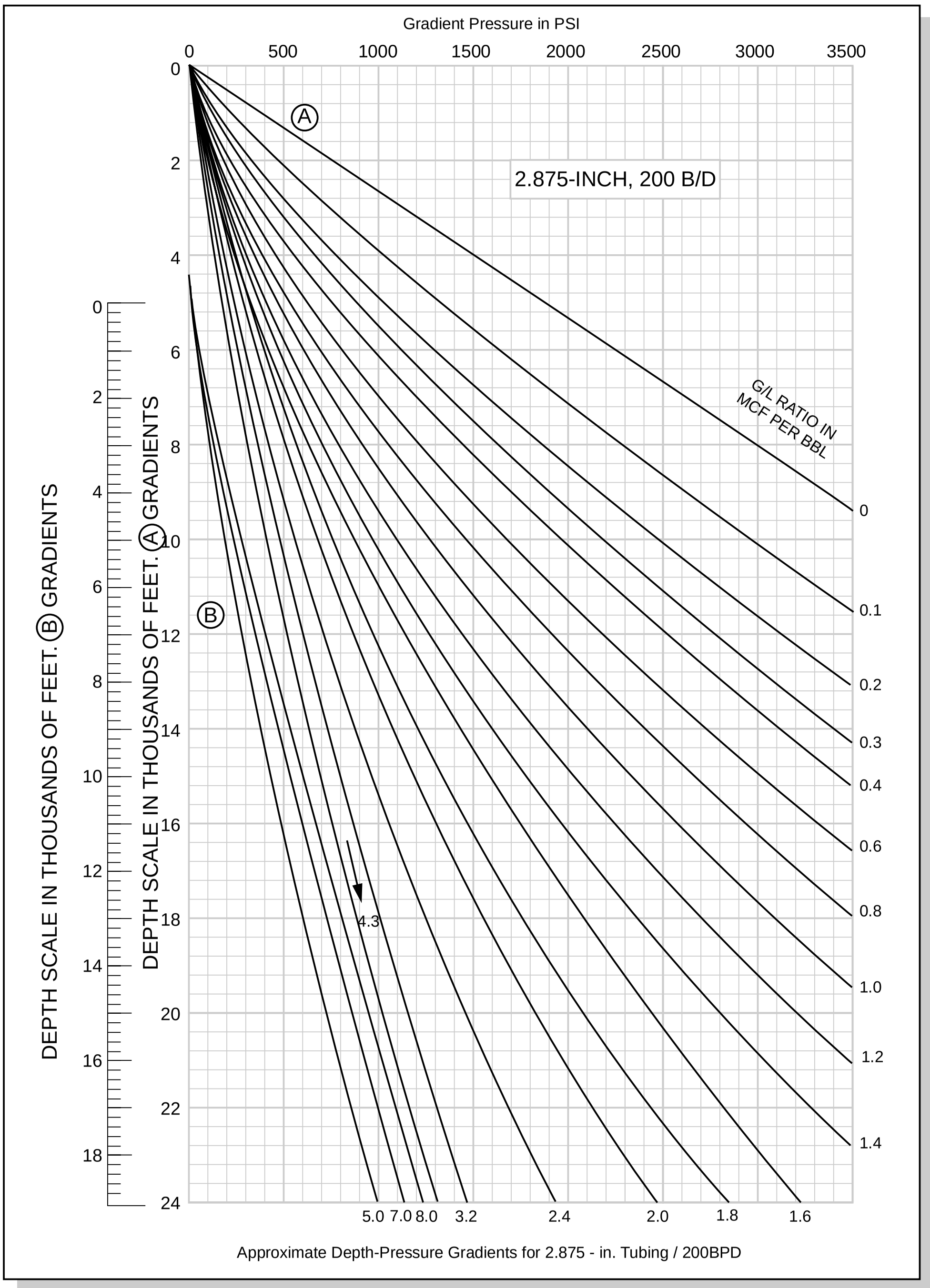

Gradient Pressure in PSI
0
500
1000
1500
2000
2500
3000
3500
DEPTH SCALE IN THOUSANDS OF FEET. B GRADIENTS
DEPTH SCALE IN THOUSANDS OF FEET. A GRADIENTS
A
B
2.875-INCH, 200 B/D
G/L RATIO IN MCF PER BBL
0
0.1
0.2
0.3
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
2.4
3.2
4.3
5.0 7.0 8.0
Approximate Depth-Pressure Gradients for 2.875 - in. Tubing / 200BPD

Figure 5

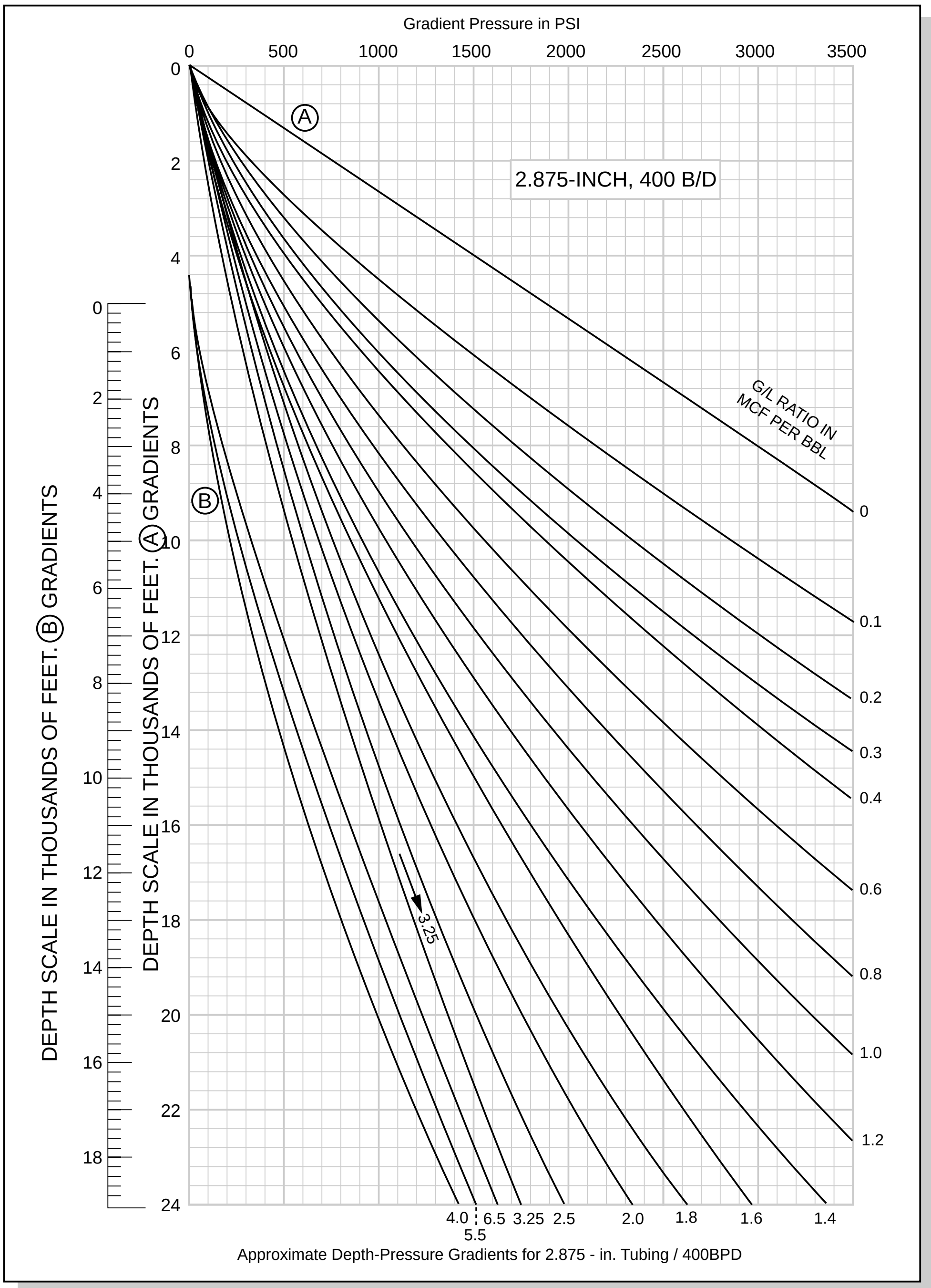

Gradient Pressure in PSI
0
500
1000
1500
2000
2500
3000
3500
2.875-INCH, 400 B/D
A
B
G/L RATIO IN MCF PER BBL
0
0.1
0.2
0.3
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
2.5
3.25
6.5
5.5
4.0
3.25
DEPTH SCALE IN THOUSANDS OF FEET. A GRADIENTS
0
2
4
6
8
10
12
14
16
18
20
22
24
DEPTH SCALE IN THOUSANDS OF FEET. B GRADIENTS
0
2
4
6
8
10
12
14
16
18
Approximate Depth-Pressure Gradients for 2.875 - in. Tubing / 400BPD

Figure 6

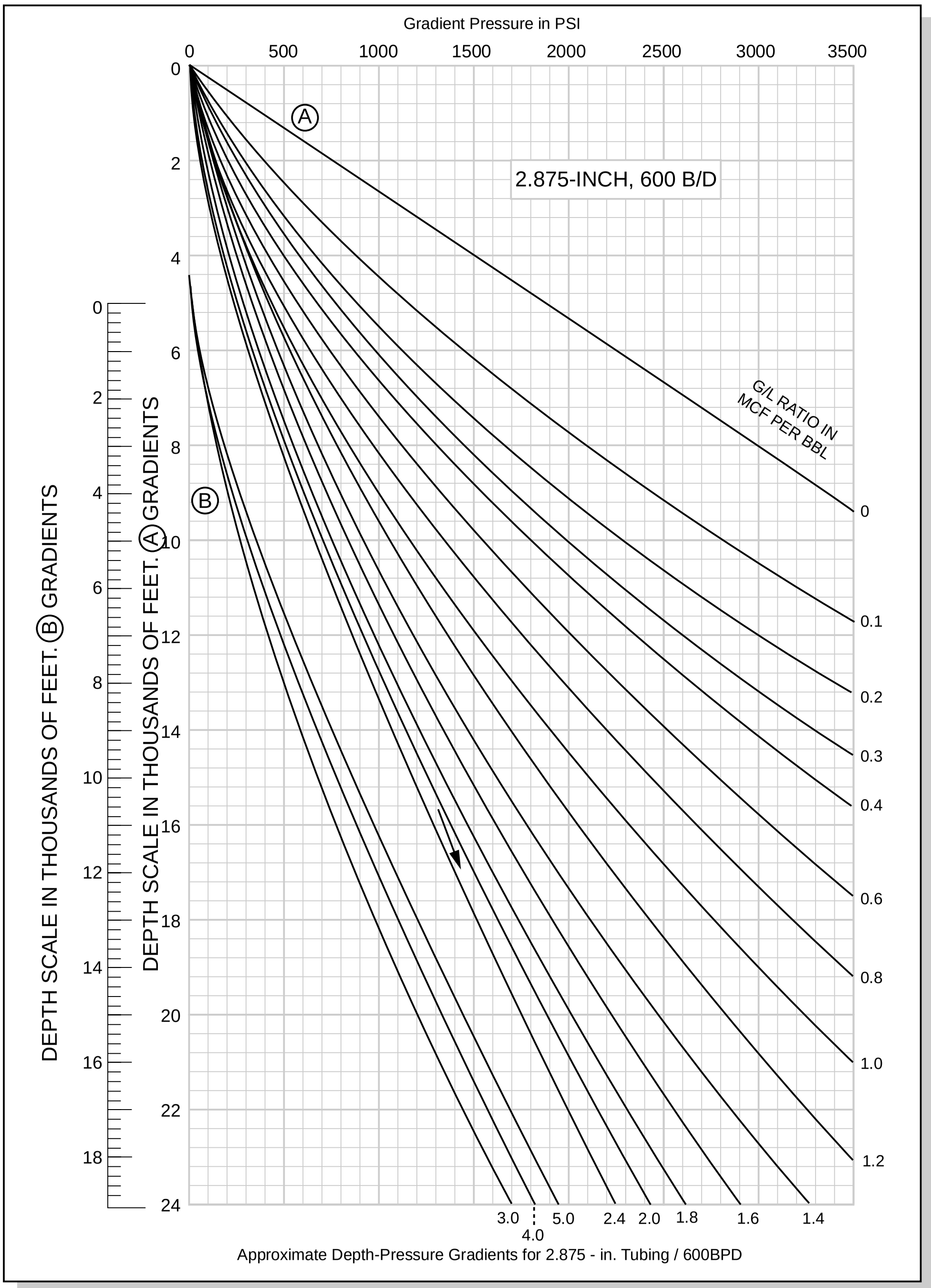

Gradient Pressure in PSI
0
500
1000
1500
2000
2500
3000
3500
2.875-INCH, 600 B/D
A
B
G/L RATIO IN MCF PER BBL
0
0.1
0.2
0.3
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
2.4
5.0
4.0
3.0
DEPTH SCALE IN THOUSANDS OF FEET. A GRADIENTS
DEPTH SCALE IN THOUSANDS OF FEET. B GRADIENTS
Approximate Depth-Pressure Gradients for 2.875 - in. Tubing / 600BPD

Figure 7

EXERCISE 3. SOLUTION.
FLOWING BOTTOMHOLE PRESSURE PREDICTION - GILBERT

1. Refer to Gilbert's curve for 2 $^7/_8$" tubing, 600 B/D (Figure 7). Using the chart it can be calculated that for a GLR of 1.0, the depth equivalent to a THP of 300 psi is 3600'.

To calculate the bottomhole flowing pressure, its equivalent depth would be 13600' and again using the chart, the bottomhole pressure is 1850 psi.

2. Using each of the 2 $^7/_8$" tubing gradient curves for 50, 100, 200 and 400 bbls/d, we can estimate the bottomhole flowing pressure P_{wf} for each flowrate.

Flowrate bbl/d	THP psi	Depth equiv. to THP/ft.	Actual depth ft	Total equiv. depth/ft	P_{wf} /psi
50	300	2700	10,000	12,700	2600
100	300	3500	10,000	13,500	2300
200	300	3700	10,000	13,700	2030
400	300	4000	10,000	14,000	1930

EXERCISE 4.
CALCULATION OF THE OPERATING FLOWRATE FOR AN OIL WELL

1. A well is completed with 6,000 ft of 2 $^7/_8$" tubing. The bottomhole static pressure is 2,000 psi and the PI is 0.25 BBL/Day/psi. Additionally the GLR is 300 ft^3/BBL. Assuming a tubing head pressure of 100 psi, at what rate will the well flow? Use the gradient flow curves from exercise 3

EXERCISE 4. SOLUTION
CALCULATIONS OF OPERATING FLOWRATE FOR AN OIL WELL

The solution to this problem in which the flow rate is known, involves matching the IPR of the well with vertical flow performance relationship i.e. Gilbert's curves.

(a) Draw the IPR for the well using the PI of 0.25 B/D/psi, and the static pressure P_s of 2000 psi

when q = 0 pressure = P_s = 2000 psi

Prod. Index PI = 0.25

When P_{wf} = 0 q = 2000 x 0.25 = B/D

(b) The flowing well performance relationship must now be developed by calculating P_{wf} for various assumed flowrates using the THP of 100 psi.

Assumed Flow Rate Q BBL/Day	Equiv. Depth of a THP of 100 psi at assumed flow rate Ft	Equiv. Depth of well Ft	Bottomhole flowing pressure P_{wf} psi
50	500	6500	1540
100	700	6700	1380
200	750	6750	1280
400	800	6800	1200

From the above table, plot q versus P_{wf} (Figure 8) and the intersection of the curves yields a flow rate of 180 BBL/D, which satisfies both the IPR and the flowing tubing pressure drop relationship.

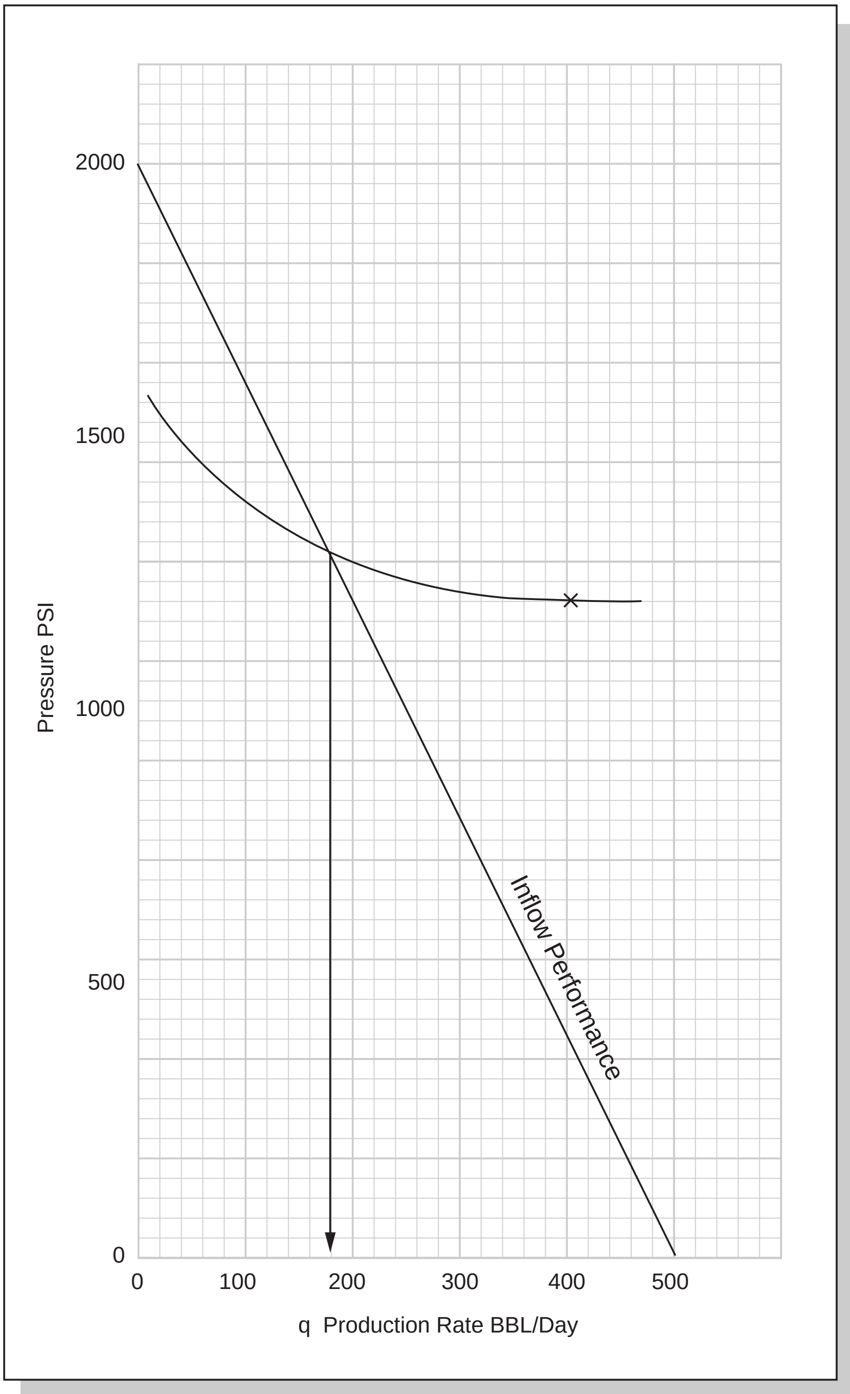


Figure 8
solution to exercise 4

EXERCISE 5 .
TUBING SIZE SELECTION

A decision has to be made on whether to use 3 in. or 4 in. ID tubing for a well with the following conditions:

Steady state inflow

Initial pressure	=	2,500 psi
PI	=	2.0 STB/psi
Bubble point pressure	=	1,200 psi
Depth (TVD)	=	5,000 ft
Required THP	=	300 psi
GOR	=	200 SCF/bbl

(i) Calculate the flow capacity of the well for 4 in. and 3 in. ID tubing using the attached gradient curves figures 9 to 14.

(ii) Comment on the general sizing of the available tubing strings.

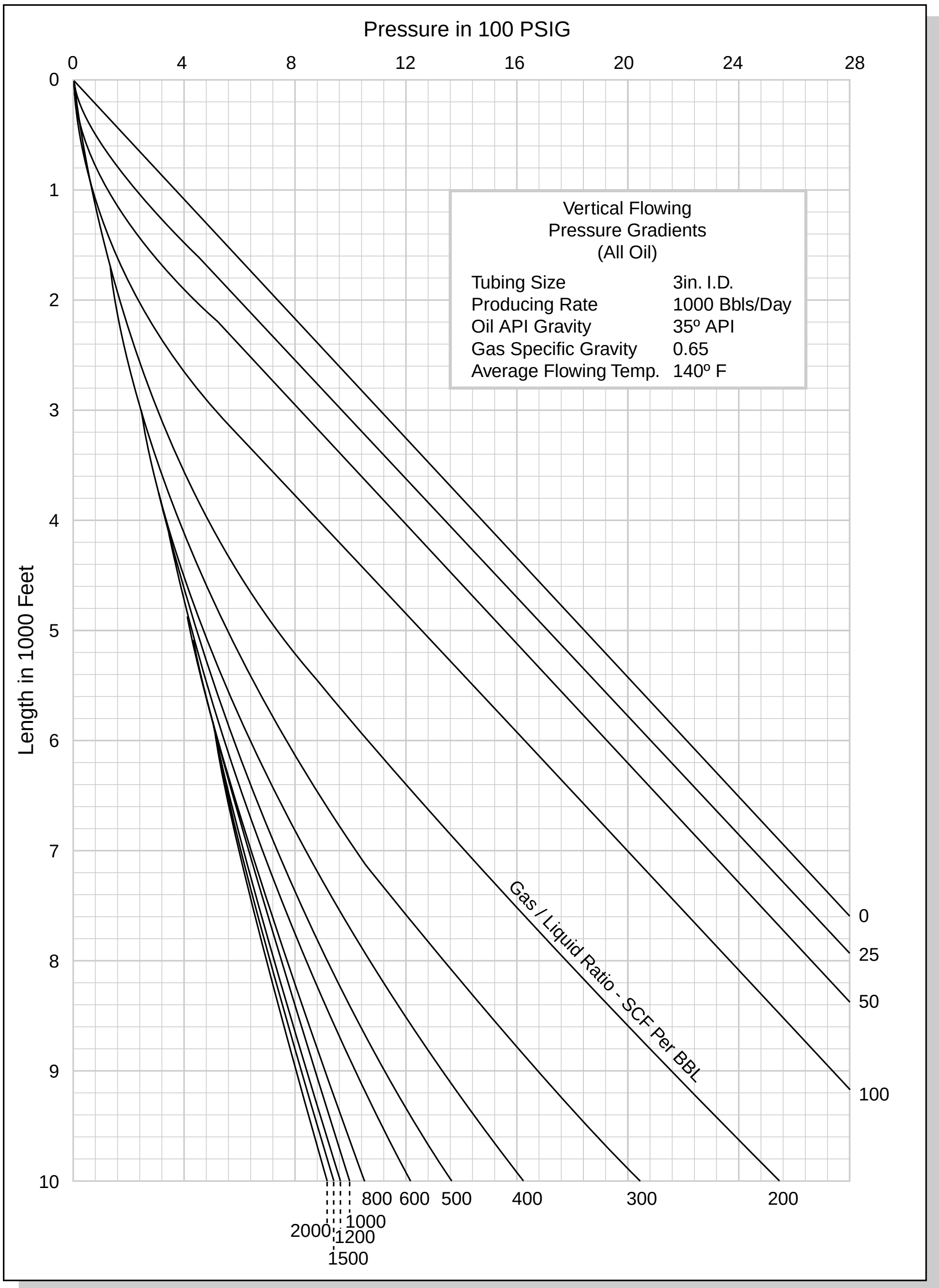

Pressure in 100 PSIG
0
4
8
12
16
20
24
28
Length in 1000 Feet
0
1
2
3
4
5
6
7
8
9
10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 3in. I.D.
Producing Rate 1000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
200
300
400
500
600
800
1000
1200
1500
2000

Figure 9

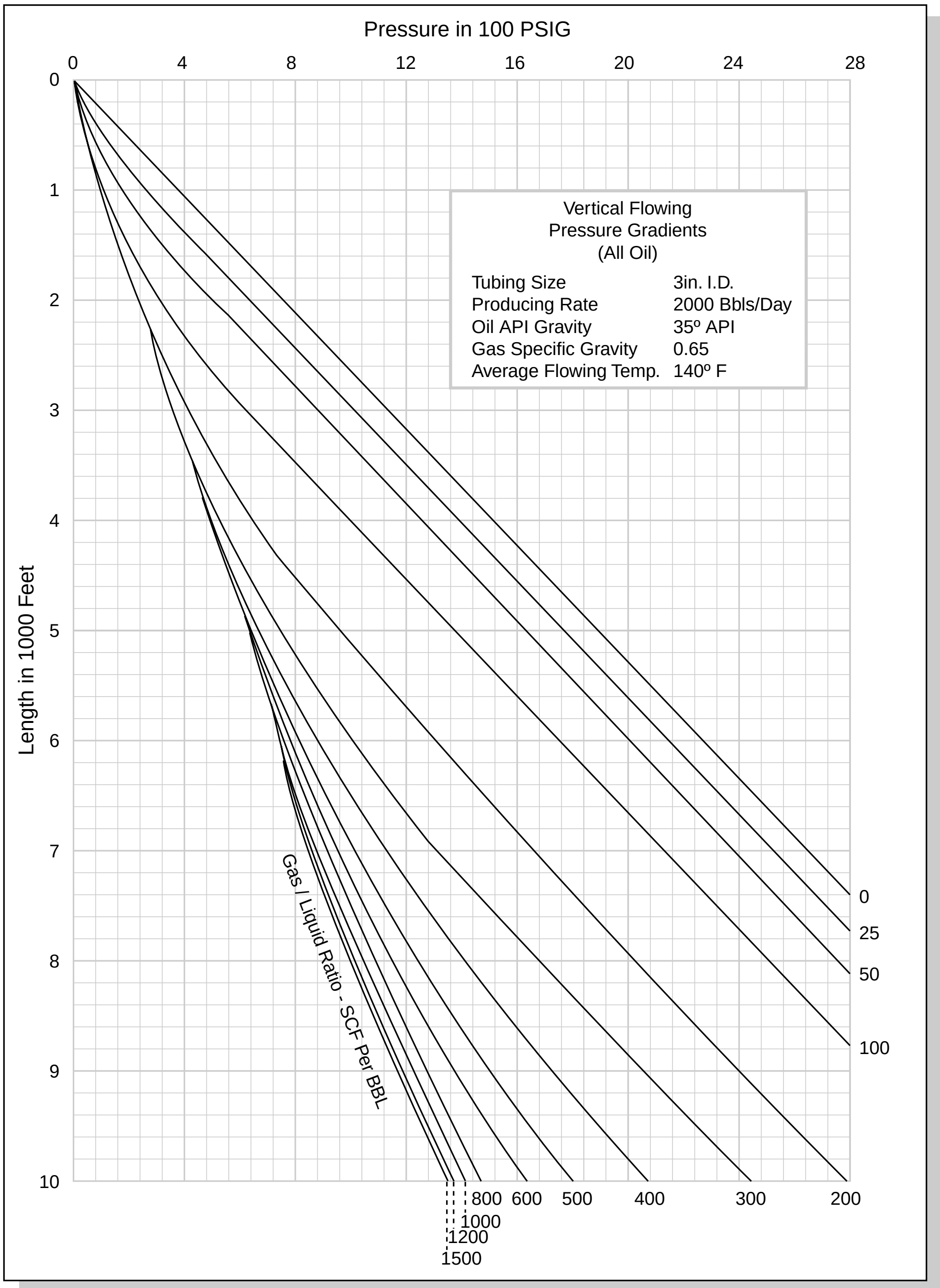
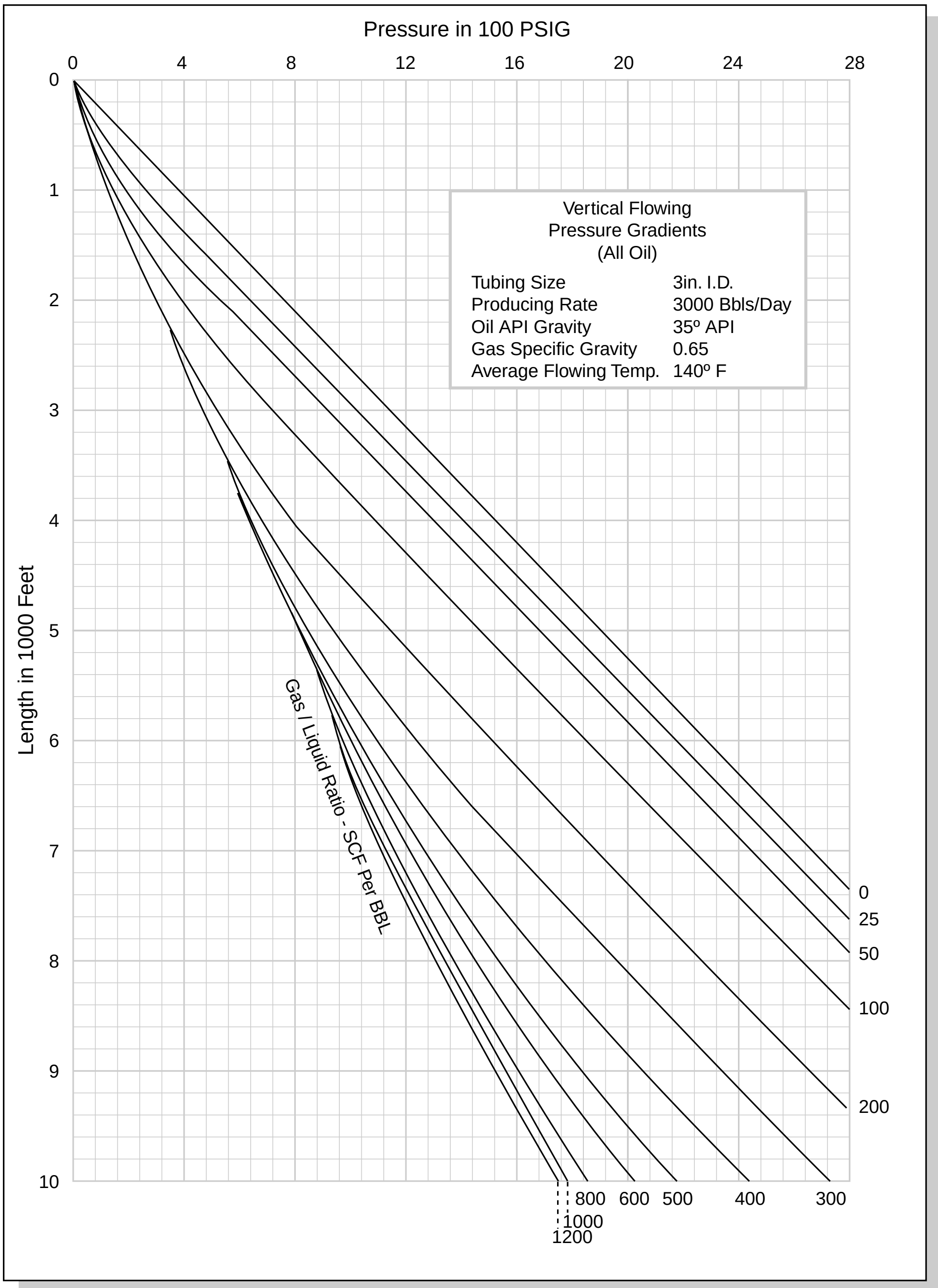
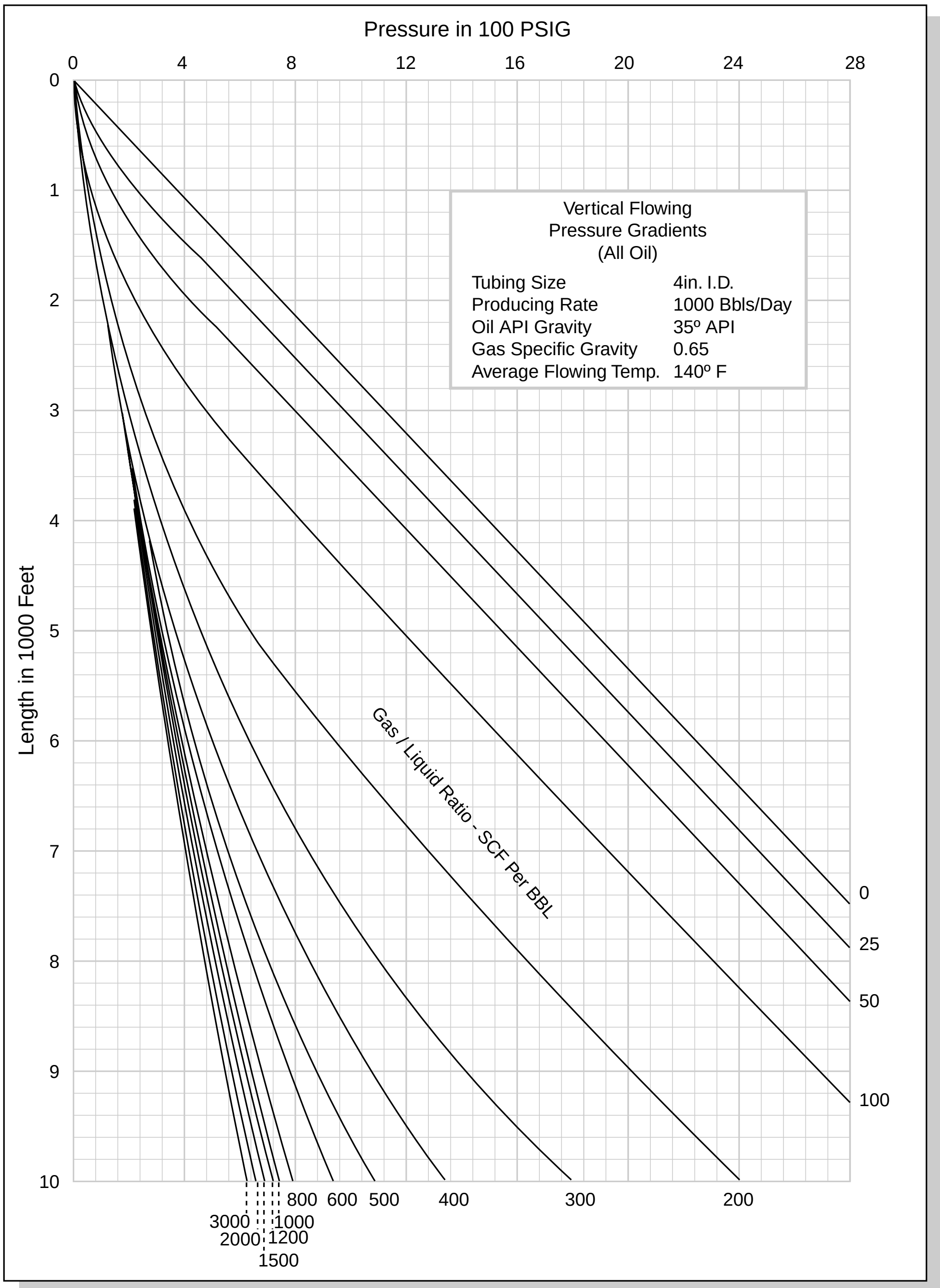

Pressure in 100 PSIG
0
4
8
12
16
20
24
28
Length in 1000 Feet
0
1
2
3
4
5
6
7
8
9
10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 3in. I.D.
Producing Rate 2000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
200
300
400
500
600
800
1000
1200
1500

Figure 10



Pressure in 100 PSIG
0
4
8
12
16
20
24
28
0
1
2
3
4
5
6
7
8
9
10
Length in 1000 Feet
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 3in. I.D.
Producing Rate 3000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
200
300
400
500
600
800
1000
1200

Figure 11



Pressure in 100 PSIG
0
4
8
12
16
20
24
28
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 1000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Length in 1000 Feet
0
1
2
3
4
5
6
7
8
9
10
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
200
300
400
500
600
800
1000
1200
1500
2000
3000

Figure 12

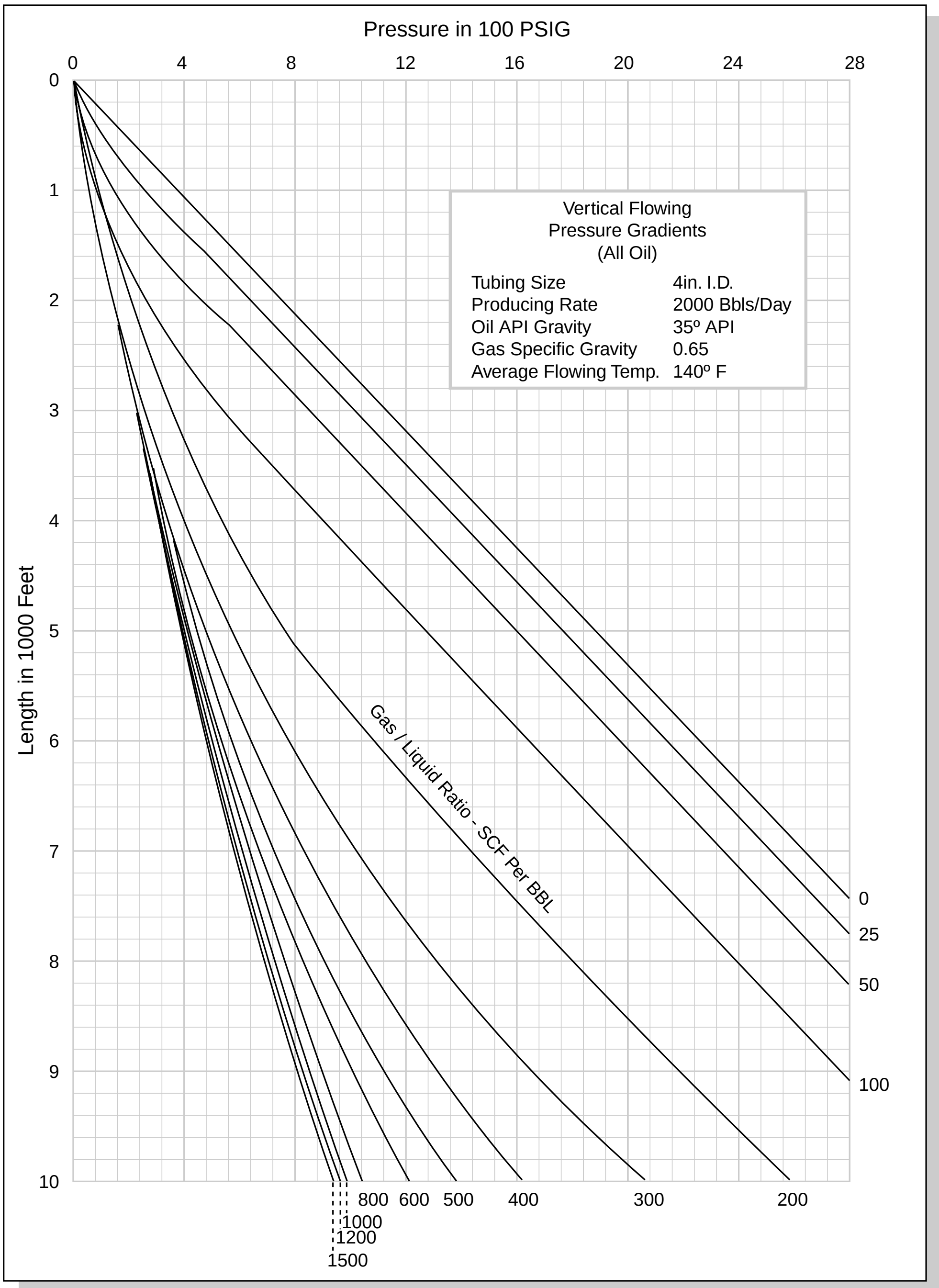
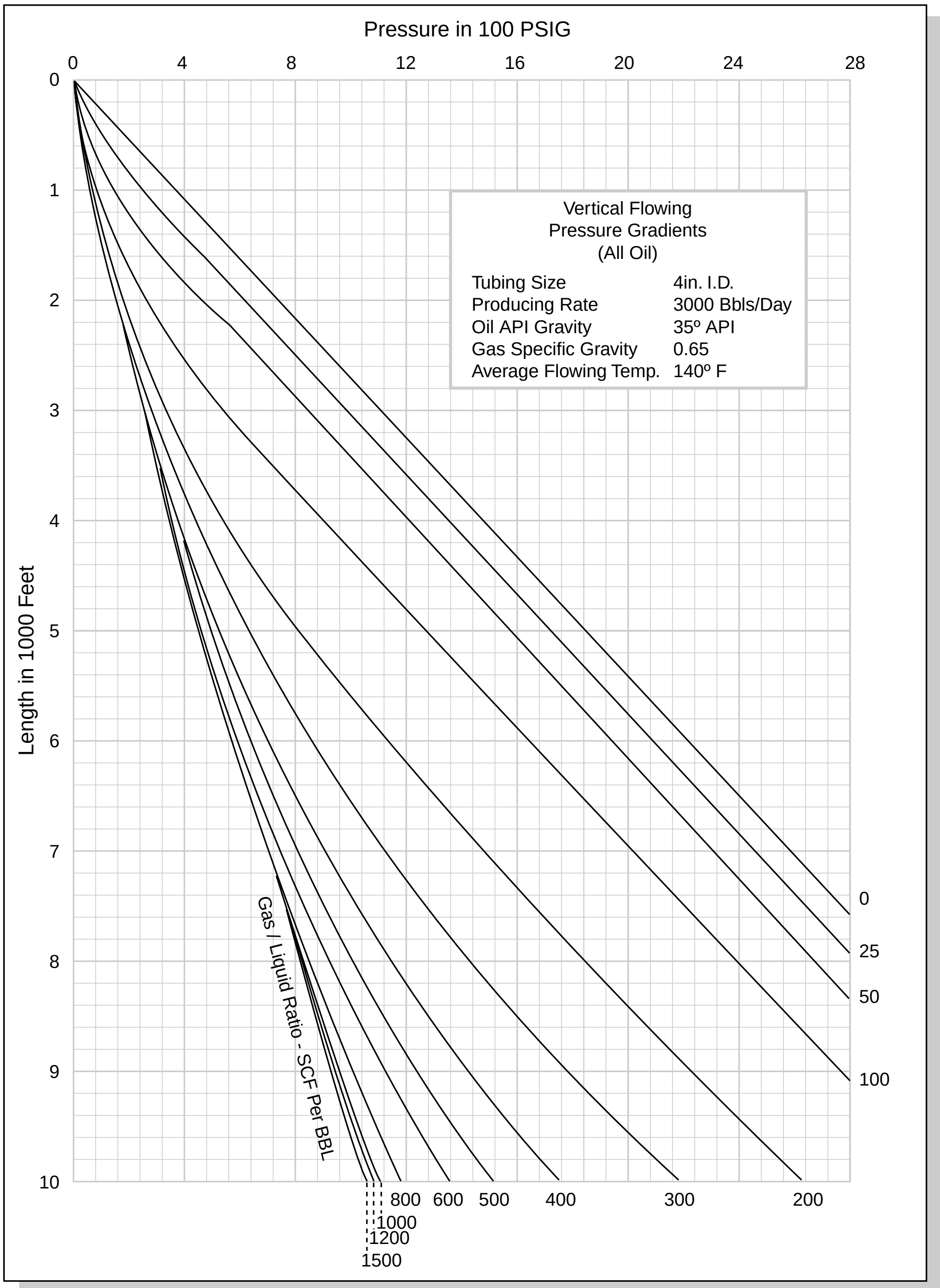

Pressure in 100 PSIG
0
4
8
12
16
20
24
28
Length in 1000 Feet
0
1
2
3
4
5
6
7
8
9
10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 2000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
200
300
400
500
600
800
1000
1200
1500

Figure 13



Pressure in 100 PSIG
0
4
8
12
16
20
24
28
Length in 1000 Feet
0
1
2
3
4
5
6
7
8
9
10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 3000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
200
300
400
500
600
800
1000
1200
1500

Figure 14

EXERCISE 5. SOLUTION.
TUBING SIZE SELECTION

1. Plot the IPR

Assume P_i : 2,500 psi

IPR must pass through : Q=2,000 stb/d and P_{wf}=1,500 psi

Plot P_{wf} versus Q

2. Construct TPR curves

Tubing Size (inch)	Rate (BOPD)	THP (psi)	Actual depth(ft)	Depth Equivalent to THP(ft)	Total Equivalent depth (ft)	P_{wf} (psi)
4	1000	300	5000	3346	8346	1720
	2000	300	5000	2600	7600	1630
	3000	300	5000	2800	7800	1723
3	1000	300	5000	2964	7964	1738
	2000	300	5000	2400	7400	1770
	3000	300	5000	1960	6960	1815

3. Plot P_{wf} versus Q and read intersection points as per figure 15.

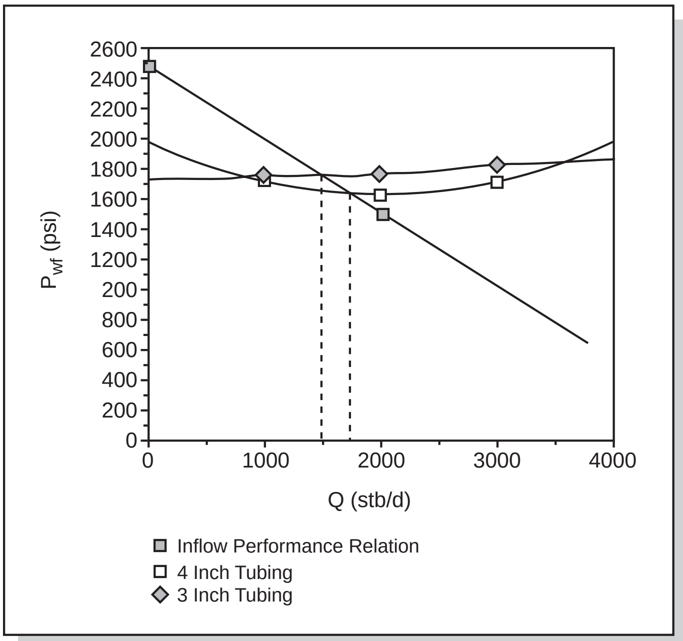


Figure 15

In summary the well will flow approximately as follows:

Tubing	Production Rate
3" ID	1500 b/d
4" ID	1650 b/d

CONTENTS

LEARNING OBJECTIVES:

Having worked through this chapter the Student will be able to:

- Evaluate for a given reservoir scenario the bottom hole completion options and make a recommendation based on well integrity and reservoir management requirements.

- Assess and recommend geometrical configurations for drilled wellbores for both production and injection applications.

- Identify, evaluate and recommend functional capability of completion strings for a variety of situations.

- Describe the purpose and generic operating principles for major completion equipment components.

- Identify limitation of well completion schematical designs and potential failure mechanisms/operational problems with equipment.

- Assess well safety requirements and capabilities inherent in well design.

INTRODUCTION

In the development of a hydrocarbon reservoir, a large number of wells are drilled and require to be completed, to allow the structure to be depleted. However, the drilling and completion operations are crucial to the long term viability of the wells in meeting the specified objectives. The design and completion of both production and injection wells are required to satisfy a number of objectives including:

1. Provision of optimum production/injection performance.

2. Ensure safety.

3. Maximise the integrity and reliability of the completion over the envisaged life of the completed well

4. Minimise the total costs per unit volume of fluid produced or injected, i.e. minimise the costs of initial completion, maintaining production and remedial measures.

Depending upon the reservoir characteristics or development constraints, the completion may be required to fulfil other criteria, e.g. to control sand production.

The design of a completion can therefore be assumed to proceed concurrently at two different levels. The initial intention would be to produce a conceptual design, or a series of alternatives. From these conceptual designs, one or more would be selected for more detailed development. Thereafter, a detailed design process would be pursued with the intention of producing a completion string design which specifies all components and also assesses the sensitivity of the well and completion performance to variations in the reservoir data used for the design.

The fundamental design of a completion consists of four principal decision areas, namely:

1. Specification of the bottom hole completion technique.

2. Selection of the production conduit.

3. Assessment of completion string facilities.

4. Evaluation of well performance / productivity-injectivity

These four decision areas, as shown in Figure 1, should provide a conceptual design for the completion of the wells. However, this design process normally is initiated on the basis of data from exploration wells and considerable uncertainty may exist as to the validity and accuracy of that data. Thus a number of alternative designs for well completions will normally be selected and retained as a contingency.

Subsequently, the detailed design and evaluation of the selected completion concept will be undertaken. In this phase of the design the objectives will be to:

1. Specify all equipment and materials

2. Optimise completion performance

3. Optimise well performance.

It is essential that at both the conceptual and detailed design stages, an interactive approach is adopted. The interactive nature of completion design and the diversity of design data, e.g. reservoir rock and fluid properties, production constraints etc. and the range of disciplines which have inputs to the decision making process, e.g. drilling engineers, reservoir engineers and production technologists, necessitates a broad and far reaching design process. A synergistic approach to completion design is essential.

In this chapter, the decision areas associated with the development of a conceptual design for a well completion are discussed.

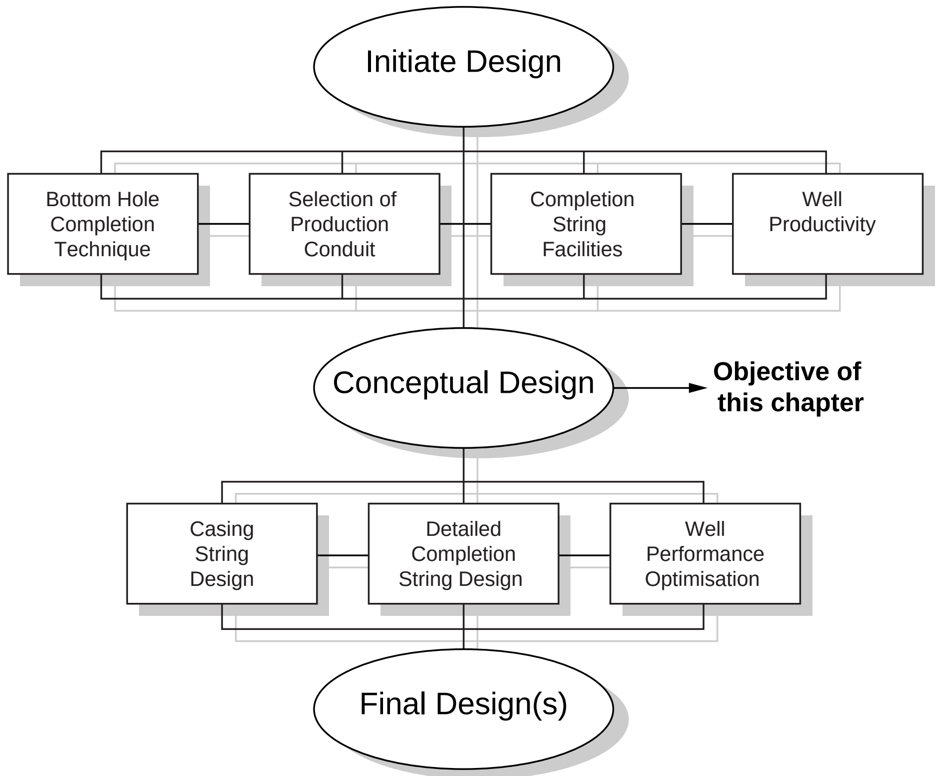


Figure 1 Completion Design Strategy

1. BOTTOM HOLE COMPLETION TECHNIQUES

Once the borehole has been drilled through the reservoir section of interest for production or injection, the method by which fluid communication will occur between the reservoir and the borehole, after completion, has to be decided. There are 3 alternative approaches for the completion of the reservoir zone:

1. Open hole completion

2. Pre-drilled / pre-slotted liner or screen completion (uncemented).

3. Casing or liner with annular cementation and subsequent perforation.

1.1 Open hole completion

The simplest approach to bottom hole completion would be to leave the entire drilled reservoir section open after drilling, as shown in Fig 2. Such completions are sometimes referred to as "barefoot" completions and the technique is widely applied. Since no equipment requires to be installed there are savings in both costs and time. However this type of completion does mean that the entire interval is open to production and hence it often provides no real selective control over fluid production or injection. It is therefore not recommended for production or injection wells where distinctive variations in layeral permeability will detrimentally control the sweep efficiency on zones under water flood or gas injection. Further, in an oil well if water/gas breakthrough or migration into the wellbore occurs it is difficult to isolate unless the entry is at the base of the well where isolation with a cement plug may be successful. The possibility of interzonal cross flow or zonal back pressure dictating multizone depletion cannot be corrected with this type of completion. This lack of zonal control for production or injection is a major limitation on the application of this technique.

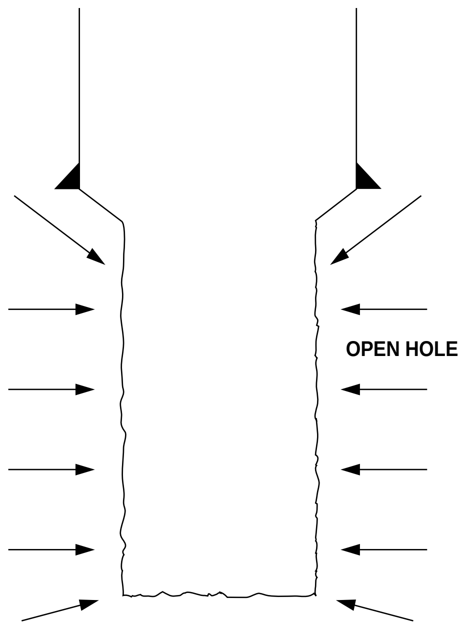


Figure 2
Open Hole Completion

Open hole completions should only be applied in consolidated formations as the borehole may become unstable once a drawdown in applied to induce the well to flow. In such cases either total collapse of the formation or the production of sand may occur.

Currently open hole completions are applied in a range of environments

a) Low cost / multi well developments
b) Deep wells, consolidated with depletion drive
c) Naturally fractured reservoirs
d) Some horizontal and multi lateral wells

1.2 Screen or pre-slotted liner completions

In this technique, once the drilling through completed reservoir section has been completed, a wire-wrapped screen or steel pipe which has slots or alternative sand control screen, is installed (Fig 3). The principal purpose of the screen or liner is to prevent any produced sand from migrating with the produced fluids, into the production flow string. The success of the completion in controlling sand production is dependent upon the screen or slot sizes and the sand particle sizes. The screen will only become 100% effective if it totally restrains sand production which requires that the slot size be equal to the size of the smallest particles. However, in such cases the slots may quickly become plugged and impede flow resulting in a loss in productivity. This system is sometimes used in inclined/high angle angles to prevent major borehole collapse or facilitate the passage of logging tools.

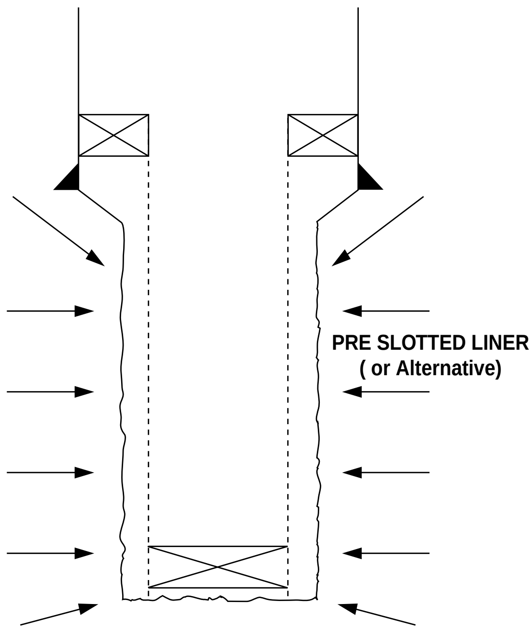


Figure 3
Well Completed with Wire Wrapped Screen or Slotted Liner

This technique also suffers from the same inability for zonal control of production or injection as exists in the open hole completion and may only effectively control sand production over a limited range of conditions. However, it is a low cost technique since the cost of a screen to cover the reservoir interval is much less than the cost of a casing string run to surface plus the cost of cementing and perforating. However in the case of using premium sand exclusion screens, the cost saving will be reduced.

The technique is therefore only of application as an alternative to the open hole completion in situations where the reservoir rock consists of relatively large and homogenous sand grains.

1.3 Cemented and perforated casing/liner

The final choice is to install either a casing string which extends back to surface or a liner which extends back into the shoe of the previous casing string, which would then be cemented in place by the displacement of a cement slurry into the annular space between the outside wall of the casing and the borehole wall (Fig 4). Subsequently, to provide flow paths for fluid to enter the wellbore from the formation, or vice versa, the casing and cement sheath will be perforated at selected locations using explosive charges contained in a perforating gun.

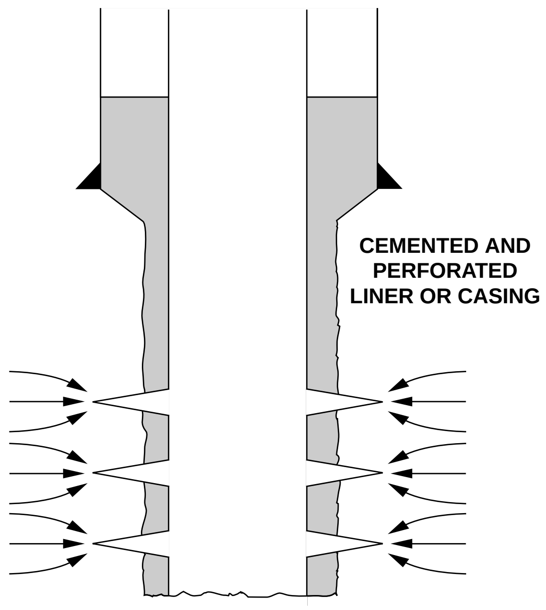


Figure 4
Cemented and Perforated Production Casing or Liner

The integrity and selectivity of the completion depends to a great extent on an effective hydraulic seal being located in the casing-formation annulus by the cement. For the completion to be effective, a successful primary cement job must provide zonal isolation behind the casing. The absence or failure of the cement can lead to either fluid migration behind the casing to surface, into another zone or into perorations from which it was assumed to be isolated. If required the perforations can subsequently be closed off by a cement squeeze operation.

This type of completion involves considerably greater costs and time than the previous options. The cost of a full length of casing from the surface to the base of the well can be considerable, to which must be added the cost of perforating, cementing and the additional time necessary to complete the borehole in this way. The use of a liner helps to reduce the required length of tubular and hence the overall costs. However the ability to control the depletion of individual zones, isolate the inflow of undesirable produced fluids and control the injection of fluids into zones are essential to a large number of developments and this has resulted in the cemented and perforated liner or casing being the most widely applied bottom hole completion technique in situations where enhanced reservoir management capabilities are required.

2. SELECTION OF THE FLOW CONDUIT BETWEEN THE RESERVOIR AND SURFACE

There are a number of optional methods by which fluid which enters the wellbore will be allowed to flow to surface in a production well, or to the formation in an injection well. In the selection of the method, a range of considerations may influence the choice including: cost, flow stability, ability to control flow and ensure well safety or isolation; ensuring that the integrity of the well will not be compromised by corrosion or erosion. In the case of multizone reservoir, the zonal characteristics will determine to a large extent the flow system selected.

However, for a single zone completion, the following alternatives exist:

1. Tubingless casing flow.
2. Casing and tubing flow.
3. Tubing flow without annular isolation.
4. Tubing flow with annular isolation.

These options are depicted in Fig 5

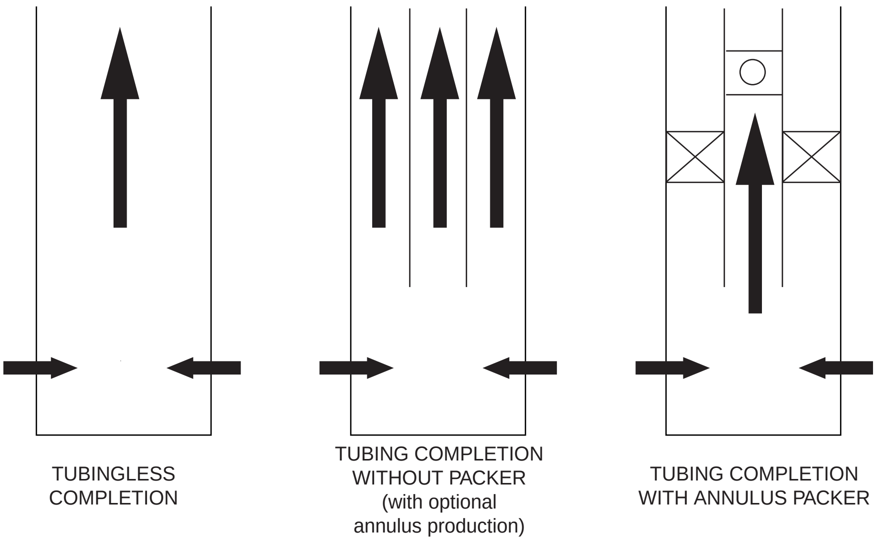


Figure 5
Selection of Production Condiut

2.1 Tubingless casing flow

In this option, once the well has been drilled and the bottom hole completion technique implemented, eg open hole or perforated casing, the well is induced to flow under drawdown and fluid is produced up the inside of the casing. This technique is very simple and minimises costs. However it is not without its disadvantages. Firstly, the production casing may be of such a diameter that the flow area is so large that the fluid superficial velocities are low enough for phase separation and slippage to occur, resulting in unstable flow and increased flowing pressure loss in the casing. To be effective, this approach is only applicable for high rate wells. Secondly, the fluid is in direct contact with the casing and this could result in any of the following:

1. Casing corrosion, if H_2S or CO_2 are present in produced fluids.

2. Casing erosion, if sand is being produced.

3. Potential burst on the casing at the wellhead if the well changed from oil to gas production. (Note: This should have originally been considered in the design of casing for burst but subsequent corrosion or wear may have reduced burst capacity.)

When a well is required to be worked over, the first requirement is that the well be hydraulically killed. In this type of completion, the reinstatement of a hydraulic head of fluid which provides a bottom hole pressure greater than reservoir pressure can only be accomplished by either ***squeezing*** the wellbore contents back into the formation, or circulating across the wellhead using the ***Volumetric Technique***. Squeezing large volumes of fluids back into the formation is undesirable in many cases since any rust, scale or other particulates will be lodged in the perforation or formation matrix. Thus killing such wells will result in a compromise between safety and subsequent productivity. In addition, in most squeeze operations, the required injection pressures would increase as fluids are reinjected and this may cause concern over casing burst limitations. For the large diameter casing, the heavier full weight fluid may under-run the lighter hydrocarbon and inhibit the squeeze process.

For the majority of wells, either the productivity does not merit the use of such large annular diameters or the difficulties in well killing are significant and hence the application of this type of completion is limited to areas of very high well productivities. However it can be a fairly reliable completion with a long life and minimal major workover requirements in view of its very basic design, provided that it does not suffer from abrasion or corrosion of the production casing.

A variant of this approach is sometimes applied to multiple zones whereby once the borehole is drilled down through all the zones, individual tubing strings are located opposite zone, the entire borehole cemented and each tubing string perforated with orientated guns. This approach is the simplest method of completing a multi-zone borehole but the drastic nature of its design precludes workovers if problems subsequently arise. This type of completion is known as a "tubingless completion".

2.2 Casing and tubing flow

For highly productive wells where a large cross sectional area for flow is desirable, an alternative to the tubingless casing flow would be to install a production tubing and allow flow to occur up the tubing and the tubing- casing annulus. This type of completion has the very important advantage of providing a circulation capability deep in the well where reservoir fluids can be displaced to surface by an injected kill fluid of the required density to provide hydraulic overbalance on the reservoir. This capability to U-tube fluid between the annulus and the tubing removes the necessity for reinjection into the reservoir and would not require the high pressures associated with squeeze operations. Provided no erosive or corrosive compounds exist in the flow stream, this completion is very useful for high flow rate wells.

2.3 Tubing flow without annulus isolation

In situations where annular flow in a casing-string completion would result in excessive phase slippage with consequent increased flowing pressure loss and potential instability, the consideration could be given to merely closing the annulus at surface and preventing flow. However, in reservoirs where the flowing bottom hole pressure is at or below the bubble point, gas as it flows from the formation to the tubing tailpipe will migrate upwards under buoyancy forces and some gas will accumulate in the annulus. This will result in an increase in the casing head pressure at surface. Gas build up in the annulus will continue until the gas fills the annulus and it will off-load as a gas slug into the base of the tubing and be produced. This production instability will be cyclical and is referred to as ***annulus heading***.

In this type of completion the casing is exposed continuously to produced fluid with the possibilities of erosion or corrosion. This, coupled with the potential for annular heading, suggests that unless annular flow is required then the annulus should not be left open to production, despite its simple design.

2.4 Tubing flow with annular isolation

For cases where a large cross sectional area for flow is not necessary, then an open annulus can cause complications as discussed in 2.3 above. Therefore, in the majority of cases where tubing flow will take place, the annulus is normally isolated by the installation of a packer. The packer has a rubber element which when compressed or inflated will expand to fill the annulus between the tubing and the casing. The packer is normally located as close to the top of the reservoir as possible to minimise the trapped annular volume beneath the packer and hence the volume of gas which could accumulate there. However, if the packer is installed, the ability to U-tube or circulate fluid between the tubing and annulus is removed. If such a circulation capability is required then it is necessary to install a tubing component which will allow annulus communication or alternatively rely upon the ability to perforate the tubing which consequently would necessitate tubing replacement prior to the recommencement of production. In both cases, the circulation point is normally as deep in the well as possible, but above the packer.

This completion system is by far the most widely used and offers maximum well security and control.

3 COMPLETION STRING FACILITIES

For any completion string we can define a range of operations or capabilities which may be required. Some of the capabilities are considered to be essential, such as those providing operational security or safety, whilst others can provide improved performance or flexibility. However, as the degree of flexibility provided by the completion is increased, the more complex is the design process and normally a sophisticated design will result which includes a large number of string components. With the inbuilt complexity, the reliability of the completion string becomes more suspect. Thus in the majority of cases, the design process should be approached by initially identifying the minimum functional requirements and any additional options are assessed on the basis of incremental complexity versus incremental benefit. In high operating cost areas, such as the North Sea, Alaska, The Gulf of Mexico and West Africa, the primary objective is continuity of production and hence wherever possible, simple designs which offer the basic operational facilities are favoured.

3.1 Basic completion string functions and facilities

The basic facilities provided by a completion string must allow it to continue the production or injection of fluids over as long a period as possible without major intervention to conduct well repairs. Further, at all times, the design must ensure the safe operation of the well and reliably allow for its shutdown in a variety of situations. The completion string, production casing and wellhead must act as a composite pressure system which prevents formation fluids and pressure escaping from the reservoir except via the production tubing and the Xmas Tree into the surface processing facilities.

The following are considered to be the essential attributes for the majority of completion string installations:

(a) The ability to contain anticipated flowing pressure and any hydraulic pressures which may be employed in well operations and conduct fluid to surface (production) or the reservoir (injection wells) with minimal flowing pressure loss and optimal flow stability.

(b) The ability to isolate the annulus between the casing and the production tubing if flow instability is likely or it is desirable to minimise reservoir fluid contact with the production casing.

(c) The ability to affect downhole shut-in either by remote control or directly activated by changing well flowing conditions, in the event that isolation at surface is not possible.

(d) A means to communicate or circulate (selectively when required) between the annulus and the tubing.

(e) A provision for physical isolation of the tubing by the installation of a plug to allow routine isolation e.g. for pressure testing of the tubing.

The above would provide a completion string with the necessary features to allow the well to produce in a safe, controllable manner. Consider each of the functions in turn:

(a) Pressure and flow containment

The pressure communicated between the wellbore and the reservoir is contained within the production casing, production tubing, the wellhead and the surface valve closure system known as the Xmas tree. Further, if a packer is used then reservoir or injection pressure will be retained beneath the packer.

Thus, both the casing and tubing will be designed to withstand the internal pressures which could exist in the wellbore. Similarly the wellhead, from which each casing string is suspended as the well is drilled, will be rated for maximum anticipated surface pressures. Overall control of fluid production from, or injection into, the well is provided by the valve system located on top of the wellhead. This Xmas tree usually comprises an in-line valve with a backup valve to shut in the well and side outlets with valves for both choke and kill line attachment during well killing procedures.

The production casing, packer and wellhead provide a backup to contain fluids and pressures in the event of a hydraulic failure of the tubing system.

The tubing size must be selected such that well production rates are optimised and flow is stable.

(b) Annulus Isolation

The concepts of annulus heading cycle and the potential damage which can be occasioned to the production casing, mean that a method of annulus isolation is required in the majority of production wells. For injection wells, it is frequently necessary to isolate the annulus to prevent surface injection pressures being exerted on the wellhead and possibly giving rise to burst of the production casing.

This annular isolation is normally effected by installing a packer in the completion string which is lowered into the wellbore with an elastomeric element in the retracted position. At the prescribed depth, the element is set by extrusion or inflation to fill the annular space between the tubing and the annulus. To minimise the volume below the packer and the length of casing exposed to well fluids, the packer is normally set quite deep in the well.

(c) Downhole closure of the flow string

In the event that access cannot be gained to the Xmas tree to effect valve closure and stop fluid flow or because of valve failure, it is advisable, and in most cases mandatory, to have a secondary means of closure for all wells capable of natural flow to surface. The installation of a sub-surface safety valve (SSSV) will provide this emergency closure capability. The valve can be either remotely operated on a fail safe principle from surface, or will be designed to close automatically when a predetermined flow condition occurs in the well. The initiation of the closure of the latter system will depend upon a predetermined flow rate being exceeded or the flowing bottom hole pressure declining below a pre-set level.

(d) Circulation capability

In section 2.1 , the concept of using the production casing as a flow string without production tubing was discussed and one of the major limitations identified was the inability to kill the well by circulation. The alternative killing methods of squeezing or the use of the Volumetric method are not always applicable or desirable. In many cases a coiled tubing unit or snubing unit is unavailable to re-enter the tubing concentrically. Hence for the majority of completions a specific piece of equipment is installed to allow the opening and subsequent closure of a circulation port between the tubing and the annulus. This can be provided by installing one or more of the following devices:

(i) Sliding side door (SSD) or sliding sleeve (SS)
(ii) Side pocket mandrel (SPM)
(iii) Ported nipple

An alternative but more drastic approach would be to use a tubing punch, but since the circulation ports cannot be subsequently closed, it is only usually of use for circulation prior to a workover.

(e) Tubing isolation

Normally a secondary means of physical isolation will be installed. This will usually be required to supplement the downhole SSSV and also is intended to provide isolation if the well is hydraulically dead and the SSSV is to be removed. Thus the provision of this isolation is normally provided deep within the wellbore either just above or just below the packer.

The isolation can normally be provided by lowering a plug on wireline down the inside of the tubing string until it lands and locks into a wireline nipple which was incorporated into the design of the tubing string at an appropriate depth.

A basic completion is depicted in Figure 6.

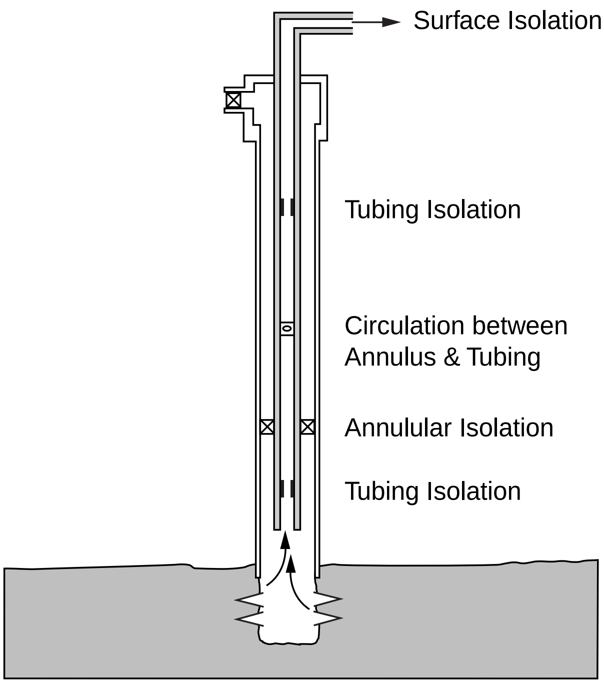


Figure 6
Basic Well Completion Schematic

3.2 Additional completion string functions

A range of other functions may be necessary or considered worthwhile for incorporation into the string design as a future contingency. Some of the more prevalent are discussed below.

(a) Downhole tubing detachment

In the event of failure of the tubing string it may be necessary to pull the completion from the well to effect replacement of completion components which are more prone to failure and require more frequent replacement. However it would be useful in a number of situations to minimise the amount of equipment which requires to be pulled from the well. Thus a point of easy detachment and reconnection would be useful. This detachment can be obtained by installing a removable locator device which seals with the rest of the tubing string to be left in the well during normal conditions but which can be pulled as required. In such cases a means of hydraulic isolation of the tubing below the point of detachment is required. Examples of this are a ***packer seal system*** which allows the tubing above the packer to be disconnected and retrieved, or a ***downhole hanger system*** which suspends the tubing in the well beneath the wellhead. Completion components which are more prone to failure and require frequent replacement, e.g. SSSV, will be located above such devices.

(b) Tubing stresses

During the normal cycle of well operations, the tubing string can extend or contract in length due to variations in both pressure and temperature subsurface. Since the string is normally landed off in the wellhead and in contact downhole with the casing through the packer, if the amount of movement were severe, it would give rise to damage to the packer, wellhead or the tubing itself.

A moving seal system could be installed which would allow expansion and/or contraction of the tubing without mechanical failure or disengagement from the packer or seal bore. Various systems are available; however, they all feature a concentric sleeve approach where seals are located in the concentric annulus and one of these sleeves is stationary.

(c) Ability to suspend P & T monitoring equipment

It is frequently required to monitor the bottomhole pressure during production tests and, in such cases, the requirement will exist to be able to run and install at a specific location in the tubing a pressure or temperature gauge. This is normally accommodated by the installation of a wireline nipple as a component of the completion string. Its location is normally as deep in the well as possible.

(d) Controlled fluid injection from the annulus into tubing

Produced fluids can contain corrosive components such as CO_2, or have high pour points with attendant flowing pressure loss problems. In such cases, it may be necessary to introduce specific chemicals into the flow string at a location deep within the well to provide maximum benefit and counteract the impact of these characteristics. Examples of this may be the injection of a corrosion inhibitor or pour point depressant. In such cases one option would be to inject these fluids into the casing-tubing annulus and by incorporating a side pocket mandrel with a valve which will open under prescribed pressure conditions, the treatment fluid will then flow from the annulus into the tubing either continuously or intermittently.

Another example of this type of requirement, would be gas lift installations, where it is necessary to inject gas into the produced fluids to lighten the hydrostatic head and maintain production at economic levels

(e) Downhole pump system

The selection of a downhole pumping system, whether it be electrical or hydraulically powered, will require the inclusion of the pump in the completion string design. Important design issues will be:

1) the method of installation and retrieval of the pump upon failure
2) constraints on access to the tubing or wellbore beneath the pump

(f) Wireline entry guide

It will be necessary, in most wells, to conduct wireline or coiled tubing operations below the bottom of the tubing string, eg across the perforated interval. In such cases, whilst retrieving the wireline tool string, assistance must be given to guide the tools back into the lower end of the tail pipe of the tubing string.

3.3. Composite completion string

It is clear that since the completion string design is influenced by a range of reservoir and other parameters, many different designs exist and in reality, for each specific situation, a number of designs can be considered. In most cases a generalised completion can be considered as shown in Fig 7. Here an attempt has been made to depict a completion string from top to bottom by identifying the components and functions.

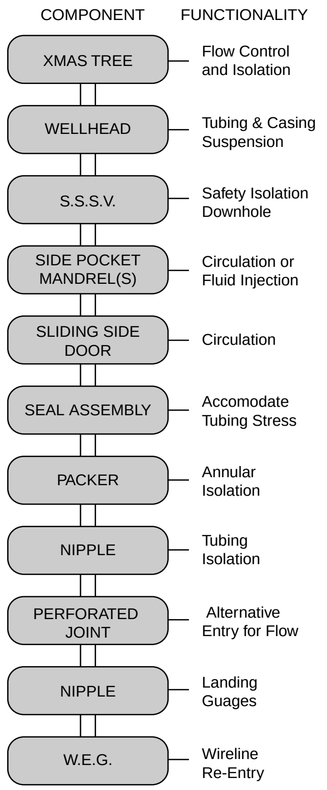


Figure 7
General Well Completion String

4. COMPLETION STRING COMPONENTS

The design of the completion string involves the selection and specification of all the component parts of the string. There must be literally thousands of potential components available if one considers that there are numerous components and variants and, further, each of the equipment suppliers has their own particular designs. It therefore is easy to understand how this part of design process can be somewhat bewildering to the les experienced. As with all services, the alternatives are usually narrowed down in that the operating company has historically used one particular supplier or has considerable experience with specific types of components. Since the equipment is specified as a certain size and with a certain type of threaded coupling, tubing completion equipment is by neccesity fairly standard and comparable between different suppliers.

In selecting equipment, this should be done on the basis that the component will provide a specific facility deemed necessary to the successful performance and operation of the well under a range of operating scenarios. Each component adds undesirable complexity to the completion and this must be compensated for by the fact that it is ***necessary or provides desirable flexibility***. One approach to discussing the subject is to postulate a typical or conventional well completion string in terms of the facility that each component provides. The discussion of a particular completion could then be made by considering whether that component or facility proposed for the typical completion is required or is beneficial in this particular instance. In this way the design is justified on an "as needs" basis and the benefits of incremental complexity created by incremental flexibility can be assessed.

A typical completion was postulated in outline in Figure 6. Each component will be discussed below in relation to what is mechanically its purpose in production operations.

4.1 Wellhead/Xmas Tree

The ***wellhead*** provides the basis for the mechanical construction of the well at surface or the sea-bed. It provides for:

1) Suspension of all individual casings and tubulars, concentrically in the well

2) Ability to instal a surface closure/flow control device on top of the well namely:
   i) A blow out preventer stack whilst drilling
   ii) A Xmas tree for production or injection

3) Hydraulic access to the annuli between casing to allow cement placement and between the production casing and tubing for well circulation

The purpose of the Xmas tree is to provide valve control of the fluids produced from or injected into the well. The Xmas tree is normally flanged up to the wellhead system after running the production tubing. The wellhead provides the facility for suspending the casing strings and production tubing in the well. There are a number of basic designs for Xmas trees, one of the simplest is shown in Figure 8. Briefly, it can be seen that it comprises 2 wing valve outlets, normally one for production and the other for injection, e.g. well killing. Additionally, the third outlet provides vertical access into the tubing for wireline concentric conveyancing of wireline or coiled tubing tools. The lower valve is the master valve and it controls all hydraulic and mechanical access to the well. In some cases, the importance of this valve to well safety is so great that it is duplicated. All outlets have valves which in some cases are manually operated or in the case of sophisticated platform systems and subsea wellsare remotely controlled hydraulic valves operated from a control room.

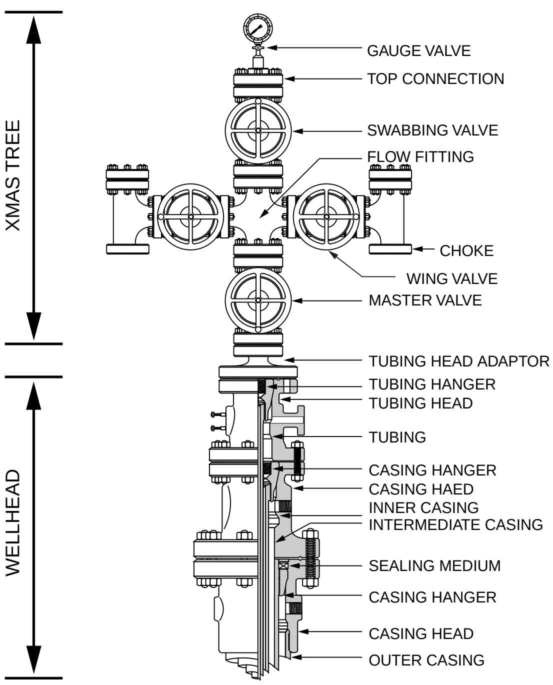


Figure 8
Simple Wellhead Assembly including Casing Spools and Xmas Tree

4.2 Production Tubing

When selecting production tubing, the following data has to be specified:

(a) The grade of steel selected for the manufacture of the tubing, e.g. N80, C75 etc. will be dependent on a number of factors such as the strength requirements for the string and, the possible presence of corrosive components such as CO_2 or H_2S.

(b) The wall thickness of the tubing referred to as a weight/foot of tubing, has to be specified and this parameter controls the tubing body's capacity to withstand tensile/compressive stresses and differences between internal and external pressures, e.g. 7" tubing is available as 26, 29, 32 lb/ft. etc.

(c) The threaded coupling is an important part of the design specification as it defines both the tensile strength and the hydraulic integrity of the completion string. The types of couplings available vary from **API standard** couplings such as Buttress BTC, Extreme Line EL, Long Threaded Coupling LTC, etc.to the specialised or ***premium*** threads commonly selected for production tubing such as Hydril, VAM, etc. These latter proprietary designs offer specific advan tages, e.g. VAM was developed for completing high pressure gas wells, where rigorous sealing and pressure integrity is difficult to achieve but essential.

4.3 Provision of an Annular Pressure Seal

In the previous discussion of completion types it was suggested that the provision of an annular seal or pack-off in production wells was necessary for one of the following reasons:

(a) To improve flow stability and production control

(b) Protection of the outer containment system/equipment such as the production casing and the wellhead.

(c) To provide the facility to select or isolate various zones during stimulation or production, e.g. to isolate two producing zones having different fluid properties, GOR, pressure or permeability (especially relevant for injection) or to stimulate or pressure maintenance.

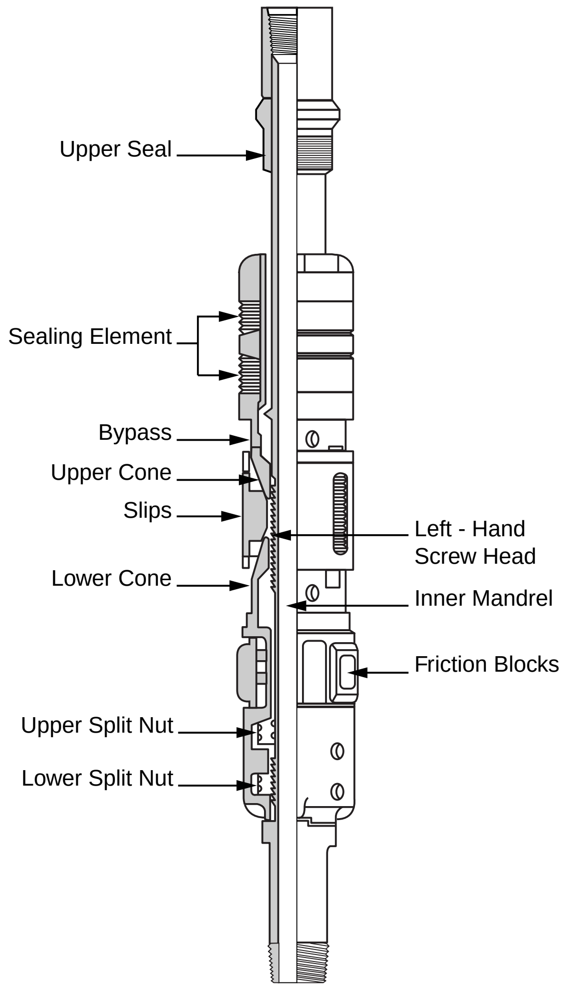


Figure 9
Major Components of a Typical Production Packer

The most common method to provide an annular seal is the use of a packer. There are numerous manufacturers, each offering a variety of designs; however, Figure 9 illustrates a basic packer. The pack-off is accomplished by expanding or extending the elastomer element outwards from the packer body until it contacts the casing wall.

There are four main characteristics which classify the various packer types:

(a) Retrievability
Here, the consideration is how easy is it to release the packer after setting. This aspect is of importance since it not only affects the degree of difficulty in working over a well, it may also reduce the applicability by introducing design limitations in terms of the differential pressure it can withstand. However, in general terms, the following categories are available:

(1) ***Retrievable Packer*** which, as its name implies, can be easily retrieved after installation. The packer can be run as an integral part of the tubing string to the setting depth where the setting mechanism is actuated.

(2) ***Permanent Packer*** which, as its name indicates, cannot be easily retrieved. It is usually run and set separately with or without the tailpipe, and the tubing string is subsequently run and engages the packer to achieve a pressure seal within the central bore of the packer. To retrieve the packer it is necessary to mill away the packer internal sleeves to allow the rubber element to collapse.

(b) Setting Mechanism

The setting of packers can be accomplished by a number of mechanisms, all of which cause compression and extrusion of the rubber element:

(1) ***Mechanically*** **-** one example of such mechanisms is rotation of the tubing string.

(2) ***Compression or Tension*** (based on suspended tubing weight). Normally, some mechanical device is required which when activated at the setting depth allows for example, string weight to be transferred to the packer to compress the rubber element. See Figure 10. These packers are simple but often unidirectional in terms of the setting force and ability to withstand a differential pressure

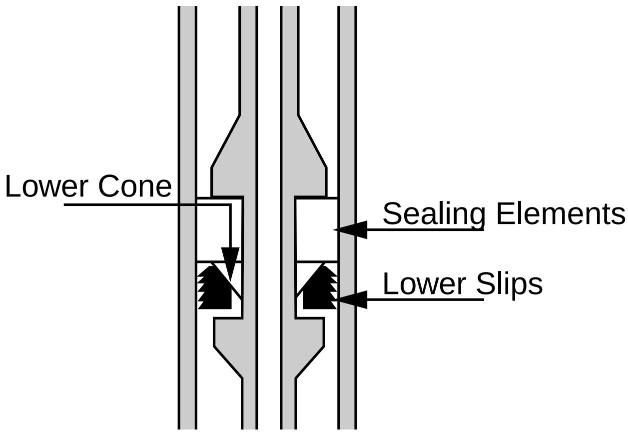


Figure 10
Schematic of a
Compression Set Packer

(3) ***Hydraulic*** **-** this mechanism utilises hydraulic pressure generated inside the completion string. By necessity, the tubing string is isolated or plugged below the packer to prevent pressure being exerted on the formation or the annulus during setting.

(4) ***Electrical*** **-** with this mechanism a special adaptor and setting tool is connected to the packer which allows the packer (plus tailpipe) assembly to be lowered into the casing on electrical conductor cable and at the required setting depth a small explosive charge can be detonated, thus actuating the setting mechanism.

(c) Ability to Withstand Differential Pressure

(1) ***Compression Packers*** (e.g. weight set) In the case of normal producing wells, higher pressure below the packer compared to above counteracts the setting mechanism. This type of packer is thus suitable for injection wells where the differential pressure supports the setting mechanism.

(2) ***Tension Packer*** This is the opposite to the compression packer and hence a higher pressure below compared to above (as in production wells) supports the setting mechanisms.

(3) ***Compression and Tension Set Packers*** These packers can withstand pressure from either direction.

(d) Packer Bore
As indicated above, it is necessary to have a bore through the packer for each tubing string. Single, dual or triple bore packers are available for multiple tubing string completions (refer to Ch. 7).

4.4 Provision of a Seal between Tubing and Packer (where necessary)
When a retrievable packer is run, it is made up as an integral component of the tubing string and the seal is effected by the tubular connection between packer and tubing.

In other cases, it is necessary to introduce a component into the tubing string which will be run into the internal packer bore and establish a pressure seal. For these applications, there are a number of options available, the designs of which depend on whether or not it is necessary to compensate for thermal expansion and contraction for the tubing string by allowing movement of the tubing to occur. The completion string is fixed mechanically by both the packer and the tubing hanger landed in the wellhead. Thus, changes in the flowing temperature and tubing pressure can cause elongation or contraction of the tubing string which may result in buckling between the packer and wellhead or tensile failure respectively. Thus, seal assemblies can be classified according to whether they allow tubular movement or not, i.e. dynamic or static seal assemblies respectively. The various types are shown schematically in Figure 11.

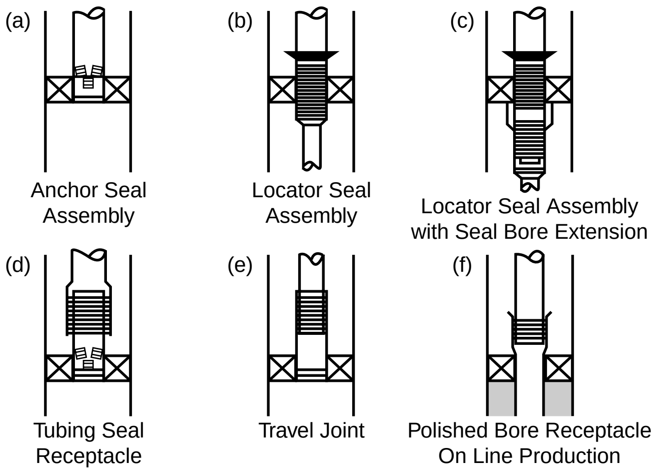


Figure 11 Schematic Views of Various Tubing Seal Assemblies

(a) **Static Seal Assembly-** no provision for Tubing Movement
In its simplest form, this is accomplished by a small tubular component which has external elastomer seal elements along its length. This component obviously does not allow for any tubing movements as contraction could easily pull it out of the sealing bore. As a precaution against this, the seal assembly is normally run with a mechanical latch assembly which lands inside the seal bore (Figure 11a).

(b) **Dynamic Seal Assemblies -** accommodate Tubing Movement

(1) ***Locator Seal Assembly*** (Figure 11b) This consists of a tubular component which has seal elements at regular intervals along its length. The length can be varied by coupling together standard sized lengths. To provide a greater seal contact area, a seal bore extension can be run with the packer (Figure 11c). The device has a shoulder at the top whose outside diameter is greater than the packer base.

(2) ***Extra Long Tubing Seal Receptacle*** (Figure 11d) This device consists of two concentric cylinders with elastomer seals between them. The outer cylinder is attached to the tubing string by a threaded coupling. The inner cylinder is latched into the packer with an anchor seal assembly as described above. The length of ELTSR is normally 10 - 30 ft but can be varied to suit the particular requirements.

(3) ***Travel Joint*** (Figure 11e) This device is very similar to the ELTSR but in its conventional running mode is like an inverted ELTSR.

(4) ***Polished Bore Receptacle PBR*** (Figure 11f). This completion component simultaneously provides both an annular pressure seal and a locator seal which permits tubing movement. The PBR consists of a receptacle with a polished internal bore normally run on top of a production liner. A seal assembly can then be run on tubing and located inside the PBR.

4.5 Sub-Surface Safety Valves

These can be sub-divided into remotely controlled and directly controlled systems. Their function is to provide remote sub-surface isolation in the event of a catastrophic failure of the Xmas tree or as a failsafe shutdown system

(a) **Remotely Controlled SSSV**

This is the more widely employed and more reliable method. The valves normally rely on hydraulic pressure, supplied to the downhole valve by a small $^1/4$" monel control line run in the annulus and strapped to the tubing, to keep the valve open. The valve itself is normally either a ball type valve (Figures 12 and 13) or a flapper device . As an alternative an electricially operated valve can be used. There are 2 options as to the method of deploying and retrieving the valve:

(1) ***Tubing retrievable*** where the valve is run as an integral part of the tubing string and can only be retrieved by pulling the tubing.

(2) ***Wireline retrievable*** where the valve nipple is run as an integral part of the tubing and the internal valve assembly can be subsequently run and retrieved on wireline cable. The valves normally open due to the hydraulic pressure acting on a piston which moves a flow tube against the ball or through the flapper. On bleeding off pressure, a spring ensures reverse movement of the piston and the flow tube, and this allows valve closure.

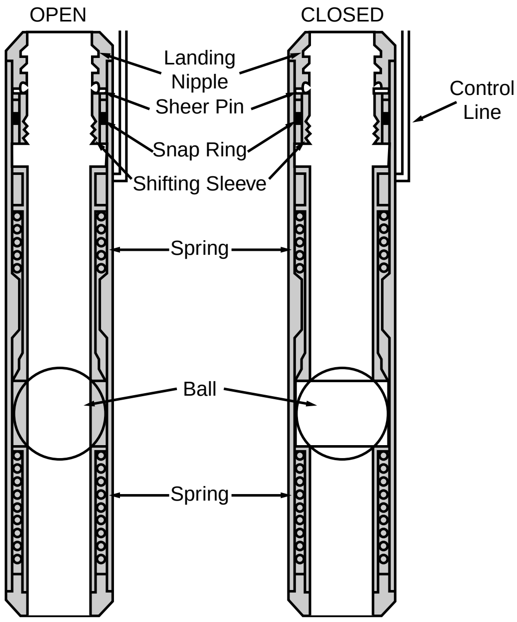


Figure 12
Remote Controlled Sub Surface Safety Valve

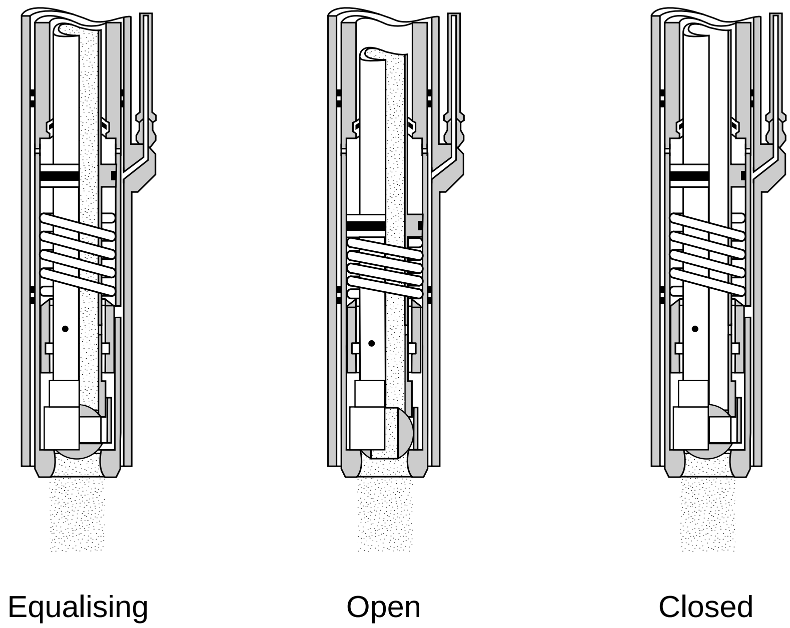


Figure 13 RCSSSV Showing Operation of the Valve

(b) Direct Controlled Sub Surface Safety Valves

This type of valve is designed to remain open provided either a preset differential pressure occurring through a fixed size orifice in the valve is not exceeded or the flowing bottomhole pressure is maintained above a preset value. Any increase in the differential pressure causes a spring to close the valve. These valves have fewer limitations on setting depth and are typically set deeper than the remotely controlled valves, e.g. in the tailpipe.

4.6 Side Pocket Mandrel (SPM)

This component, as depicted in Figure 14, contains an offcentre pocket with ports into the annulus. Using wireline or coiled tubing, a valve can be installed in the packer which allows fluid flow between tubing and annulus, e.g.:

(a) Gas Lift Valves

This type of valve when landed in the SPM responds to the pressure of gas injected into the annulus, or tubing pressure at the valve depth, to open the valve and allow gas injection into the tubing.

(b) Chemical Injection Valves

These valves allow the injection of chemicals such as corrosion inhibitors, pour point depressants, etc. The valve is again opened by annular pressure.

(c) Circulation

To allow circulation of kill fluids or the placement of a lower density fluid cushion, a valve can be installed which can be sheared by pressure allowing communication. The port can then only be reclosed by replacing the shear valve by wireline or coiled tubing.

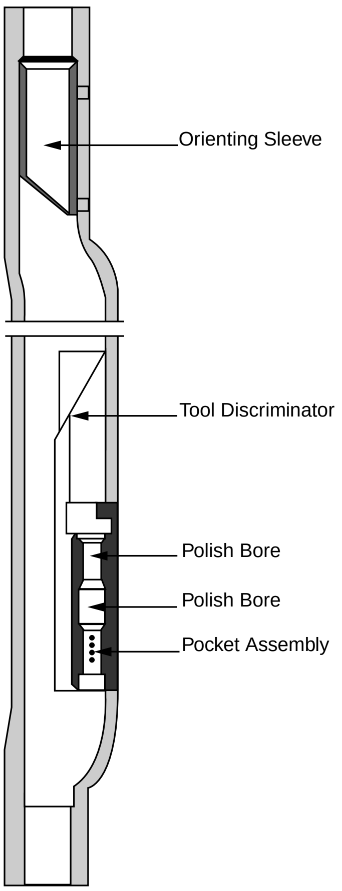


Figure 14
Side Pocket Mandrel

4.7 Sliding Side Door (SSD) (Figure 15)

This device permits communication between tubing and annulus. It consists of two concentric sleeves with elastomeric seals between them and each with slots or holes. Using wireline or coiled tubing, the inner sleeve can be moved upwards or downwards to align the openings on both sleeves. Its application is for well killing and placement of fluids in the tubing or annulus by circulation.

4.8 Landing Nipples

A landing nipple is a short tubular device which has an internally machined profile, capable of accommodating and securing a mandrel run into its bore on wireline or coiled tubing. The nipple provides a recess to mechanically lock the mandrel in place using a set of expandible keys a pressure seal against the internal bore of the nipple and the outer surface of the mandrel. Some typical nipples and mandrels are shown in Figure 16.

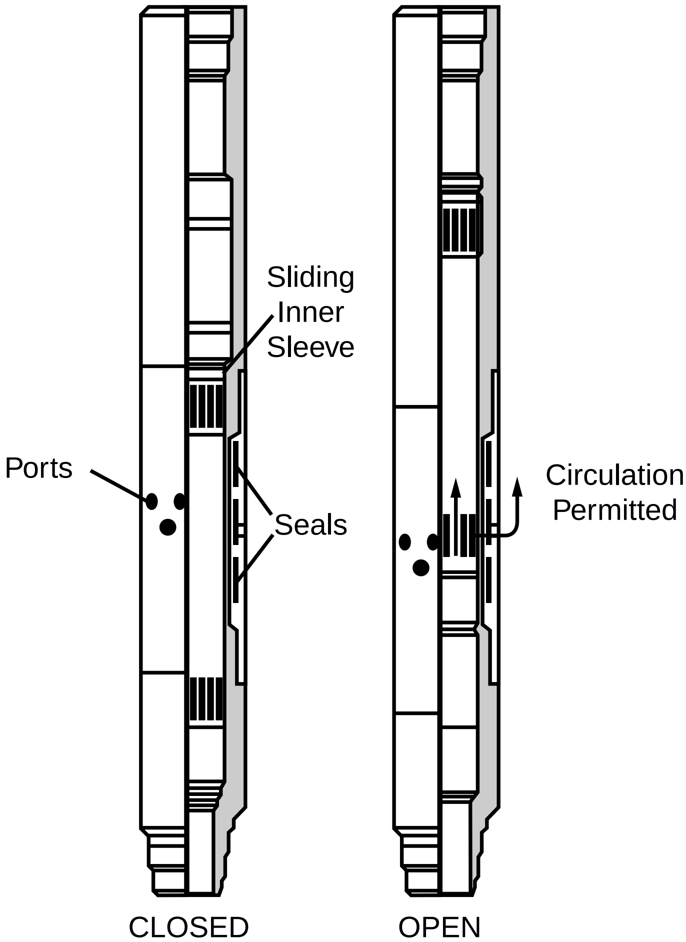


Figure 15
Wireline Operating Sliding Side Door

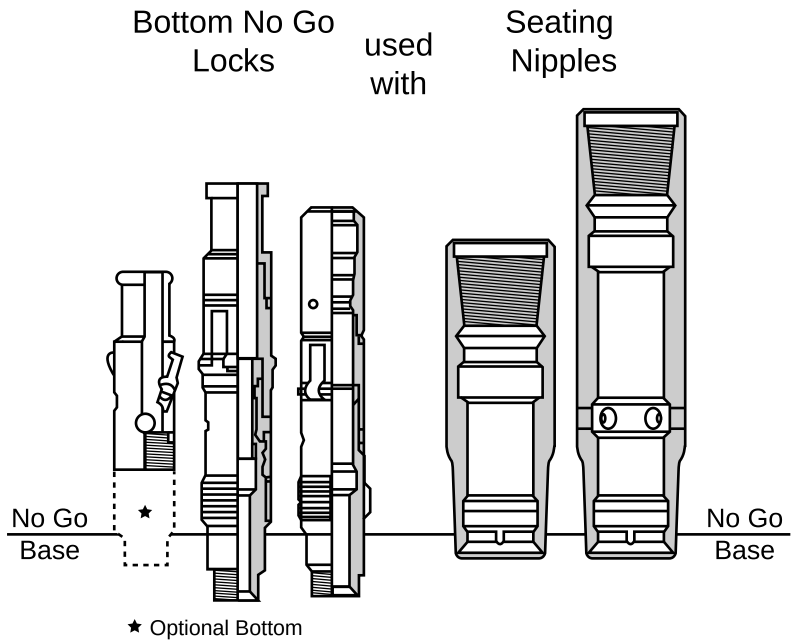


Figure 16
Wireline Nipple and Mandrel Systems

Nipples are installed at various points in the string to facilitate one or more of the following operations:

(a) Plugging the tubing for:

(i) pressure testing
(ii) setting hydraulic set packers
(iii) zonal isolation

(b) Installing flow control equipment such as:

(i) downhole chokes, regulators, SSVs, etc
(ii) landing off bottom hole pressure recorders.

Nipples can be classified into three basic designs:

(1) ***Top No-go*** where the No-go shoulder is located above the seal bore.

(2) ***Bottom No-go*** where the No-go shoulder is located below the seal bore. In this design the No-go shoulder obviously restricts the diameter of the seal bore.

(3) ***Selective Nipples*** In the above two types, the nipple sizes must progressively diminish with the depth of the string. Then it is possible to run only one of each size and type in the string. With selective nipples as required can be installed since the locking mechanism is selective and has to be specifically actuated by the wireline tool.

Nipple profiles consist of the following:

i) Lock mandrel recess profile
ii) Seal bore (below lock profile)
iii) No-go shoulder which is optional but has a minimum through bore and provides positive positioning of the lock mandrel.

4.9 Perforated Joint

This allows for flow to enter the string even if the base of the tubing string is plugged by, say, pressure gauges.

5. WELL COMPLETION DESIGNS

There are numerous well completion designs as is to be expected from the e wide range of operating areas and environments. The variety of designs which exist reflect some of the following factors:

(1) ***Well characteristics*** such as:

(a) pressure
(b) productivity or injectivity index
(c) fluid properties
(d) rock properties and geological data.

(2) ***Geographical factors***, e.g.:

(a) location
(b) water depth (if offshore)
(c) weather conditions
(d) accessibility.

(3) ***Operational design constraints***, e.g.:

(a) environmental regulations
(b) safety aspects

(4) ***The number of producing zones***.

A number of typical completion types are presented below and are subdivided into two categories, namely, land or platform type completions or subsea completions. These designs are intended to stress the functional similarities and provision in a range of well environments.

5.1 Land or Platform Based Completions

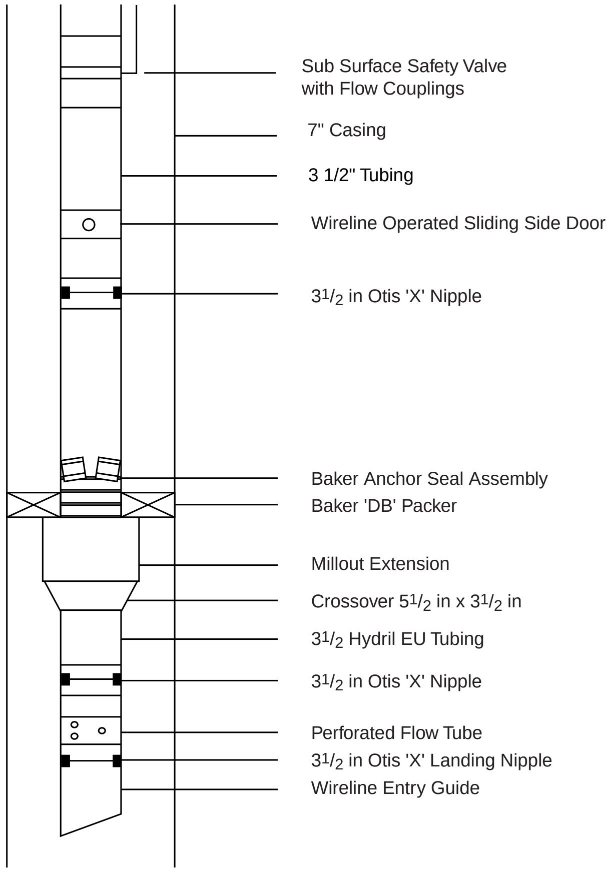


Figure 17
Single Zone Completion with no Provision forTubing Movement

COMPLETION NO. 1 (Figure 17)

This completion type features the use of VAM tubing with an anchor seal assembly latched into a permanent packer. The VAM tubing is required due to the production or injection of gas with relatively high closed in surface tubing pressures. The permanent packer would be made up with its tailpipe and run in and set on drillpipe or with electric wireline cable. The absence of a moving seal assembly infers that little expansion/contraction will occur, or that the need for good differential pressure sealing integrity is paramount.

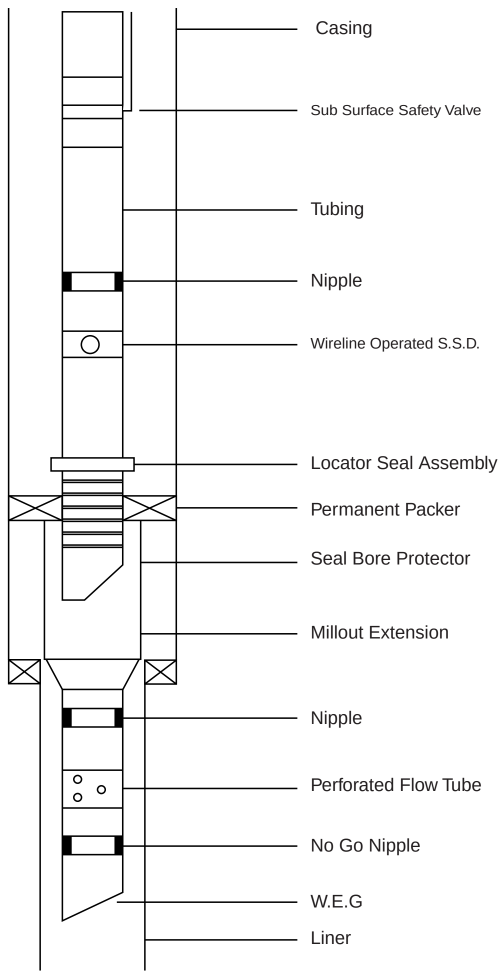


Figure 18
Single Zone Completion Utilising a Locator Seal Assembly

COMPLETION NO. 2 (Figure 18)

This design provides for production through a tubing string utilising a moving seal assembly located inside a permanent packer. Additional features include 2 nipples located in the tailpipe, the upper one for pressure isolation if the tubing string is retrieved and the lower for landing bottom hole pressure survey gauges.

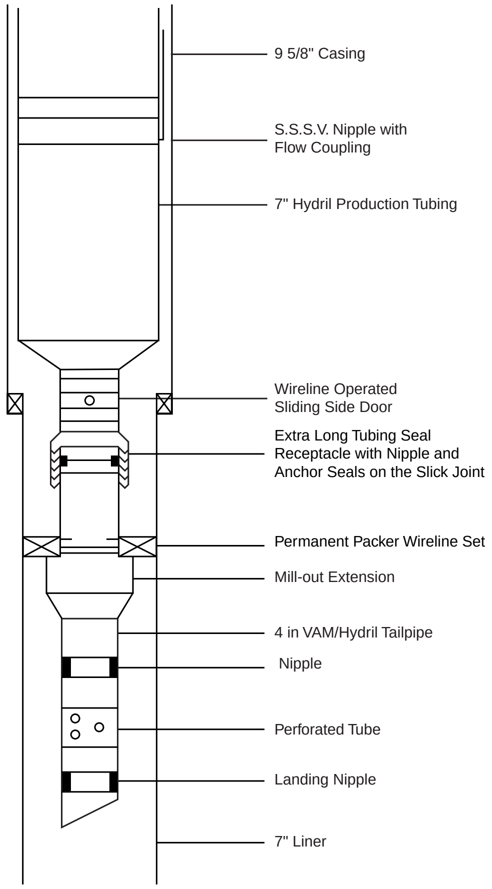


Figure 19
SingleHigh Flowrate Zone Completion Utilising an Extra Long Tubing Seal Receptacle for Tubing Movement

COMPLETION NO. 3 (Figure 19)

This design has been frequently used in high production rate areas, where its large bore tubing minimises pressure drop in the tubing. The packer and tailpipe can be set on electric cable or coiled tubing and the tubing string subsequently latched into the packer with an anchor seal assembly at the base of an extra long tubing seal receptacle ELTSR. The range of tubing movement is typically anticipated to be 5 -15 ft but depends on the range of operational temperatures. Rates of 20,000 - 30,000 bbl/d can be typical for this type of completion.

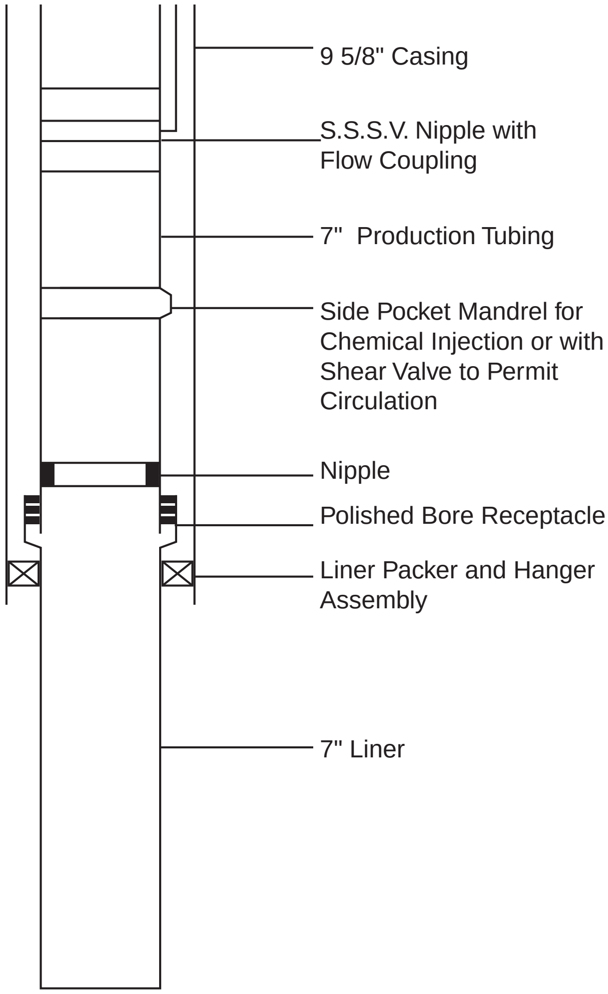


Figure 20
Single Zone High Flowrate Injection/Production Completion Utilising a Polished Bore Receptacle

COMPLETION NO. 4 (Figure 20)

This design again is specifically for high flowrate production/injection and is an alternative to Fig 19. It is referred to as a ***Monobore*** as it has a large, relatively constant diameter from surface through the reservoir and this facilitates concentric access and intervention. It utilises a ***polished bore receptacle*** at the top of the 7" liner which accepts a seal assembly at the base of the tubing string. The seal assembly provides a moving seal area to accommodate expansion and/or contraction of the tubing. This design thus offers a continuous 7" O.D. conduit for flow from the wellhead to the perforations. As shown here, there is no facility for isolating below the PBR but this can be achieved if the well is completed below the PBR with a packer and small tailpipe containing a wireline nipple to accept a plug or more reliably by running a thru-tubing bridge plug. Circulation to kill the well is preferred using a shear valve in a side pocket mandrel instead of a sliding side door.

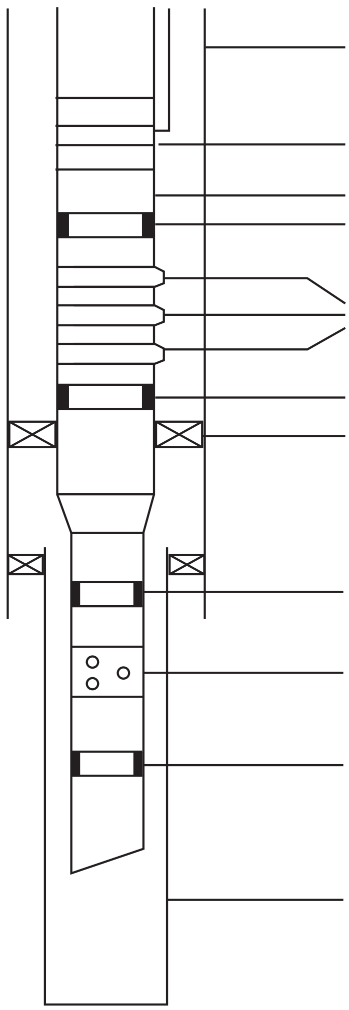


Figure 21
Single Zone Completion
Utilising a Gas Lift Facility

COMPLETION NO. 5 (Figure 21)

This illustrates a completion which utilises gas lift to allow production to occur or to increase production rates. The string comprises several side pocket mandrels containing injection valves at various depths which are designed to open and allow gas to enter the tubing from the annulus. The design utilises a retrievable packer which is preferable if it is suspected that a completion will require mechanical repair at frequent intervals, e.g. to replace non-operating gas lift valves.

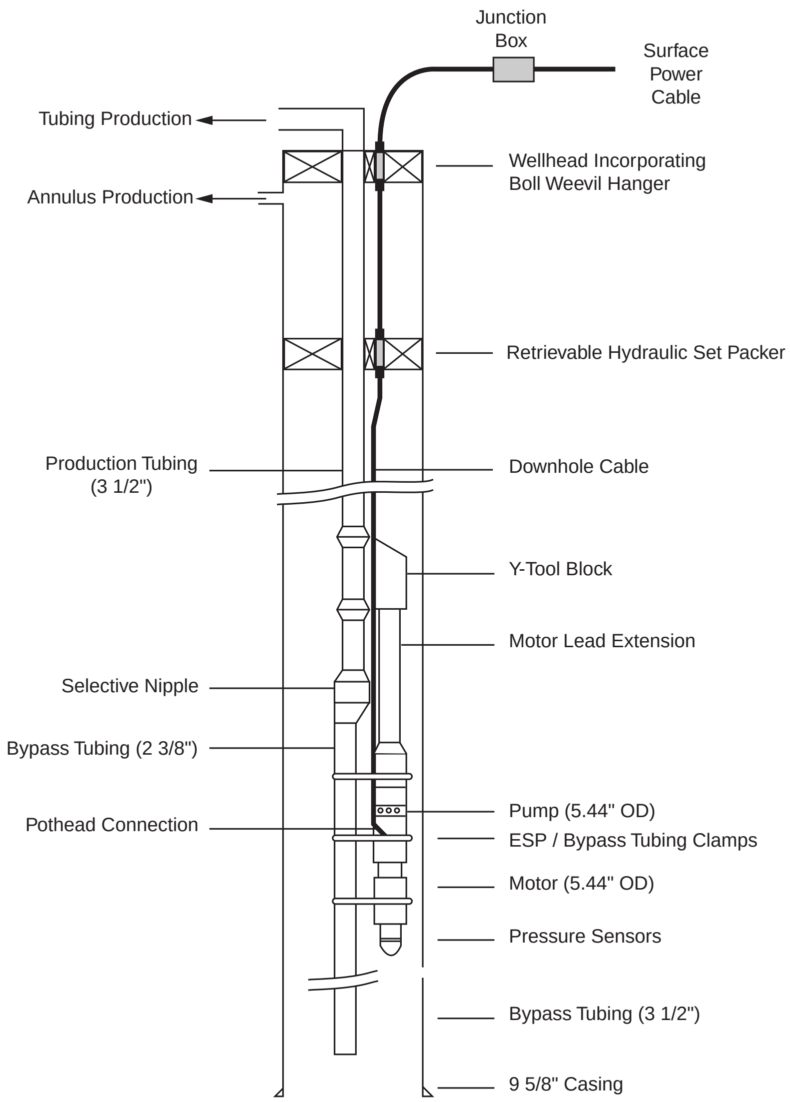


Figure 22
Single Zone Completion
Utilising an lectriccaly
Powered Submersile Pump

COMPLETION NO. 6 (Figure 22)

Here the reservoir may have insufficient pressure to lift the crude to surface or the crude may be too viscous or possess a low pour point and thus assisted flow is required. The design features a downhole electrically operated pump in a side leg tailpipe. The advantage of locating the pump in the side leg is to allow access to the producing zone below the tailpipe, say for production logging surveys, etc. Note that a retrievable hydraulic set packer is used which reduces the difficulties in pulling the string should the pump need replacing regularly – typical run life for a large capacity ESP is currently 1-3 years, but this depends upon installation efficiency and the actual operating environment.

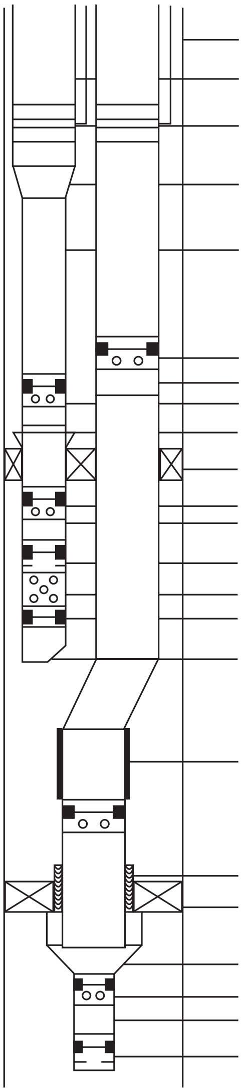


Figure 23
Dual Completion allowing Segregated Production

COMPLETION NO. 7 (Figure 23)

This completion utilises two tubing strings allowing separated production from each zone with a significant degree or reservoir management. The lower packer is a permanent packer and the longer tubing string is connected to it using a seal assembly. The upper packer is a retrievable dual packer. All equipment is duplicated, e.g. 2 sub-surface safety valves, 2 circulating devices, etc. To combat erosion on the longer string at the point of entry of fluid from the upper zone into the wellbore, thick walled joints known as “Blast Joints” are used. This design can be extended to 3 strings with 3 packers allowing for production from 3 zones or, if production occurs up the annulus, from 4 zones. However such a well is not overly common because of its high degree of mechanical complexity.

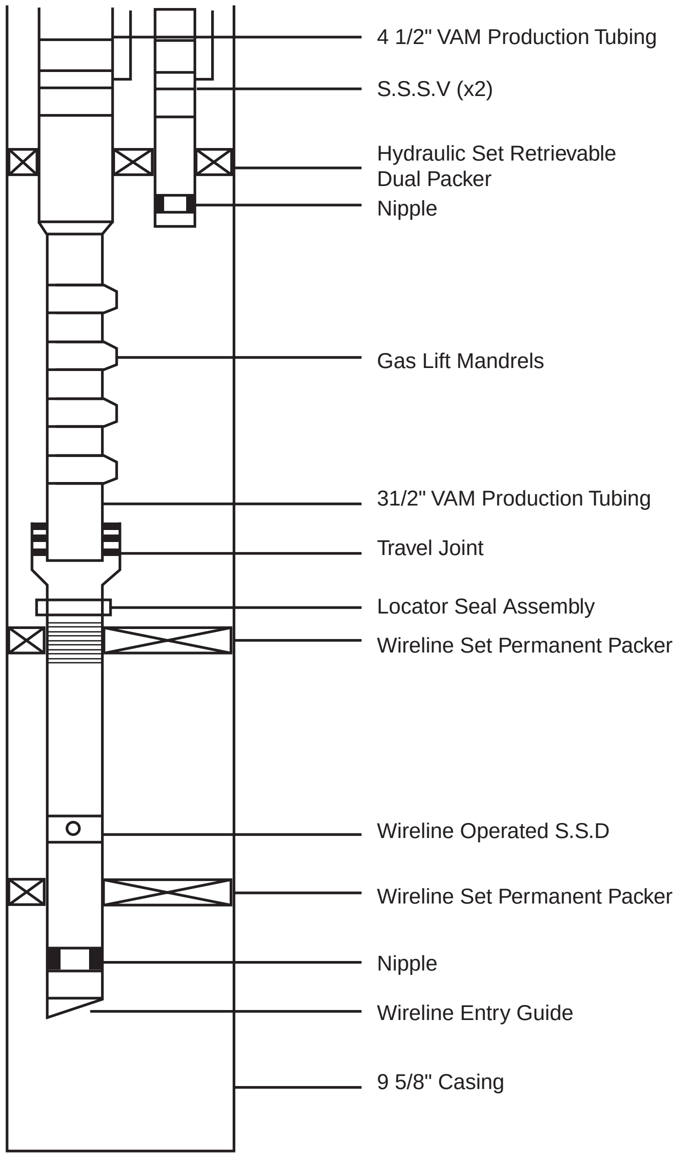


Figure 24
Selective Dual Zone Producer with optional Gas Lift Facility

COMPLETION NO. 8 (Figure 24)

This complex design introduces flexibility into the completion since it allows for selective production from either or both of the zones with continuous gas lift using gas injected down a separate string or for concurrent production of both zones using the two tubing strings. In this design, the gas is injected using the tubing to avoid excessive gas pressures being exerted on the production casing, which can be especially serious at surface with the possibility of casing burst if the casing has deteriorated.

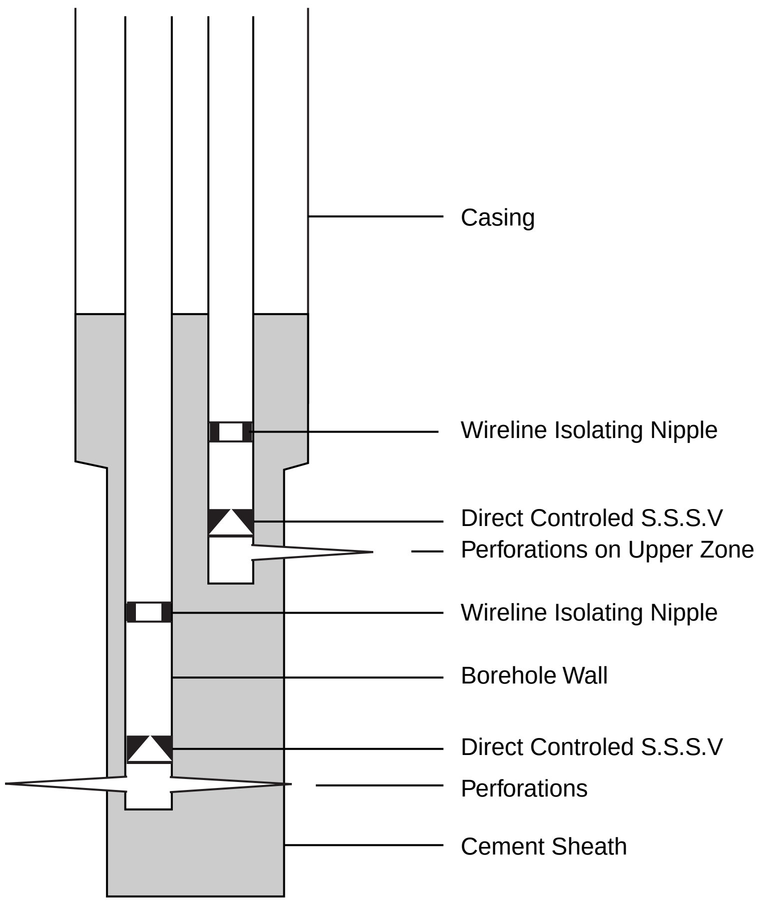


Figure 25
A "Tubingless" Dual Completion

COMPLETION NO. 9 (Figure 25)

Although the title of this type of completion is somewhat of a misnomer, it offers advantages in both cost and simplicity over the previous completions but potentially suffers from some basic limitations as discussed earlier. However, this type of completion has been applied in some areas, for example, the Middle East and the USA. It can either take the form of a single, dual or a triple completion.

5.2 SUBSEA COMPLETIONS

The following two tubular completion designs, illustrate two different philosophies for the servicing of subsea completions. Obviously some of the facilities and tubular components incorporated in the previous completions can be incorporated into subsea completions. The over-riding design philosophy is based on the high cost of well intervention and thus requires minimal planned (Figure 27) or facilitated (Figure 26) intervention.

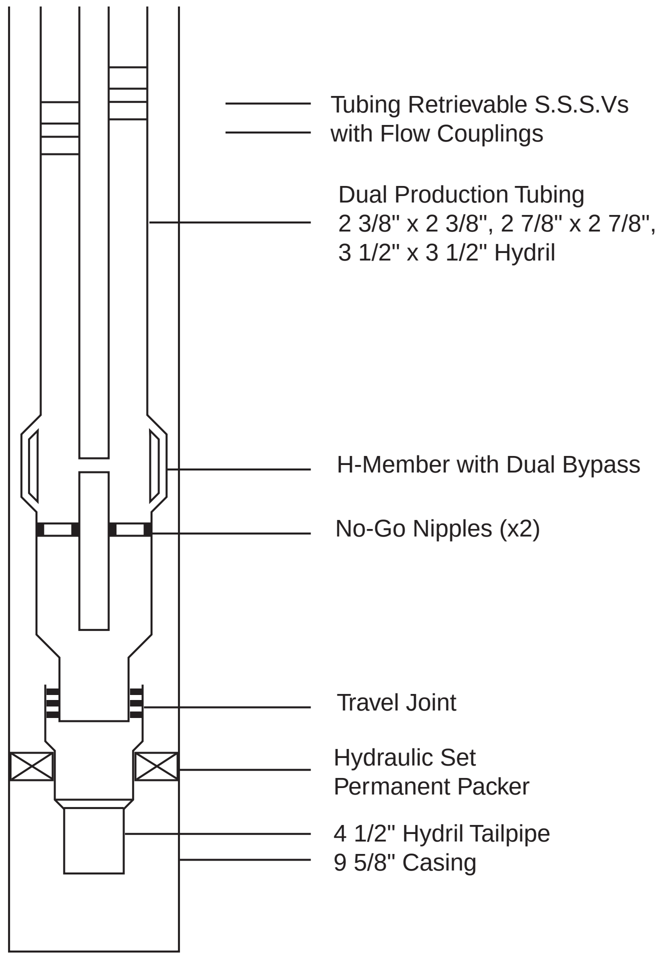


Figure 26
Subsea Completion Serviced by Through Flowline Techniques (TFL)

COMPLETION NO. 10 (Figure 26)

Serviced by the through flowline techniques TFL (pump down)

In this design, routine operations such as setting plugs, downhole valve (even perforating), etc. can be accomplished by displacing the required tools down the tubing by pumping fluid behind the tool string. By necessity, an H member and second tubing is required to allow for the flow of displaced fluid to back to the pumpdown control room and also to allow for reverse displacement for the recovery of the tools using the U-tube principle.

A well of this nature can be serviced remotely from a platform or other location using 2 production flow lines connected from the wellhead to the platform. Despite the initial capital costs, the potential benefits are that there is no necessity to mobilise a work boat or semi-submersible to carry out minor repairs and operations over the well. Currently few new TFL completions are being installed due to the development of more economical subsea wireline/CT intervention techniques.

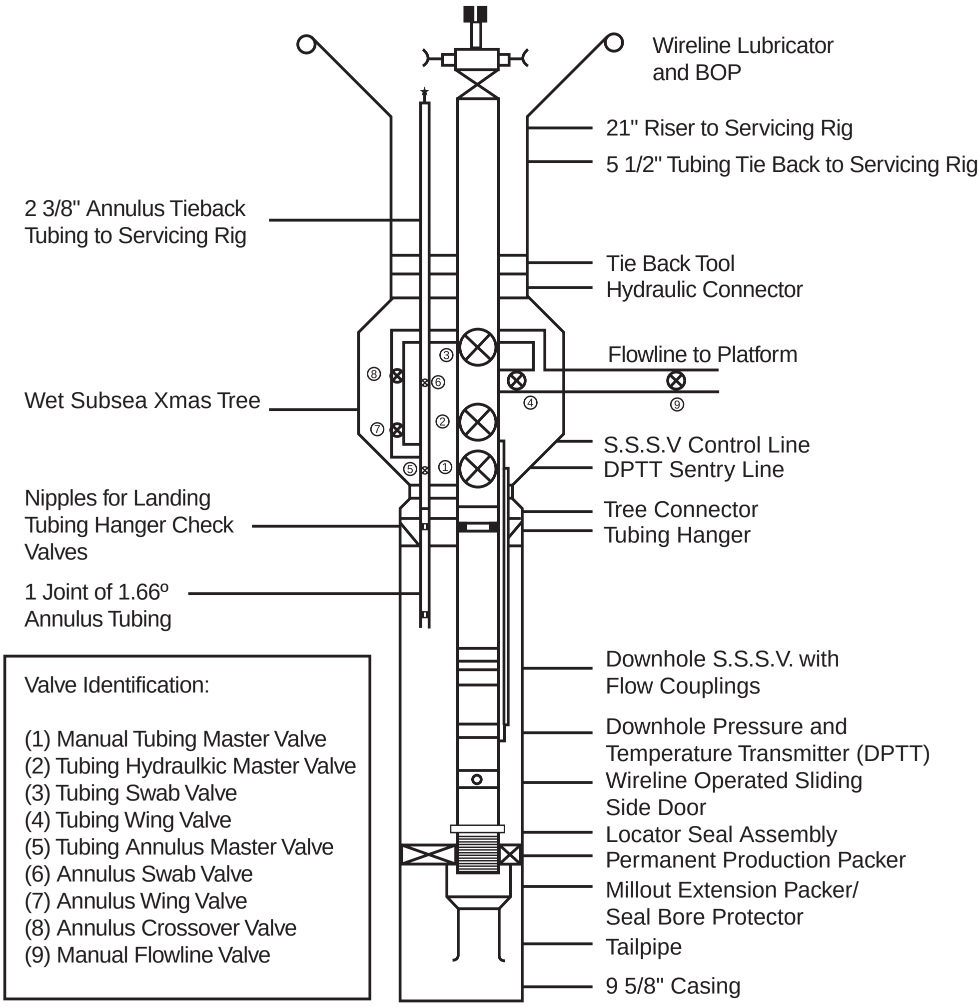


Figure 27
Subsea Completion Serviced by Conventional Wireline Techniques from a Workboat or Mobile Drilling Rig

COMPLETION NO. 11 (Figure 27)

Serviced by conventional wireline techniques

The philosophy behind this completion is to improve the reliability of the completion such that even though wireline techniques are to be used, the necessity for such work is minimised. This is partly accomplished by using a simple completion design and by duplicating essential items such as Xmas tree control valves. Although the initial capital costs for TFL facility are not required, should work be required, a work boat or drilling rig, e.g. a semi submersible or drillship, has to be mobilised.

Summary

In this chapter we have covered the basic principles of well completion design. Emphasis has been placed on:-

• Selection of the most appropriate bottom hole completion design for a specific production or injection scenario. This is primarily influenced by lost, life of well and reservoir management considerations.

• Selection of the conduit for production or injection giving regard to well integrity and longevity.

• Specification of completion string components based upon their operational function ability. The basic approach which has been recommended stresses simplicity but attempting to focus on operational efficiency throughout the envisaged life of the well.

• The purpose and need for :-
Annulus isolation
Annular tubing circulation
Subsurface safety system
Surface control and isolation
Flow and pressure isolation
Downhole monitoring accommodating L downhole tubular stress.

• General concepts of completion architecture.

CONTENTS

LEARNING OBJECTIVES:

Having worked through this chapter the Student will be able to:

- Describe the mechanisms of a slick wireline operation.
- List and describe the commonly used downhole wireline equipment and tools.
- List and describe the surface wireline equipment requirements; lubricator; BOP; stuffing box.
- Describe well pressure control and safety issues associated with wireline.
- State the limitations on successful wireline operation imposed by depth, hole angle and dog leg severity

INTRODUCTION

The majority of well completions utilise one or more of the technique of downhole wireline. Wireline can be used to accomplish the following:-

(1) the installation of completion equipment prior to running the production tubing e.g. a packer and optionally a tailpipe assembly.

(2) the installation (and retrieval) of equipment within the tubing string e.g. valves, pressure gauges, etc

(3) the operation of downhole tubular equipment to either divert or shut off fluid flow

(4) the removal of materials which can build up in the tubing string such as wax or sand.

In short, wireline can be used to accomplish a variety of tasks both in the wellbore and the completion string. These tasks can either be to operate equipment or eliminate the necessity to pull the completion string to replace certain key components when a malfunction occurs.

The principle of downhole wireline is that of lowering a tool to perform a specific function, as part of a tool string on either a single strand wire or a braided cable, down the inside of the tubing string. Manipulation of the tool string either by raising or lowering will impart a jarring effect on the tool and hence activate the setting or retrieval mechanism.

Given the relative simplicity of wireline, in many cases it will be a quicker and more economical alternative to pulling the tubing string to replace faulty equipment. However, since wireline must be capable of being used deep in the well, the operator is physically very remote from the location at which the tool is to operate. This remoteness, when coupled with the uncertainty of cable stretch especially in deviated wells and the small scale of the tools, make wireline a technique which requires highly skilled personnel to ensure its effectiveness. However, when wireline techniques can be successfully employed and are incorporated into the completion string design, they provide a significant degree of flexibility in terms of well operations and servicing capability.

The capabilities offered by wireline are numerous and a few are identified below:-

(1) Isolation of the formation by setting a plug in a wireline nipple in the tubing string.

(2) Operation of sliding side doors to allow annulus communication or to isolate zones in multi-zone selective completions.

(3) Installation and retrieval of subsurface safety valves (S.S.S.V.), downhole chokes and regulators.

(4) The ability to run in, land off and retrieve downhole pressure and temperature gauges.

(5) The installation and retrieval of valves in side pocket mandrel systems.

(6) Removal of wax from the inside walls of tubing and tubular component by scraping.

(7) Removal of sand and produced solids from the wellbore sump or above a restriction.

(8) Installation of through tubing bridge plugs to isolate zones or in well abandonment operations.

(9) Using electrical conductor cable, packers can be run with or without a tail pipe and set in the wellbore.

However, perhaps the greatest asset of downhole wireline is the ability to conduct these operations on a live well i.e. one where communication between the reservoir and the wellbore and tubing head pressure may exist.

1 SURFACE EQUIPMENT FOR WIRELINE

To enable downhole wireline operations to be performed, equipment must be provided at surface to allow the following:-

(a) the lowering and retrieval of the tool string to the work location.

(b) monitoring of tool position and cable tension.

(c) handling and alignment pulleys so that the tool string can be positioned vertically above the well for lowering through the Xmas tree and into the tubing string.

(d) the ability to insert the tool string into the live well and to prevent pressure from escaping.

(e) a blowout preventor which will seal off the annulus around the cable and if required cut the wireline.

The components of a conventional wireline system is shown in figure 1.

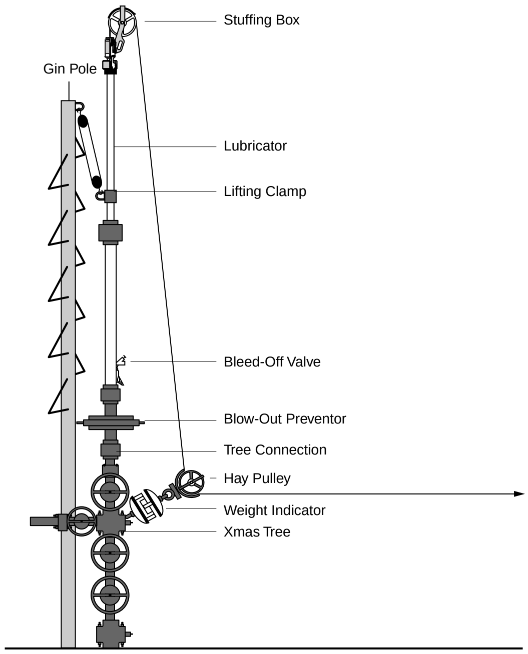


Figure 1
Surface Equipment Requirements for Wireline Operations

1.1 Wireline

Conventional wireline or "slick wireline" as it is frequently referred to, utilises a single strand high tensile wire. The wire is normally made from high tensile steel so that the ratio of breaking strength (in lbs) to wire diameter (inches) can be maximised. This will normally allow the minimum diameter of cable to be used, which is desirable for the following reasons:-

(1) it reduces the total weight of the wireline itself.

(2) it is more pliable and can be bent over smaller diameter sheaves and drum reels.

(3) it minimises the upwards pressure force on the tool string due to the difference in plain end areas at the top and bottom of the tool string.

A variety of wireline sizes are available and some are shown in table 1. Normally 50% of the maximum breaking strength is used as a working limit. In some environments where H_5S may be present, the high tensile steel will be very susceptible to hydrogen embrittlement and it may be necessary to add an additional safety factor, limit the period of use, or alternatively use low tensile steels with a lower breaking strength.

In cases where a higher breaking strength is required it is possible to use braided cables which are available in sizes of 1/8", 9/64", 3/16" and 1/4". However, it is more difficult to create a continuously effective high pressure seal around a braided cable because of its construction.

Single strand wireline is available in a range of lengths: 10000, 12000, 15000, 18000, 20000 and 25000 ft.

The wireline is normally wound onto a reel on a self contained skid which has its own power supply for drum rotation and creating cable tension.

Wire Line Type	Size (in)	Tensile (Psi)	Breaking Strength Min. (lbs)	Torsions in 8 in.	Weight/ 100 ft. (lbs)
Bright Steel	.082	234.000	1239	26	17.93
(Improved Plow Steel/ Carbon Steel)	.092	232.000	1547	23	22.58
API Wire	.105	237.000	2050		29.00
Monitor AA	.082	276.000	1460	20	17.93
(Extra Improved Plow	.0932-	275.000	1830	17	22.58
Steel/Improved	.105	280.00	2420		29.00
Carbon Steel)	.108	280.000	2561		
AISI 304	.082	240.000	1280	3	17.85
Super Tensile	.092	240.000	1582	3	22.62
	.105	240.000	2070	3	30.24
AISI 304	.082	290.000	2100		17.875
Ultra Tensile	.092			3	22.62
	.105				30.24
AISI 316	.082	210.000	1110	3	17.85
Super Tensile	.092	210.000	1390	3	22.62
	.105	210.000	1810	3	30.24
	.108	210.000	1920	3	
8-18-2	.082	190.000	1000		17.85
Super Tensile	.092	190.000	1280	3	22.62
	.105	190.000	1645		30.24
	.108	190.000	1740		

Table 1
Wireline Data

1.2 Monitoring Equipment

Given the remoteness of the operator from the tool string suspended on the wireline downhole, the important parameters during the operation will be the tool string location, or depth in the well, and the tension on the cable.

The length of cable used and accordingly the depth of the tool string with reference to a datum point e.g. the tubing hanger in the wellhead, is measured by allowing the cable to be held without slippage against a hardened wheel or odometer.

The cable tension is continuously monitored to ensure that the breaking strength of the cable is not exceeded. The cable tension will also be reduced as tool string is lowered through restriction in the tubing string due to fluid pressure and hence to a limited extent cable tension can also be used as an approximate indication of tool position.

1.3 Alignment pulley system

In view of the length and rigidity of the tool string it is necessary for the cable to be passed across a double sheave system which first of all changes the orientation of the cable from the horizontal to the vertical plane and secondly changes the orientation by 180° to lower the tool string into the well as shown in fig. 1. The pulleys are selected to provide the minimum bending stress on the wireline during use.

1.4 Tool string insertion under well pressure

To allow the tool string to be inserted into a live well, it is necessary to attach to the Xmas tree, above the swab valve, a pressure tube known as a lubricator into which the tool string can be inserted and lowered down the well through the Xmas tree. Once the lubricator has been aligned vertically above the Xmas tree and coupled to it using a quick release, high pressure coupling, the swab valve can be opened to allow the well to pressurise the lubricator. To prevent well pressure escaping from the top of the lubricator above where the wireline is installed, the wire must be passed through a wireline stuffing box. The assembly is depicted in figure 2. Attached to the top of the stuffing box unit is the upper sheave which redirects the wireline through 180°. The wireline passes through the top of the stuffing box, through a series of washer type packing units and culminates in a knot within a rope socket inside the lubricator (Fig. 3). The rope socket has a female threaded section at its base to which the tool string can be attached.

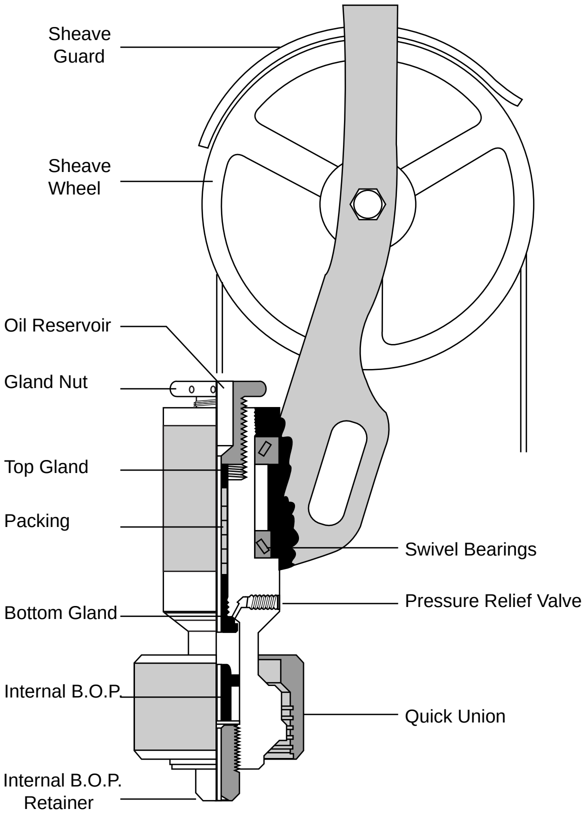


Figure 2
Wireline Lubricator Stuffing Box

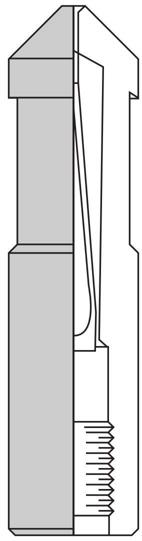


Figure 3
Wireline Rope Socket

The length of the lubricator can be varied since the lubricator can be obtained in sections which can be screwed together to give the required length. The lubricator is available for working pressures up to 15000 psi and diameters ranging from 2 5/8" to 5 1/8" for standard or sour (H_2S) service.

At the base of the lubricator just above the point of attachment to the Xmas tree, it is necessary to instal a wireline B.O.P. valve. This valve can either be manually or hydraulically activated and can either be a single or dual ram unit, Figures 5 and 6 respectively. These rams are designed to close off around the wireline and retain full well pressure below the ram.

After closure, well pressure above and below the ram must be equalised through the equalising ports shown in Figures 4 and 5. Further, a vent valve on the lubricator allows the depressurisation to take place, for example, when the tool string has been recovered into the lubricator and the swab valve on the Xmas tree closed.

Normally, the packing in the stuffing box is compressed upwards and inwards around the wireline by the well pressure. However, in some cases a hydraulic packing system is utilised whereby grease is injected into a flow tube immediately beneath the stuffing box. The hydraulic pressure applied to the high viscosity grease regulates the efficiency of pressure sealing in the stuffing box.

Prior to running any tools into the well, the lubricator and wireline B.O.P. valves must be tested to the required pressure.

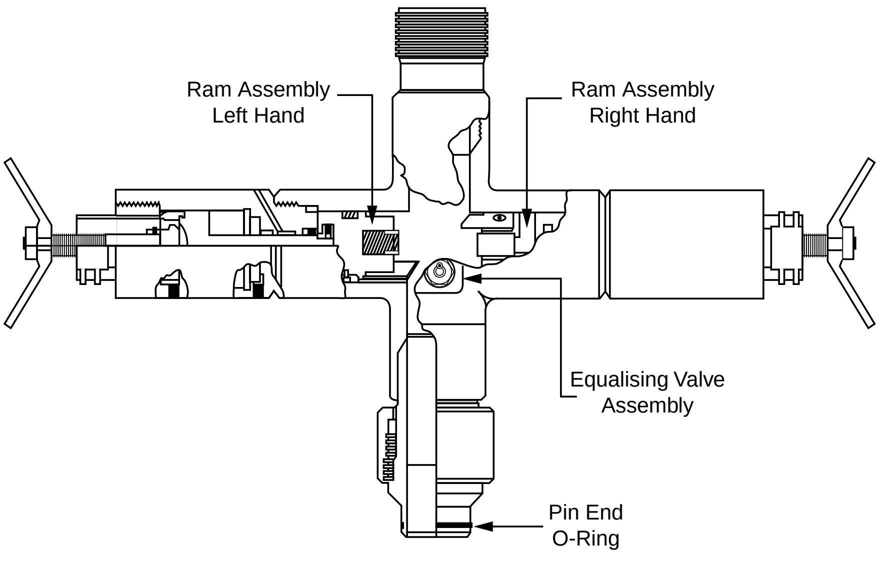


Figure 4
Single Ram Hydraulic Wireline Valve

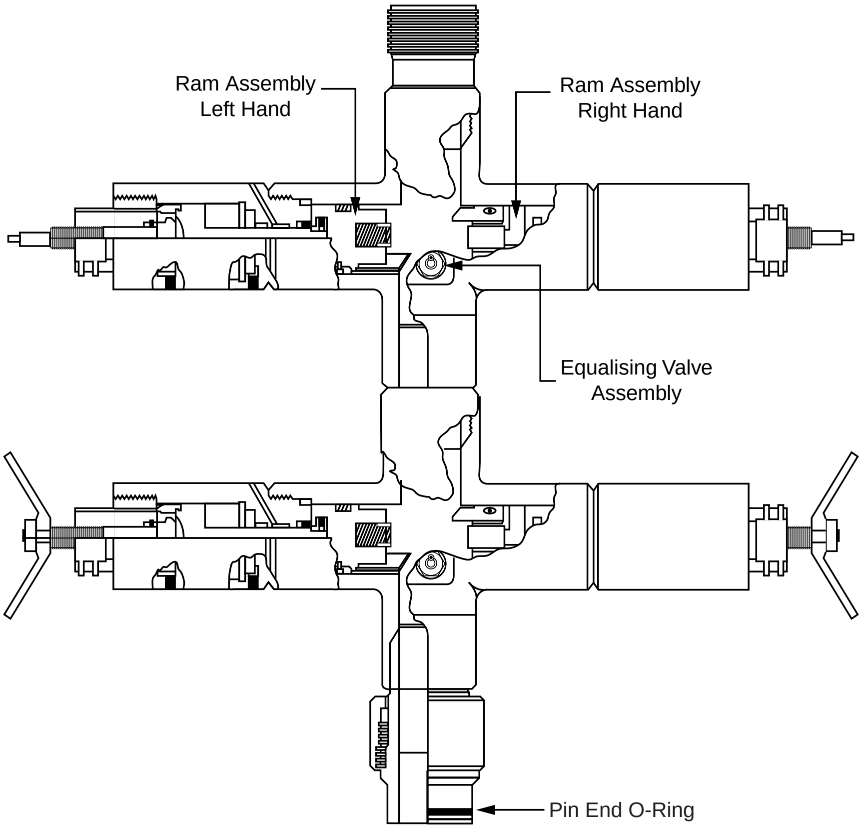


Figure 5
Dual Ram Hydraulic Wireline Valve

2 WIRELINE TOOL STRING

The tool string is attached to the rope socket at the end of the wireline. Besides connecting to the wireline, the tool string must also provide:-

(1) the ability to provide weight so that the wireline is held in tension and can be run into the well at an acceptable speed.

(2) the activity to accommodate fairly rapid changes in inclination within the tubing string particularly in deviated wellbores.

(3) the ability to provide a jolt upwards or downwards on the work tool by upwards of downwards jarring.

(4) the correct running or pulling tool to instal or retrieve the wireline component within the tubing string. Alternatively an auxiliary function tool such as a paraffin cutter may be conveyed.

A schematic of a tool string is shown in Figure 6.

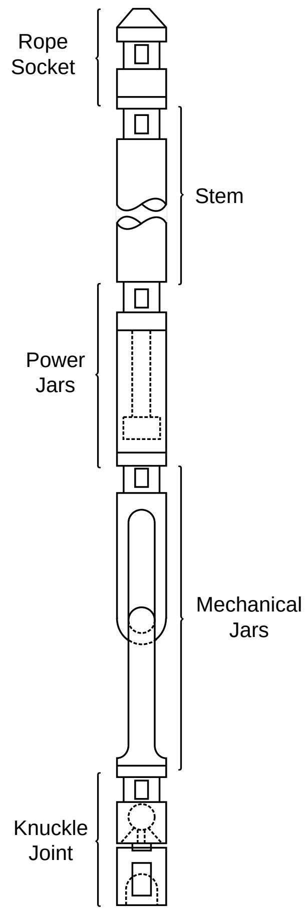


Figure 6
Schematic of Wireline Tool String

2.1 Stem

When a wireline tool string is run into the well, there are two forces which oppose the tool string:-

(1) the frictional force as the wireline is pulled downwards through the packing elements of the stuffing box.

(2) a differential force acting upwards on the tool string due to the difference in the plane end areas of the top and bottom of the tool string due to the diameter of the wireline itself. The force can be calculated as follows:

Maximum upwards force =

max. fluid pressure in the wellbore (psi) x $^{\pi}/_{4}\, d^2$

where d = nominal wireline outside diameter in inches.

Thus based upon the anticipated well pressure and the nominal diameter of the wireline, additional weight will be required to ensure tool string descent into the well and this is provided by incorporating a length of stem bar in the tool string. This is only approximate as it neglects the effect of friction in the stuffing box packing.

The stem bar is available in a range of nominal diameters from $^3/_4$" to $1^7/_8$" and in lengths of 2ft., 3ft. and 5ft. The stem bar is attached directly to the rope socket using the thread connecting system (Fig. 7).

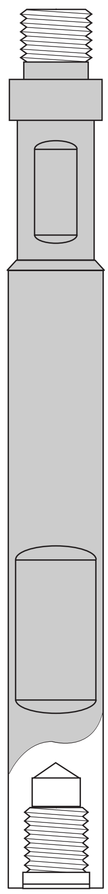


Figure 7
Stem Bar

2.2 Jars
Since the operation of all wireline equipment is affected by mechanical impact, it is essential that the tool string can deliver the weight of the stem bar as a jolt or jar to the operating tool. This is accomplished by placing a set of jars immediately below the stem. Most frequently, mechanical jars, as depicted in Fig. 9, are employed and these can be used to create a jarring force in either the upwards or downwards direction. The action is such that these jars are sometimes referred to as stroke jars.

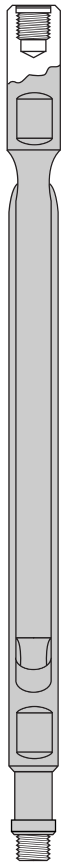
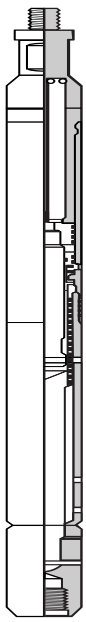


Figure 8
Mechanical Jars



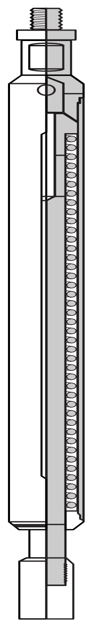


Figure 9
Hydraulic Jar (left)

Fgure 10
Accelerator (right)

In addition, it is possible to run a set of hydraulic jars immediately above the mechanical jars, but these only provide a jarring capability in the upwards direction. If hydraulic jars are used in shallow well operations an accelerator is frequently added which helps to maintain a steady pull on the hydraulic jar as it starts to open, Fig. 10.

2.3 Knuckle Joint

The knuckle joint is a ball and socket joint which is run above the operating tool and helps to align it with the tubing string, Fig. 11. The alignment is critical, to assist in the centralisation of the operating tool in, for example, the nipple prior to its installation by jarring downwards.

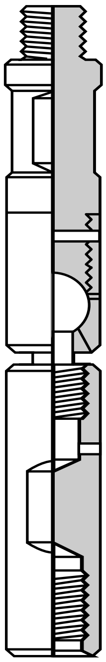


Figure 11
Knuckle Joint

At the base of the wireline tool string will be located the operating or service tool which will perform the required function.

3 WIRELINE OPERATING TOOLS

A wide variety of tools exist, some of which are general in nature and simple in design whilst others are highly specific in both design and function.

3.1 Gauge cutter

Prior to conducting any specific wireline operation in the well it is good practice to run the tool string into the well with a gauge cutter on the end to the prescribed depth. This will determine:-

(1) if the tool string will have passage down the inside of the tubing.

(2) the top of individual landing nipples of specific sizes.

Gauge cutters are available for all tubing sizes up to 7" nominal diameter.

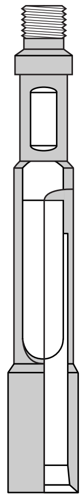


Figure 12
Gauge Cutter

3.2 Swage

If a minor obstruction is encountered in the tubing, then a swage can be lowered on the tool string and used as a mash to open tubing or clear the obstruction.

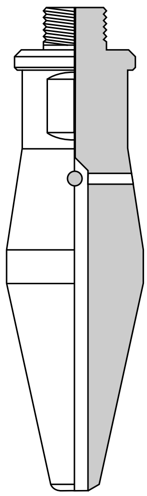


Figure 13
Swage

3.3 Impression tool
All wireline mandrels and tools are designed with a fishing neck on top, so that if the wireline breaks, hopefully at the rope socket as intended, then a fishing operating with an overshot should latch on to the tool and allow its retrieval from the well. However, it will be necessary, prior to commencing a fishing operation, to establish the condition and position of any obstruction on the top of the fish. A lead impression block has a lead filled core at its base and when lowered on to the fish will provide an imprint of the physical condition of the top of the fish.

3.4 Wireline spear
The wireline in normally expected to break at the rope socket during normal failure such that the wireline itself can be pulled from the hole. In the event that the wireline breaks at a different location, the wire may form a 'birds nest' in the tubing which will need to be removed by a grapple known as a wireline spear, Fig. 14.

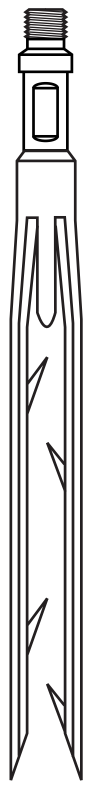


Figure 14
Wireline Spear (left)

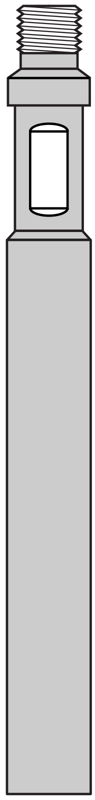


Figure 15
Blind Box (right)

3.5 Blind box

In operations where the tool string is required to jar down onto a fish or obstruction, a blind box can be used at the base of the tool string, Fig. 15.

3.6 Wireline bailer

The build up of solid deposits e.g. sand in the wellbore or perhaps the deposition of solids on top of a tubular component such as a mandrel, may necessitate the use of bailers. Particularly in the latter case it may be necessary to remove the solids prior to gaining access to the pulling neck of the mandrel.

A bailer can be run on a wireline tool string. Two general types are available, the first is operated by jarring up and down on a piston bailer which acts to suck sand into the bailer. The other design known as a hydraulic bailer, comprises a chamber at atmospheric pressure, a shear disc and non-return ball valve. Downwards jarring on the solids will shear the disc and the solids will be sucked up into the low pressure chamber.

3.7 Tubing perforator

In cases where the facility to circulate between the annulus and the tubing is either non existent or inoperable, it is possible to run a tubing perforator on a wireline tubing string. The tubing punch can be used in both standard and heavy weight tubings and is available in sizes from 1 1/4" nominal dia. to 5" nominal dia. Again the punch is activated by jarring.

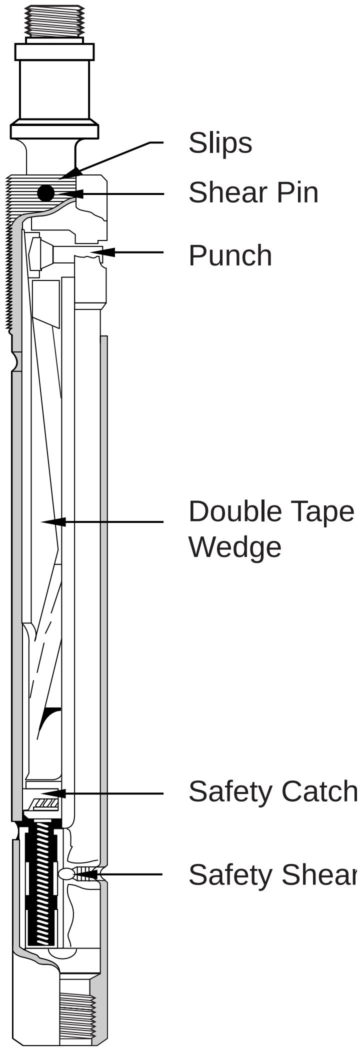


Figure 16
Type 'A' Otis Tubing Perforator

3.8 Positioning tools

The design of a sliding door, or sliding sleeve, incorporates two concentric sleeves with seals between them, both sleeves having either ports or slots which, when aligned, provides a communication path between the annulus and the tubing. The operation of this device requires running a positioning tool on a tool string which will engage into a recess in the inner sleeve. Jarring upwards or downwards will move the inner sleeve to the required position and hence operate the device, Fig. 17.

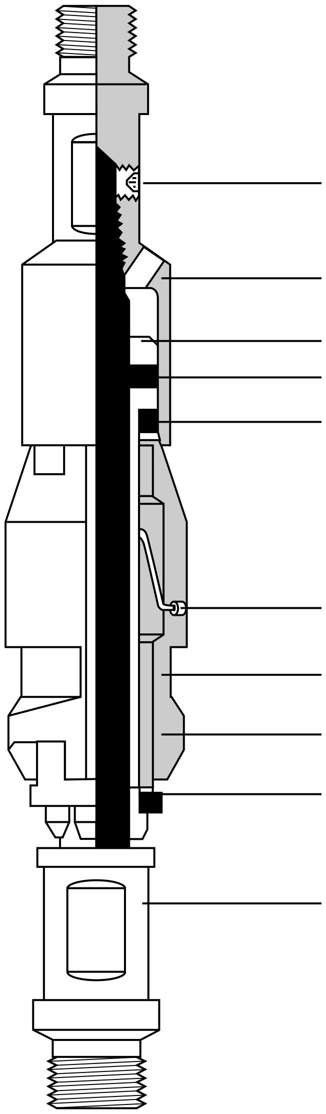


Figure 17
Type 'B' Otis (Halliburton) Positioning Tool

3.9 Running Tools

A running tool is required to run and set a mandrel into the corresponding wireline nipple. It is attached to the base of the tool string with the wireline mandrel attached beneath it. The system is lowered into the required nipple position and by jarring, the collets on the mandrel are released and expand outwards into the recess profile in the base of the nipple. The mandrel is locked in place within the nipple. Further jarring will allow the running tool to release from the mandrel, Fig. 18. These running tools are available in sizes from $1^7/_8$" dia. up to just under 6".

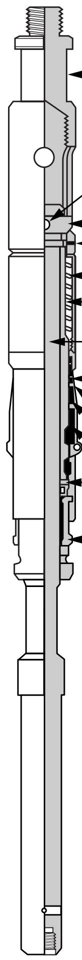


Figure 18
Type 'X' Otis (Halliburton) Running Tool

3.10 Pulling tools

The mandrel when mechanically locked within the nipple will also provide a pressure seal due to the seals in the seal bore between the internal seal bore of the nipple and the OD of the mandrel. In a number of cases, a pressure differential across the mandrel may exist prior to its removal e.g. if a subsurface safety valve or plug has been installed. To remove the mandrel it will be necessary to run a pulling tool on a tool string down on to the pulling neck of the mandrel. Jarring will allow the collets on the mandrel to retract once differential pressure across the mandrel has been equalised and the packing elements are relaxed. The pulling tool can be designed to operate either with upwards, e.g. the Otis/Halliburton ‘GR’, or downwards jarring, e.g. the Otis/ Halliburton ‘GS’ pulling tool, Fig. 19.

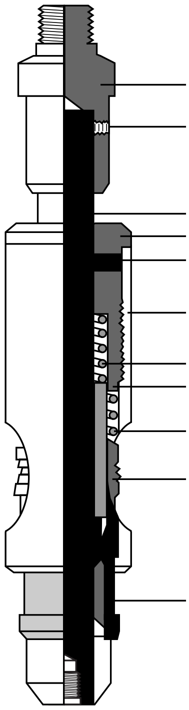


Figure 19
Type 'GS' Pulling Tool

Summary

In this module you have been introduced to the practice of slick wireline. Key points in a review of the material include:-

• The importance of safety and efficient well control throughout the operation achieved by the lubricator, stuffing box and BOP.

• Wireline operation are constrained by hole angle and along hole length in addition to the mechanical strength capacity of the wireline.

• Tool operation is controlled solely by jarring or applying a hammer blow upwards or downwards.

• Wireline operations can be used in through tubing or casing operations.

• The technique allows retrieval, replacement or operation of a range of reservoir management or monitoring tools.

CONTENTS

Learning Objectives:

Having worked through this chapter the Student will be able to:

- For each of the major completion components listed below, discuss and review the main equipment options, advantages and disadvantages:

  Tubing for production / injection
  Wellheads
  Xmas trees
  Packers
  Seal assemblies
  Subsurface safety valves
  Nipple profiles
  Flow control and circulation devices

- Specify metallurgy recommended for a range of operating condition.

- Evaluate force balance across packers.

- Select a packer for a design load condition.

1 PRODUCTION TUBING

The bulk of the completion string comprises threaded joints of tubing which are coupled together. The integrity of the tubing is vital to the safe operation of a production or injection well. The specification of a production tubing must be carried out based upon the mechanical and hydraulic operating conditions envisaged, the proposed operating environment and "life of well" considerations. The tubing must be specified to provide the following capabilities:

(1) The inside diameter of the tubing must provide a produced fluid velocity to minimise the total pressure loss as defined by the tubing performance relationship.

(2) The tensile strength of the string of made up tubing must be high enough to allow suspension of all the joints to the production zone without tensile failure occurring of any of the joints above.

(3) The completion string must be able to withstand high internal pressures as a result of fluid flow entry into the tubing.

(4) The completion string must be able to withstand high external differential pressures between the annulus and the tubing.

(5) The tubing must be resistant to chemical corrosion which may arise because of fluid contact in the wellbore, and might ultimately accelerate string failure by one of the loads and stresses mentioned above (2)-(4).

Each of the above facets of tubing selection are discussed below.

1.1 Tubing Diameter

Conventionally the outside diameter of the tubing is specified. The inside diameter is defined by the wall thickness of the steel through the weight per feet of the tubing (lbs/ft). The decision as to the wall thickness to be used will influence the tensile strength of the steel as well as its resistance to failure with high internal or external pressure differentials. The tubing is thus specified as being of a certain outside diameter and of a specific “weight/foot” which thus specifies the wall thickness

e.g. 41/2" O.D. x 13.5 lbs/ft or, say, 7" O.D. x 26 lbs/ft.

1.2 Tensile Strength

The tensile load that can be tolerated by a joint of tubing without the occurrence of failure is determined by the tensile strength of the steel specified for the tubing, the wall thickness of the tubing (and hence the “plain end area”) and the tensile strength of the threaded coupling. Normally the tensile load tolerable without failure of the threaded coupling, greatly exceeds that of the tubing wall or pipe body itself.

There are several grades of steel considered as standards by the API, namely H-40, J-55, C-75, L-80, N-80 and P-105. The numbers after the letter grading signify the minimum yield strength in units of a thousand psi. The letter grades indicate the manufacturing process or subsequent treatment of the steel to modify its properties, e.g. the C and L grades are heat treated to remove martensitic steels which will thus lower their susceptibility to H_2S adsorption and subsequent sulphide stress cracking/ hydrogen embrittlement and consequent failure. Thus the C-75 and L-80 grades are useful in some environments. In general the higher the yield strength created by working the steel, the more susceptible it would be to embrittlement and failure, if it comes into contact with even small H_2S concentrations.

The minimum yield strength defines the minimum tensile strength in psi. However, since the tensile load is taken by the plain end area or wall section area of the pipe, the weight/foot of the pipe will also affect the tolerable tensile load. Since each joint suspends the joint immediately beneath it, the design on the basis of tensile load will require an increasing tensile strength in the joints nearest surface.

The other aspect of tensile strength, although normally not the limiting one, is the type of threaded coupling. The threaded coupling provides a female connection at the top of each joint which will mate with a pin or male screw connector at the base of the joint immediately above it. The threaded coupling has to provide two basic functions; firstly to transmit tensile load up the tubing string and secondly to produce a connection which provides a seal to retain internal pressure within the tubing.

The design of a completion string to withstand a given tensile load will obviously be dependent upon the depth to which the completion string will be run but the following aspects will also be considered.

(a) The minimum tensile strength of the pipe utilised for the design will be based upon the manufacturers data or API specification but will be reduced by the application of a safety factor which will normally have a value in the range of 1.6 to 2.0.

(b) The effect of tensile load on a suspended string will be to cause elongation of the string with a subsequent reduction in the plain end area or wall thickness and this will have to be taken into account when considering the possibility of failure due to high external pressures by derating the nominal collapse resistance. This is done by application of the Biaxial Stress Theorem.

1.3 Internal Pressure

Since the tubing string is designed to convey the fluids to surface it must be capable of withstanding the anticipated internal pressures. However, it is not the magnitude of internal pressure which is important but rather the magnitude of differential pressure by which the internal exceeds the external pressure. This condition is referred as “burst” and the limiting condition is usually encountered at surface where the external pressure is at its minimum. The level of burst pressure to be tolerated is normally defined on the assumption that the string is gas filled, i.e. the tubing head pressure (T.H.P.) equals the reservoir pressure minus the hydrostatic head of gas in the well.

In tubing design the A.P.I. figures are derated by a safety factor which varies from 1.0 to 1.33.

1.4 External Pressure

The burst condition referred to above is reversed if the external pressure exceeds the internal pressure and this is defined as being a potential collapse condition. This condition is prevalent at the position of maximum pressure on the outside of the tubing in the annulus. Collapse is therefore most likely to occur deeper in the well.

In calculating the collapse condition the criteria for collapse are defined using the published minimum collapse data with the application of a safety factor of 1.0 to 1.125 and derating the calculated values to account for tensile load.

1.5 Corrosion

There are two principal types of corrosion encountered in oil and gas production wells namely:

(1) Acidic Corrosion - due to the presence of carbonic acid (from CO_2), or organic acids within the produced hydrocarbon fluid.

(2) Sulphide Stress Cracking/Hydrogen Embrittlement - due to the presence of H_2S in the flowing well fluids from the reservoir. H_2S can also be generated by the growth and subsequent action of sulphate reducing bacteria in stagnant fluids, e.g. in the casing-tubing annulus.

Since most corrosion is selective, e.g. pitting, an even reduction in wall thickness due to corrosion will not normally occur and no allowance on wall thickness can be made initially to compensate for corrosion. Corrosion inhibitor treatments will assist in minimising corrosion damage due to acidic compounds. For low partial pressures of H_2S, the procedure is to recommend a reasonably low grade steel since these are less susceptible to embrittlement, e.g. C 75 or N-80.

1.6 Coupling Types

There are two general classes of threaded coupling:

(1) Connections which require internal pressure to produce a pressure tight seal - API regular couplings.

This type of coupling includes the API round thread and buttress connection whereby a thread compound applied to the threads must be compressed by external pressure acting on the coupling causing it to fill any void spaces within the coupling.

(2) Metal to metal or elastomeric seal connection - Premium threads.

This class of coupling includes the Extreme Line as well as a range of specialised couplings of specific commercial design, e.g. Hydril or VAM designs. The couplings do not always utilise the threads to give the pressure seal but allow torque to be applied to bring together seal shoulders or tapered surface within the coupling.

In other specialised couplings, resilient seal rings are also used to provide an additional seal system.

Coupling can also be classified as being ***Integral*** or ***External*** couplings. An external coupling such as the VAM coupling shown in figure 1 below requires that a male thread be cut on each end of the tubing joints and that a female: female coupling be screwed onto one of the male threads. The external coupling features a larger effective wall thickness in the coupling section giving it higher load capacity compared to an integral coupling. The integral coupling as shown in figure 2 has a male and female thread cut on opposite ends of the pipe.

An external upset coupling uses an increased wall thickness of pipe at one end of the pipe allowing a female thread to be cut without sacrificing too much of the tensile load carrying capacity. A flush joint is one in which there is a inform ID through the make up connection. An internal upset coupling is one in which there is a small section of increased ID in the coupling.

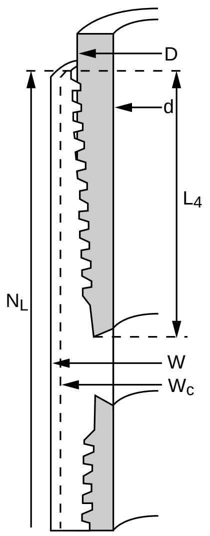


Figure 1
VAM Threaded Coupling
(external coupling)

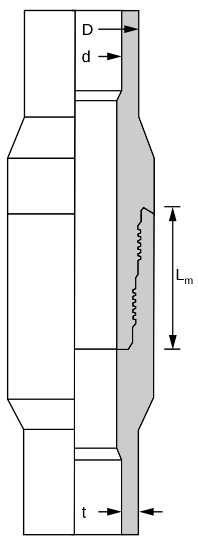


Figure 2
Hydril Tubing Coupling

1.7 Specification of Tubing

The string is defined initially by the well productivity analysis which suggests the optimum tubing ID based upon a range of available sizes. Frequently the completion string will comprise lengths of several different diameter tubings, with the diameter decreasing towards the bottom of the well. The use of larger diameter tubing higher up the well may be useful to counter the increasing flow velocities as the fluid expands and gas is liberated from solution as pressure declines up the tubing. The reduction in tubing size in the lower sections of the well may be necessary because of limited equipment availability and mechanical limitation, e.g. production liner inside diameter.

Once the size is specified, the design based upon the 3 mechanical conditions of tension, burst and collapse is undertaken.

Ultimately the design will yield a specification for a string comprising one or more types of tubing defined as follows:

Length of tubing	- tubing OD	- tubing wt/ft	- grade of steel	- coupling type	- joint length

e.g. 7000' - 51/2 - 23 lb/ft - C-75 - Hydril Super EU - Range 3

2 WELLHEAD SYSTEMS

Before describing the equipment options available for a wellhead, it is necessary to define the functions of a wellhead.

The wellhead is the basis on which the well is constructed and tubulars suspended during the drilling and completion operation. The wellhead serves three important functions:

(a) Each of the casing strings which are run, cemented and have an extension to surface or the seabed, as well as the production tubing string(s), are physically suspended within the wellhead.

(b) The wellhead provides the capability of flanging up a device to control the flow of fluid from or into the well. In the drilling phase, this flow control device is known as a blowout preventer stack (B.O.P.) and this remains in place until the production tubing string has been suspended in the well. Once the completion string is in place, the B.O.P. is removed and the production flow control system, known as the Xmas Tree, is installed on top of the wellhead.

(c) Each wellhead spool or landing area offers a flanged outlet allowing hydraulic communication into that annulus.

In this section we will limit the discussion to wellheads utilised on offshore platforms or on land based wells, i.e. for the time being subsea completions will be excluded. There are 3 basic wellhead designs in frequent use, namely:

(1) Conventional Spool System
(2) Compact Spool Systems
(3) Mud Line Suspension System

2.1 Conventional Spooled Wellheads

With this type of wellhead, the running of the conductor or surface string is performed and, a casing head housing is either screwed or welded on to the top joint of casing. The internal profile of the casing head housing provides a tapered seat from which the next casing string to be run, will be suspended. To accomplish this suspension, a hanger must be attached to the last joint of casing. The type of hanger known as a slip hanger is a wrap around type consisting of a hinged pair of semi-circular clamps with a tapered external profile which matches the tapered profile on the inside of the casing head spool or housing. This type of hanger, e.g. the Cameron A.W. hanger is only suitable for low to intermediate suspended weight. The alternative hanger is one which is circular with a tapered external profile but it is coupled to the top casing joint with a screw thread. This type of hanger is usually referred to as a “boll-weevil” hanger.

Subsequently, to accommodate sequentially each string of casing, a casing head spool has to be added to the wellhead to suspend the next string of casing to be run. The spools are either flanged or clamped together. Finally, prior to running the production tubing string, a spool known as the tubing head spool is added to the top of the upper casing head spool.

Since the annulus for each casing string must have no communication with any other annulus nor to atmosphere, it is imperative that the wellhead provide an effective pressure sealing system. The pressure sealing is achieved by creating pressure isolation by at least two of the following for each possible annulus or potential leakage area:

(1) The creation of a pressure seal between flanges so that if annular pressure exists it cannot escape from the wellhead. This is accomplished by the use of so called ring gaskets.

(2) The creation of a seal area either above or within the hanger on the tapered shoulder.

(3) If the casing projects into the base of the next casing head then a seal ring system will provide isolation in the contact area between the extended neck of the casing and the internal profile in the base of the spool.

The ring gaskets are constructed of metal and are laid into a recess on the flange faces. As the flanges are bolted together, the gasket is compressed and the seal effected. Various types of ring gasket exist, each type having a specific cross sectional shape. Gaskets exist for regular applications with a low to intermediate pressure sealing capability - the API “R” ring joint gasket, to the API type “BX” gasket for high pressure wellheads.

The system of sealing in the other wellhead areas, e.g. on the hanger seal, can be accomplished by the compression of a rubber element or by plastic injection into the seal area.

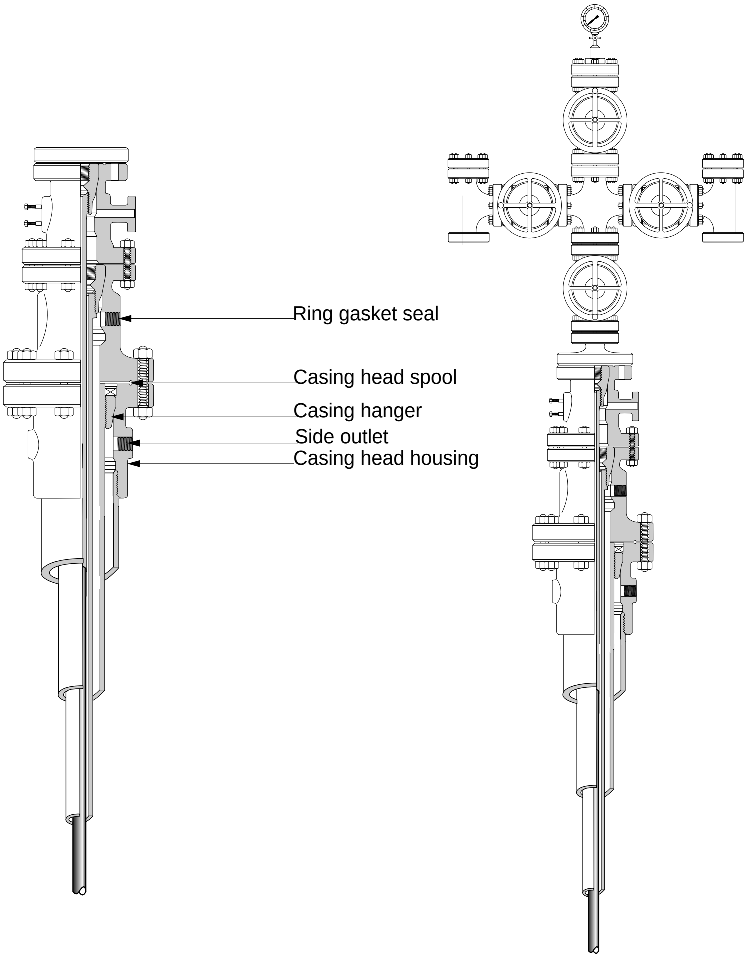


Figure 3a (left)
Wellhead
Figure 3b (right)
Simple Wellhead Assembly including Casing Spools and Xmas Tree

2.2 Compact Spool System

A disadvantage of the conventional wellhead is that for a spool to be installed at each stage of the well, the B.O.P. stack has to be removed and this is potentially hazardous for the safety of the well if ineffective primary cement job has been conducted, particularly in the lower sections of the well where zones containing hydrocarbons may be encountered at high pressure.

Most wellhead companies also offer a one piece spool which will provide the hang-off areas for the suspension of say the last 2 casing strings, e.g. 1 intermediate casing string and the production casing string, as well as the production tubing string.

Assuming that a 30" conductor has been set, the 26" hole would be drilled and subsequently the 20" casing run into the well and cemented. A casing head housing attached to the top joint of 20" casing provides internally the hang-off shoulder for the next casing, i.e. the 133/8" casing. Once the 133/8" casing is landed off and cemented, the compact spool can be flanged up on top of the 20" casing head housing the B.O.P. nippled up to the top of the compact spool. The compact spool thereafter provides the facilities to suspend either a 95/8" intermediate casing, a 75/8" production casing and the production tubing or alternatively if a production liner is run through the pay zone and not tied back to surface, a spacer/seal system is installed between the 95/8" casing hanger and the tubing hanger.

A complex system of sealing is employed as follows:

(1) A ring gasket is located on the flange face between the compact spool and the 20" casing head housing.

(2) The 133/8" hanger has seal rings both on the tapered seat which locates in the 20" casing head housing and on the extended neck of the hanger which locates in the base of the compact spool.

(3) Sealing is provided around the neck of the hangers within the spool by the injection of plastic.

(4) The tubing hanger also has seals both at the base of the hanger as well as on the extended neck which projects out of the compact spool.

During production there will be a gradual warm up of all casing strings but the possibility of this either:

(1) causing mechanical damage, or
(2) causing failure of a seal system

is minimised since the suspended weight of the subsequent casing is landed on top. However, the tubing hanger has no such weight to prevent upwards movement and would be held in place by the equipment bolted on top of the wellhead if it were not for tie down bolts. These bolts are screwed in from the wellhead body until they contact the upper tapered shoulder on the hanger thus preventing its upward movement.

The “compact spool” is the terminology used by Cameron to market their version of this wellhead whilst FMC describe their system as a UNIHEAD.

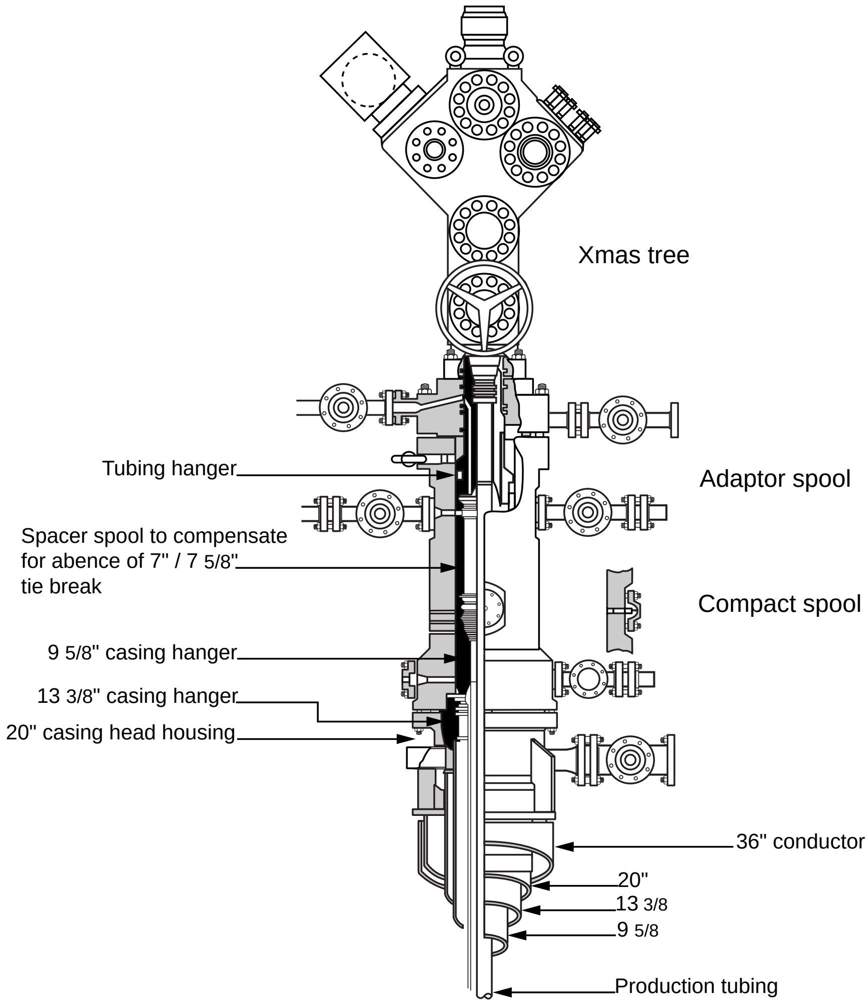


Figure 4
Compact spool with xmas tree in place.

2.3 Mud Line Suspension System

In this system the wellhead is built up on the sea bed but the production well will be completed back to the platform or production well jacket. Thus although the well will be controlled above sea level hence requiring its completion back to that point, the weight of the suspended casing strings cannot be transmitted to the jacket or platform. The two facilities required of the wellhead are therefore separated positionally in that:

(a) a wellhead built up on the seabed will be used to suspend casing strings

(b) in addition each casing will have an extension string from the seabed wellhead to a subsidiary wellhead at the platform where the BOP and subsequently the Xmas Tree will be attached.

If the well is to be completed then it can be done so either with a sea bed Xmas Tree or alternatively if a small jacket is used, above sea level. If the well is completed with a jacket then a single Xmas Tree can be installed. However, if the well is to be completed at sea bed, then the casing extensions can be removed using the running tools and retrieved. The Xmas Tree would then be clamped on to the extended neck of the 7" casing.

Alternatively, if the well is to be suspended temporarily, it can be capped after retrieving the casing string extensions from the mudline.

3. XMAS TREE

The Xmas Tree is the production flow control system and it is a system of valves which control physical or hydraulic access into the tubing string or the annulus between the production casing and tubing string (often termed the A-annulus). The access capabilities required are as follows:

(a) A capability to inject into or produce from the production tubing - access is provided through the ***flow wing valve or kill line valve.***

(b) A capability to lower into the production tubing a wireline service tool string - the vertical access is provided through the ***swab value.***

(c) A capability to completely close off the well.

The simplest type of Xmas Tree utilises a series of valves connected to each leg of a cross piece. Refer to figure 3(b). The valve located between the cross piece and the wellhead is referred to as the master gate valve and in the majority of modern well completions, especially on platforms, this valve is duplicated by the installation of one manually controlled valve and a remotely controlled valve (usually hydraulically). In addition whilst the swab valve, ie the valve at the top of the tree remains manually operated the flow wing valve for production is usually also remotely operated from a separate control room. In some instances the kill wing valves have also been installed as remote valves.

The cross piece Xmas Tree possesses one major disadvantage and that is that it contains a large number of flanges and hence a significantly increased possibility of leakage.

An alternative design of tree utilises a solid block construction of a yoke piece configuration. Figure 4. This type of tree allows overhauls to replace faulty valves or actuators.

Normally the Xmas Tree is connected by a flange or clamp to the top of the wellhead but because of incompatibility in flange sizes, an adaptor spool may be required to reduce the top flange diameter to accept the Xmas Tree. In such cases pressure sealing between the flanges is provided by ring gaskets. Pressure isolation internally is achieved by sealing between the tubing hanger and the internal bore of the Xmas Tree, adaptor flange and wellhead using elastomer seal rings.

4 PACKERS

A packer provides physical isolation of the casing/tubing(s) annulus above the production zone.

4.1 Packer Applications

Packers are an essential piece of completion equipment in a large number of wells. The reasons for their use varies from well safety considerations to production flow stability.

Some of the more common reasons for using packers are outlined below:

(1) Well Protection

Since the packer isolates the casing/tubing annulus above the production zone, it is designed to prevent the formation fluids communicating up the annulus and provides:

(a) Corrosion Protection - contact of well fluids containing H_2S, CO_2 or organic acids with the casing and outside wall of the tubing is prevented.

(b) Abrasion Protection - since no flow occurs up the annulus, abrasion due to solids such as sand entrained within the produced fluids is prevented.

(c) Casing/Wellhead Burst Protection - the elimination of reservoir pressure communication prevents the generation of high annular casing pressures at surface. e.g. In a gas well where the liquid in the annulus unloads and gas then fills the annulus and exerts a casing head pressure.

(2) Production Stability

In oil wells producing from a reservoir with a solution gas drive reservoir or where the bubble point is reached close to the perforation, the flow of a 2 phase mixture into the tubing string can lead to gas segregation and its accumulation in the annulus where its volume will gradually increase until it offloads by U-tubing up the production tubing. This phenomenon is known as an ***"annulus heading cycle".***

(3) Zonal Isolation

In wells designed to produce either up a single tubing string completed selectively over several zones or where a tubing string is provided for each zone, a packer is required to isolate between each zone to prevent comingling of production or inter-zone fluid flow.

(4) Annulus to Tubing Injection e.g. gas lift wells

In a variety of completions, fluids are injected into the annulus and the completion string is designed to allow these fluids to enter the tubing string at specific depths and at a certain flowrate. The types of fluid injected can be chemicals such as corrosion inhibitors or pour point depressants but very commonly it is gas injected to assist in the vertical lift process. In such cases, the use of a packer prevents the fluid merely U-tubing at an uncontrolled rate via the bottom of the tubing which would lead to ineffective production of hydrocarbon.

(5) Injection Operations

In injection operations such as water or gas reinjection, or stimulation operations such as fracturing, the use of high surface pressures is necessary either to generate an economic injection rate or to exceed the fracture initiation pressure. Without the use of a packer, these pressures would be communicated up the annulus and might cause concern regarding the burst criteria for the casing/wellhead.

(6) Temporary Isolation

In some cases it is necessary to provide some degree of protection across the production zone to prevent the loss of fluid into the reservoir from a higher density fluid in the wellbore during workover operations and well closures. In such cases running a bridge plug - a type of full bore packer capable of being run down through the tubing, and setting it just above the perforations would provide zonal isolation and protection.

4.2 Basic Packer Components and Mechanics

A typical packer figure 5 comprises the following components:

(a) Sealing Element(s)

The isolation of the annulus is normally provided by the extrusion of the sealing element by some form of axial compression, such that it fills the annulus at the packer between the completion string and the casing. The sealing element consists of one or more rings of elastomer or combination of elastomers. Obviously the material of construction of the sealing element must be able to withstand the anticipated conditions in the wellbore with regard to pressure, temperature and chemical composition of the fluids likely to exist in the wellbore. For example, in H_2S or CO_2 conditions, Teflon or Viton seals would be specified.

Baker packers usually utilise a single element whilst Otis packers frequently use a system of 3 elements.

Since the element is exposed to high pressures and temperatures for all its service life in the extruded state, it will suffer degradation. The Otis-favoured system of 3 sealing elements is designed such that the upper and lower seal rings are of a harder composition and are thus able to restrict the extrusion of the centre element. The softer central element will seal on any surface imperfections.

In addition, to provide a mechanical barrier to prevent excessive extrusion and hence element failure, most packers, with a long anticipated service life, utilise a metal back up system to the packer elements. Baker use a series of back up rings whilst Otis packers incorporate a top and bottom back up shoe.

(b) Slip System

The system of slips comprise a set of mechanical latch keys which are located either above or below, or both above and below the sealing element. The purpose of the slips is to support the packer during the setting operation and subsequently, in some cases, to prevent the unplanned reversal of the element extrusion process. The slips act by being forced into contact with the inside wall of the casing and the serrations on the surface of the dog segments, dig into the casing wall. The packer may be required to support some of the slackened off tubing weight onto the inside wall of the casing.

(c) Setting and Release Mechanism

The packer can either be set independent to the completion string or as an integral part of the string. Since it will be desired to set the packer at a specified depth, it is necessary to be able to control the actuation of the setting mechanism only when required.

Similarly, the release of the packer has to be actuated as required.

(d) Hold Down Buttons

During production operations variation in bottomhole pressure beneath the packer can lead to significant changes in the differential pressure exerted across the packer i.e. the differential between the pressure beneath the packer and pressure in the annulus above the packer. Some designs of packer incorporate a feature known as hydraulic hold down buttons whereby the pressure in the packer bore is used to force a set of additional slips outwards onto the inside wall of the casing, thus preventing any vertical upwards movement of the packer i.e. particularly where high bottomhole pressures may exist such as in injection wells.

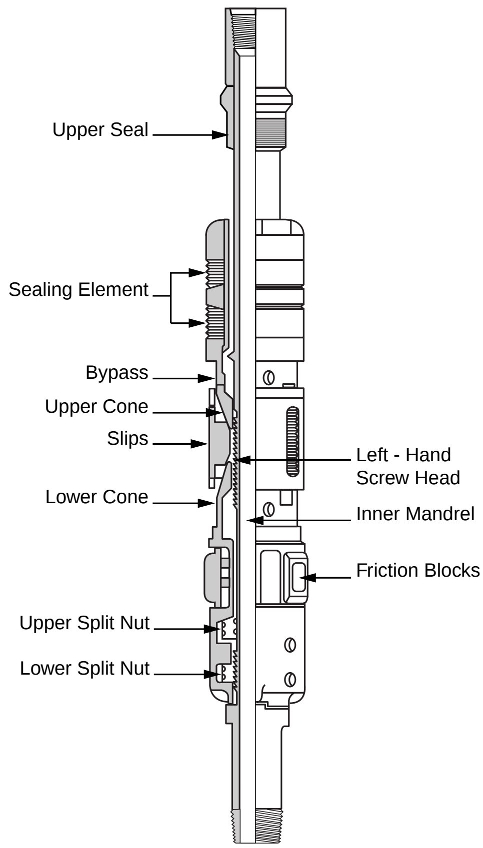


Figure 5
Components of a Typical Packer

4.3 Classification of Packers

The primary method of classifying packers is with regard to their permanency in the hole,i.e. whether the packer is retrievable or permanent. The ***retrievable packer***, as the name suggests, can be unset and pulled from inside the casing normally by manipulation which allows the reversal of the setting process to take place. A ***permanent packer*** figure 6 is designed to remain in the hole and although it can be pulled from the hole, the retrieval process is not simply the reverse of the setting procedure.

The second characteristic of a production packer is the stress state of the completion string, i.e. whether it is set in tension, compression or in a neutral state. This stress state could apply at the time of setting but subsequent pressure and temperature effects during production could cause a significant change in the stress state.

A third characteristic of packers is the nature of the setting mechanism which is used to compress the sealing element system. A number of options are available, namely:

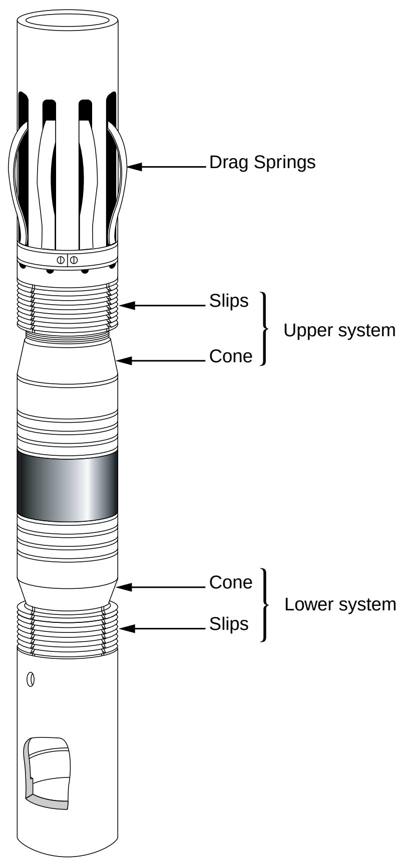


Figure 6

Permanent Packer

4.4 Running and Setting Procedures

The variety of methods available for providing the setting mechanism for the seal elements of a packer, leads to a significant number of options for installing and completing a well.

Consider firstly therefore the setting methods for packers.

I. Setting Methods for Packers

Each of the possible methods for setting a packer are outlined below:

(a) Weight-Set or Compression Set Packers figure 7

This type of packer can either be set independently or can be run in as an integral part of a tubing string and set when the string is landed off.

Normally weight set packers utilise a slip and cone assembly which can be actuated to supply the compression of the seal element, once the drag springs or friction blocks can engage the inside wall of the casing. The means to release the slips is usually obtained using a J slot device which upon activation allows string weight to be slackened off and thus compress the sealing element. Release of the element can be obtained by picking up string weight.

This type of packer setting mechanism will only be suitable if weight can be applied at the packer which may not be the case in highly inclined wells. In addition the packer will unseat if a high pressure differential exists from below the packer.

(b) Tension Set Packers

This type of packer is effectively a weight set packer run upside down, i.e. the slip and cone system are located above the sealing element. They are particularly useful for applications where a high bottomhole pressure and thus a differential pressure from below the packer exists. This situation occurs in water injection wells, where the injection pressure will assist in maintaining the packer set. Care should be taken to ensure that any temperature increase in the string and consequent string expansion will not provide a force capable of unseating the packer.

(c) Roto-Mechanical Set Packers

In this type of packer, the packer setting mechanism is actuated by tubing rotation. The rotation of the string either (a) forces the cones to slide behind the slip and thus compress the seal, or (b) releases the inner mandrel such that tubing weight can then act upon the cones to compress the sealing element.

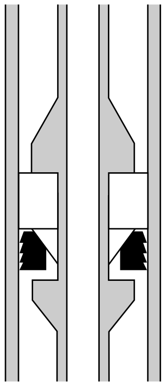


Figure 7
Mechanically Set
Compression Packer

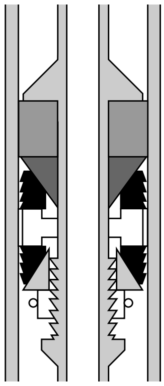


Figure 8
Mechanically Set Tension
and Compression Packer

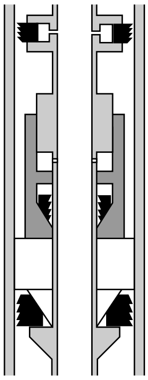


Figure 9
Hydraulically Set
Compression Packer

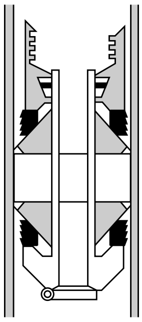


Figure 10
Permanent Packer

(d) Hydraulic-Set Packers figure 9

In this type of packer, hydraulic pressure generated within the string is used to either:

(1) drive a piston to effect movement of the slip and cone system thus comprising the seal element, or alternatively

(2) actuate a set of upper slips in the packer which will then fix the packer position and allow tension to be pulled on the packer and compress the seal system.

In the former arrangement, once the hydraulically driven piston has actuated movement of the cone, return movement of the cone must be prevented by a mechanical lock device.

To allow the hydraulic pressure to be generated in the tubing prior to the setting of the packer, 3 main techniques are available for plugging the tubing:

(1) The installation of a blanking plug such as a Baker BFC plug inside an appropriate nipple such as the Baker BFC seating nipple.

(2) The use of an expendable seat into which a ball can be dropped down the tubing string. Upon applying overpressure after setting the packer, the ball and seat shears out and drops into the well sump. An alternative design features an expandable collet which will move down and expand into a recess once overpressure shears the pins, thus allowing the ball to pass through.

(3) The use of a differential displacing sub, which allows the tubing fluid to be displaced through ports on the sub prior to setting the packer. The ball when dropped, will seat on an expandable collet which will allow pressure to be generated. Once over pressure is applied the collet moves downwards and in so doing, closes the circulation valve and allows the ball to drop through.

(e) Electric Wireline Setting Packers

In this system, a special adaptor kit is connected to the packer, with or without the tailpipe, and the system is run into the well on the wireline with a depth correlation instrument such as the casing collar locator C.C.L. At the setting depth, an electrical signal transmitted down the cable ignites a slow burning explosive charge located in the setting tool which gradually builds up gas pressure and actuates a movement of a piston to compress the seal system.

This type of system leads to more accurate setting depth definition for a packer plus a fairly fast setting/installation procedure. The disadvantages are the difficulty of running wireline in high angle wells and the fact that the packer must be set separately from the subsequent installation of the tubing.

II. Running Options for Packers

Packers can be run in any of the following ways:

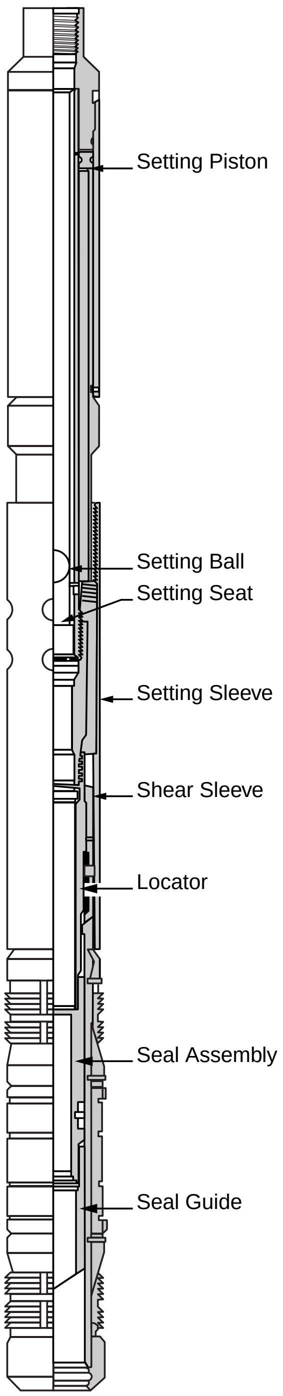


Figure 11
Hydraulic Setting Tool with Setting-Shear Sleeve and Type WB Packer

(a) As an integral part of the completion string using a hydraulic compression/tension weight set or roto-mechanical setting procedures. This usually provides the most direct method of installing a completion but requires the applicability of tubing manipulation or hydraulic setting. Figures 11 and 12.

(b) The packer being preset in the wellbore and the entire tubing string being subsequently run in through the bore of the packer or to latch into the top of the packer. This option allows the use of the wireline setting option.

(c) The packer with the lower tubing section or tailpipe suspended below it is run into the well and set on a workstring or with electric wireline. Figure 13. The rest of the tubing string is then run down to seal into the packer bore or to seal and latch into the top of the packer.

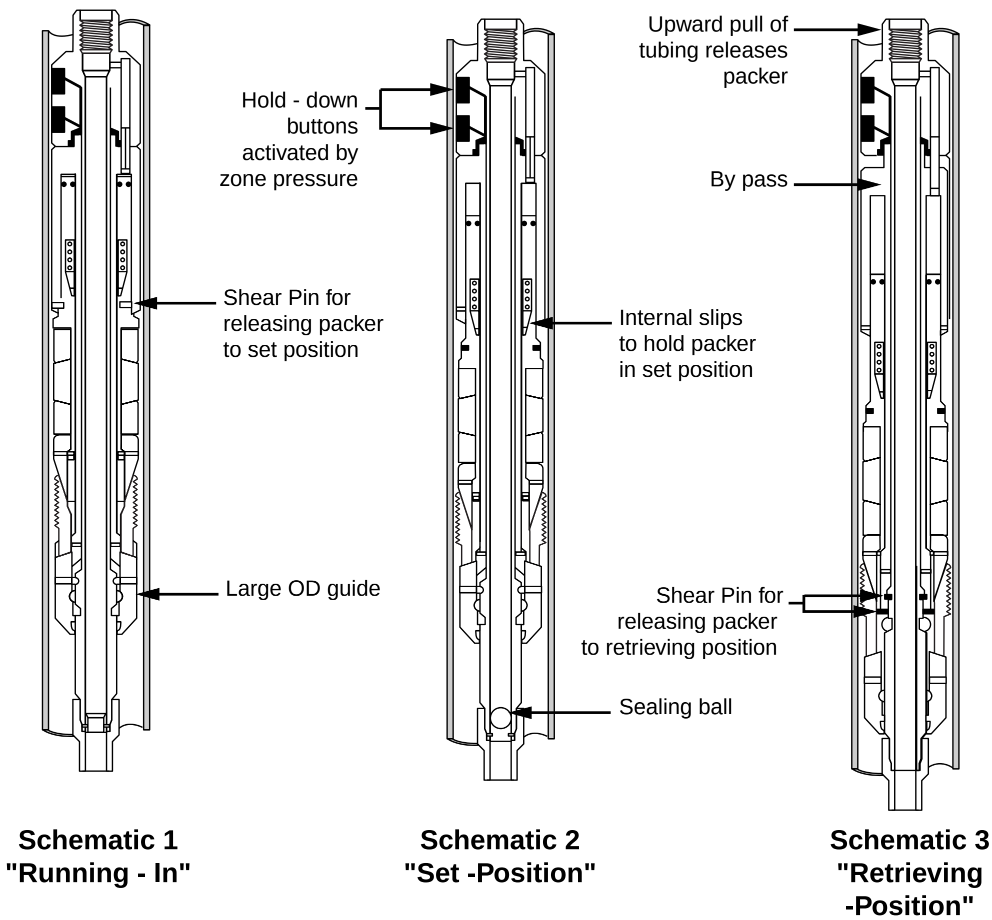


Figure 12 Hydraulically set retrievable packer using ball and seat assembly and incorporating hydraulic hold down buttons.

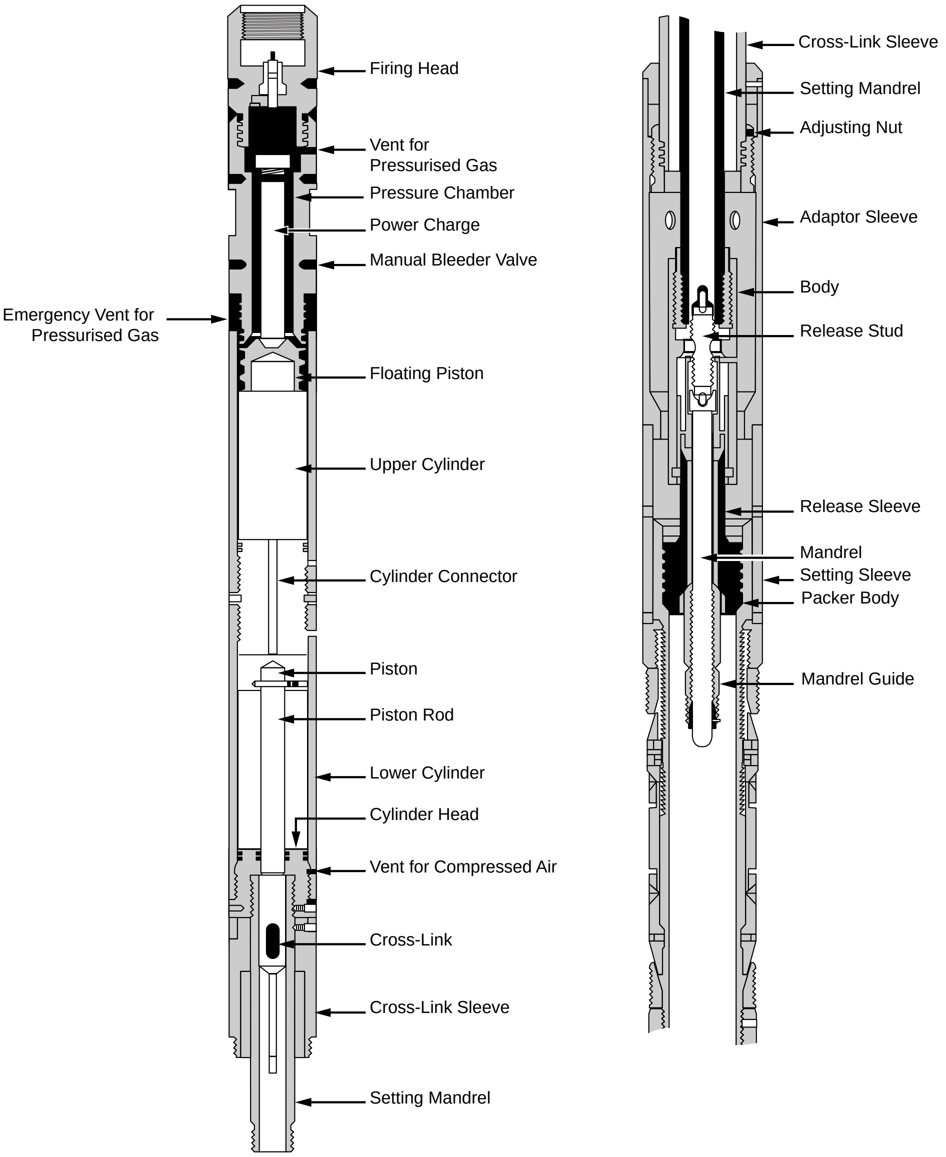


Figure 13
(a) Wireline Pressure Settiing Assembly
(b) Wireline Adaptor Kit installed in Retainer Production Packer

4.5 Permanent Packers

Permanent packers are thus described because their design permits the sealing elements, once extruded onto the inside of the casing wall, to be mechanically locked in place. This is accomplished by having two opposing sets of mechanical slips, one located below and the other above the sealing element. Thus the packer is designed to create an effective seal independent of any subsequent changes in wellbore conditions following the completion operation. Permanent packers can be set by any of the following methods:

(1) Electric wireline set.
(2) Run on tubing/drillpipe and set by mechanical manipulation - rotation.
(3) Run on tubing and set by internal hydraulic pressure.

Permanent packers do find wide application in a variety of well completions and their application is highly suited to deep, high pressure wells and in wells where there is likely to be significant forces acting, as a result of well conditions, to unseat the packer. Conversely, permanent packers provide effective annulus isolation by being designed for permanent installation and are therefore difficult to retrieve from the well.

A wide range of permanent packers are available for use with wireline, mechanical and hydraulic setting operations.

One of the earlier designs of permanent production packer the Baker Model D which is frequently set using electrical conductor wireline but can also be set on tubing or drill pipe. It features two opposing sets of full circular slips and the element is prevented from over extrusion by metal back up rings. The bore of the packer is smooth throughout its length to provide a long sealing area. The Baker Model DA is of similar design to the Model-D but offers a larger seal bore at the top of the packer.

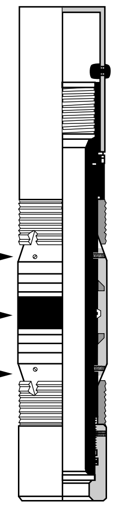


Figure 14
Baker model D packer

The Baker Model F packer offers a larger bore but is still based upon the Model D packer and offers the same mechanical design features. Similarly, the Model FA packer offers the larger bore of the Model-F with an increased seal bore capability at the top of the packer. Again the Models F and FA packers are designed for mechanical setting or setting using an electric wireline system. The hydraulic setting option is offered by the Baker Model SB-3, which is of similar mechanical construction to the Baker Model-D packers. The packer is run on a shear release assembly which after setting will act as the retrievable setting system. The packer will set with a tubing pressure of 2500 psi which is generated against a ball dropped down the string onto a shear out seat assembly at the bottom of the packer. The SB-3 is designed to withstand differential pressures up to 10,000 psi. Hydraulically set versions of the DA and FA Baker packers are also available known as the Model SAB packers but these are run on a K-22 anchor seal assembly.

The Baker Model-N packer is a mechanically set packer which is run and set with a Roto-Set seal assembly. The packer is run to the setting depth, and, using right hand rotation, release of the upper slips is achieved. Pulling upwards with 20000-30000 lbs pull will achieve the setting of the element and the lower slips. Release and retrieval of the roto set seal assembly is achieved using right hand rotation and upwards pull.

An alternative range of permanent packers is available from Halliburton and referred to as the Perma-Drill range figure 15. The Perma drill packers are available for wireline setting (type WB), for tubing setting (type TB) and for hydraulic setting (type (HB). The tubing set version uses a rotational setting tool. For the hydraulic setting system, a ball is dropped onto a seat or a plug placed in a nipple beneath the packer allowing pressure to be built up to the 2000 psi required to set the packer. The Perma Drill utilises 3 seal elements with metal back up shoes above and below the element. In addition, a J-latch receiving head is available for connecting seal units.

Several other vendors offer a competitive range of permanent packers.

4.6 Retrievable Packers

Retrievable packers are normally set using either a mechanical setting mechanism or a hydraulic system whereby the packer is usually run as a part of the completion string. A limited number of packers are available for wireline. An example of the later is the RETRIEVA - range of packers produced by Baker. The range features Models D, A and B and are largely based upon the principle of using an opposing pair of slips to prevent upwards or downwards movement of the packer. The packer is usually retrieved by a straight pull on the tubing.

The Baker Model R-3 is a compression set packer which features a set of lower slips beneath the 3 element seal system and optionally an upper set of hydraulic hold down buttons (double grip or single grip systems). It has application for a range of production wells where low to moderate bottomhole pressures can be anticipated. The packer is set by pulling up at the setting depth, applying right hand rotation and slackening off weight. Retrieval requires only an upwards pull to unseat the packer.

The “Lok-Set” range of packers (Baker) use a system of slips to oppose upwards and downwards movement and these are located beneath the 3 element sealing system. The packer is claimed to have application for withstanding differential pressures in either direction and does not use hydraulic holddown. The packer is run on tubing to the setting depth and set by rotation. In sequence, the packer requires 6000 lbs setdown weight with rotation to release and set the upper slips, followed by 10-12000 lbs to release lower slips and finally 6-10000 lbs to lock the seal element. To release and retrieve the packer requires upstrain and right hand rotation.

A simple compression set packer is provided by the Model G (Baker). To set the packer, it is run down to 1 ft below the setting depth, picked up to the setting point and after 1/4 turn right hand rotation, the weight is slackened off. To retrieve the packer requires only an upwards pull.

Hydraulic set retrievable packers offer a very useful facility since they allow flexibility and simplicity in completion operations particularly in deviated wells where mechanical reciprocation may be ineffective and undesirable. The Baker FH hydrostatic packer is run as an integral part of the tubing string and is set by pressure generated within the tubing against a ball and seat sub or a plug located in a nipple. Normally 1000 psi pressure above the annulus pressure will shear the screws and actuate the hydraulic setting mechanism although this can be increased to 2000 psi if required. The ball and seat sub will be set to shear at 3500 psi in the event of the higher setting pressure being used. The packer is normally unseated by applying an upwards pull in excess of 30000 lbs.

Like Baker, Halliburton also offer a range of retrievable packers. The Otis Perma-trieve is designed to offer a similar capability to a permanent packer with the provision of a slip system both above and below the 3 element seal system. The Perma-trieve can be run and set on electric wireline, hydraulic or on tubing with rotation. The retrieval of the packer can be accomplished without milling using either tubing or non electric wireline. The opposing slip principle gives the packer the ability to withstand high differential pressures from above or below.

Halliburton also offer a hook-wall packer which is retrievable with or without hydraulic hold down button, types MH-2 and MO-2 respectively. Both packers are designed to be run and set on tubing. The packer is run to the setting depth, picked up, rotated 1/3 turn to the right and setting down 8000 lbs weight. Retrieval requires a straight upwards pull to unseat the packer. The type MH-2, with the hold down buttons, will be suitable where differential pressures exist from above or below the packer, i.e. if higher pressure exists in the annulus then it will support the weight set mechanism. However if higher pressure exists below, it will actuate the hold down button.

Hydraulic set retrievable packers are also available as single string (type RH), dual string (type RDH) and triple string (type RTH) from Halliburton. These packers utilise a set of slips below the 3 ring sealing element with hydraulic hold down buttons above it. These packers are set with a differential pressure in the tubing which can be preset to between 800-3500 psi and are released by an upward pull.

Several other vendors offer a competitive range of retrievable packers.

4.7 Packer Selection

All the major completion equipment suppliers offer packers for comparable applications and if the product is established it will no doubt have been field proven. The choice of packer will primarily be dependent upon the application and operating conditions envisaged. Aspects to be considered include:

(1) Casing size, tubing size.

(2) Depth of well and anticipated bottom hole pressure both during completion and in production with maximum drawdown.

(3) Annular fluid type and magnitude of pressure differential.

(4) The extent of thermal stress on the tubing and the potential forces which could thus be generated on the packer.

(5) Whether tubing retrieval without the packer would be a useful facility.

(6) The bore offered by the packer and the restriction thus created for running wireline be low the packer or the increased flowing pressure loss which could occur.

(7) Completion string equipment compatibility.

(8) The deviation angle for the hole will influence any setting mechanism utilising tubing manipulation or electric wireline.

(9) The design, length and hence the weight of the tailpipe might negate the use of electric wireline to set the packer because of weight limitations.

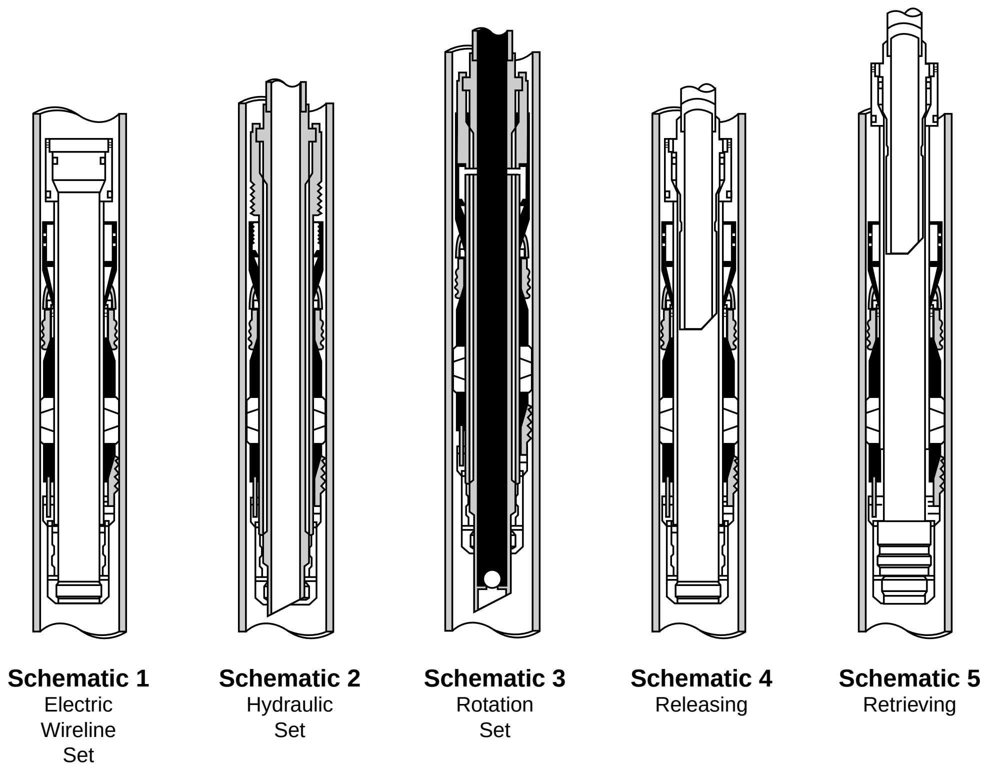


Figure 15
Different scenarios using the permatrieve packer system.

4.8 Packer/Tubing Seal or Connection Equipment

In all cases where the packer is not run as an integral part of the completion string assembled at surface, it is subsequently necessary to seal and optionally latch the completion string into the bore of the packer. The integrity of the seal system is fundamental to the effectiveness of the packer to isolate the annular space. The simplest type of seal system is one where the bore of the packer alone will provide the only internal seal surface and into which will be inserted on the base of the tubing, a tube which has a series of seal rings located around its outside diameter.

4.8.1 Seal requirements

The seals arranged on the outside of the tubing seal have to be specified with respect to:

(1) Geometrical Seal Design

Some designs utilise a seal ring whilst others utilise a Chevron Seal System. The

Chevron type packing consists of a series of directionally actuated seal rings mounted in opposing directions such that differential pressure acting across the seal area will cause the Chevron seal ring to deflect outwards to fill the gap between the seal bore and the seal tube.

(2) Chemical Composition of Seals

The composition of the seals must be specified to ensure that it is resistant to any chemicals in the wellbore, e.g. H_2S, CO_2 or other corrosive materials. A standard seal material is nitrile rubber but a range of materials are available for more corrosive service such as viton. Figure 16. The seals are usually spaced out along the length of the seal tube. A standard seal stack consists of a series of seal rings of the same material. A premium seal stack consists of a series of different types of seal rings e.g. it may consist of elastomeric rings separated by metal and/or teflon back up rings. Figure 17.

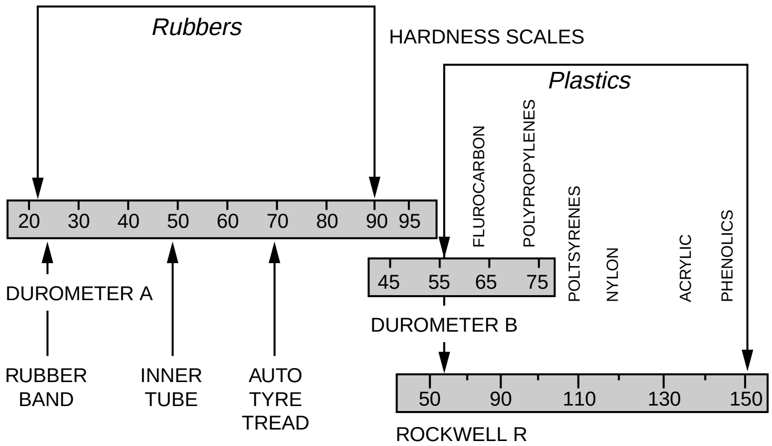
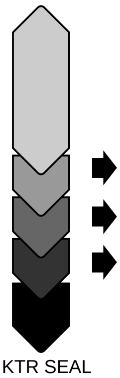


Figure 16
Hardness of elastomers and plastics



KTR	RTR	VTR
KALREZ	RYTON	VITON
TEFLON	TEFLON	TEFLON
RYTON	RYTON	RYTON

Figure 17
Premium seal stack elastomer combinations

(3) Length of Seal System

Once the seal is located within the packer bore, any expansion or contraction of the tubing will lead to movement of the seal system within the seal bore. To maintain an effective seal under all conditions, adequate length of seals must be provided. In addition, under certain circumstances it may be preferable to increase the seal bore length such that the available length of sealing is increased and the possibility of leakage reduced.

To design a sealing assembly, the maximum contraction and expansion must be defined so that the envisaged tubing travel can be compensated for. This will result in the specification not only of the type of seal rings but also:

(1) the length and arrangement of the seal bore
(2) the type of seal assembly which will be utilised to seal the tubing to the packer system.

4.8.2 Specification of the seal bore

The diameter and length of seal bore is highly dependent upon the type of packer selected as well as the casing size in which the packer is designed to be set. It is preferable to maximise the seal bore to reduce any potential restriction to flow but this also leads to an increased circumferential seal length.
Frequently, however, to increase the length of seal area and hence minimise the possibility of seal failure, a seal bore extension is coupled direct to the bore of the packer. This is accomplished by fitting a B-guide (Baker or similar) directly to the bottom of the packer which offers a box thread for the coupling up of the seal bore extension. If a retrievable packer is used or permanent packer which will not be retrieved using the milling tool/catch system, the seal bore extension will be coupled directly to the base of the packer. However, if the permanent packer is to be retrieved using the packer milling tool, then a millout extension is located directly below the packer and the seal bore extension beneath that.

4.8.3 Specification of Seal Assembly

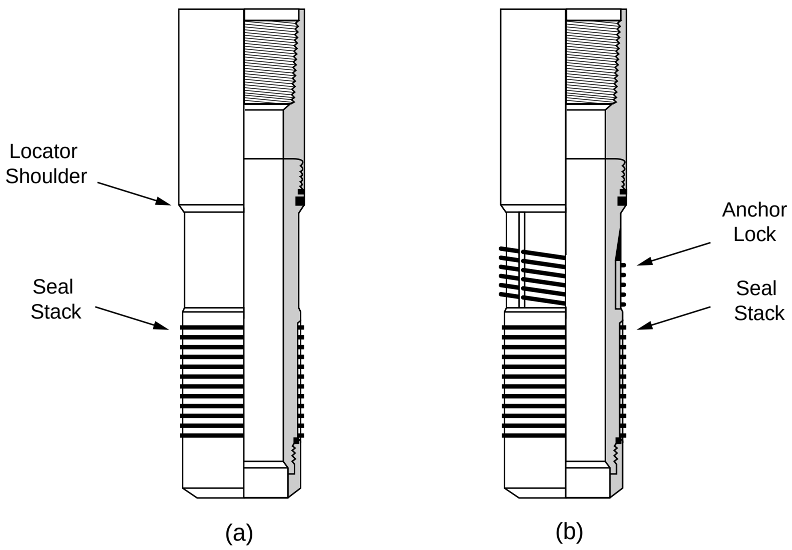


Figure 18
(a) Locator sub - tubing seal assembly and (b) anchor sub-tubing seal assembly

The simplest tubing seal assemblies can be supplied with either:

(1) a seal system only in which case they are referred to as locator tubing seal assembly, figure 18(a).

(2) a seal system with a mechanical latch above it which will engage in the upper bore of the packer, an anchor tubing seal assembly figure 18(b).

Both offer a variable length for the seal system and its configuration to suit a specific seal bore layout by adding additional seal element sections which are coupled together. Figure 19.

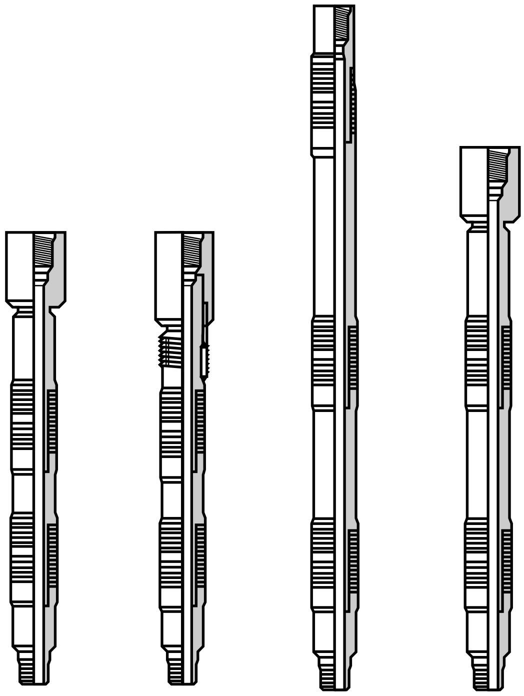


Figure 19
Spacer and locator, anchor seal system

The design of the seals to resist corrosion is primarily accomplished by specifying the seal material, however, solids deposition on the seals and sealbore, can damage the seal integrity and thus a barrier must be fitted to stop solids deposition in the seal system.

An alternative type of seal system is one which attaches to the top of the packer and consists of a seal receptacle which offers an internal seal bore and a seal assembly. One such system offered by Baker is known as an extra long tubing seal receptacle ELTSR and is designed for use where significant tubing movement is expected. The ELTSR consists of two concentric sleeves; the inner pin points upwards and is latched into the top of the packer using an anchor seal assembly and an outer receptacle, which is built up from a series of segments containing internal seal rings. The facility exists at the top of the slick joint to instal a model-F seating nipple to accept a wireline plug for isolation. In the running position, the slick joint and seal receptacle are in the closed position and connected by a J slot. The ELTSR is run down, stabbed into the packer bore and after unlatching the J-slot the seal receptacle is pulled back to space out the completion tubing. The spacing out is designed such that at maximum expansion the seal receptacle will not bottom out on the packer and for maximum contraction it will not be pulled off the top of the slick joint. The J slot can be specified to provide either right hand or left hand rotational release. The system is retrieved by initially pulling back the seal receptacle on the base of the tubing string and then running a slick joint retrieval tool with a J slot which runs over the slick joint, engages with a J slot and after pulling upwards with rotation, the anchor seal assembly backs out.

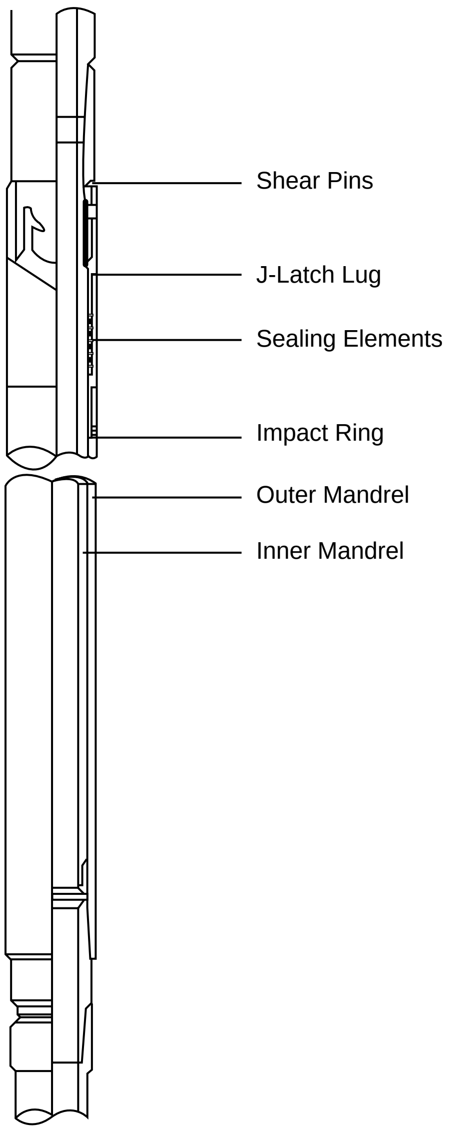


Figure 20
Tubing Travel Joint

An alternative system is the Baker Expanda joint shear release system which is similar to the ELTSR except that :

(1) the seal rings are located on the pin or slick joint assembly and hence the outer seal receptacle offers the internal seal bore

(2) the slick joint and seal receptacle can both be retrieved with the tubing for seal inspection and replacement.

An alternative system supplied by Halliburton known as the Travel Joint figure 21 effectively uses the same principle of two concentric sleeves as exists on the ELSTR but the seal receptacle is attached to the packer and points upwards, whilst the seal assembly is located on the downwards slick joint. The joints are normally run in the fully closed position and released to accommodate travel when they are in position by setting down tubing weight and disengaging the sleeves with wireline or with a shear pin release system. To retrieve the travel joint, tubing weight is slackened off, a J-slot is engaged and the system pulled from the wellbore. Travel joints are available in multiple units of 10 ft.

Two systems giving very limited movement of 1-2 ft are available and these are the telescoping keyed joint and the telescoping swivel joint.

4.9 Packer tail-pipe system

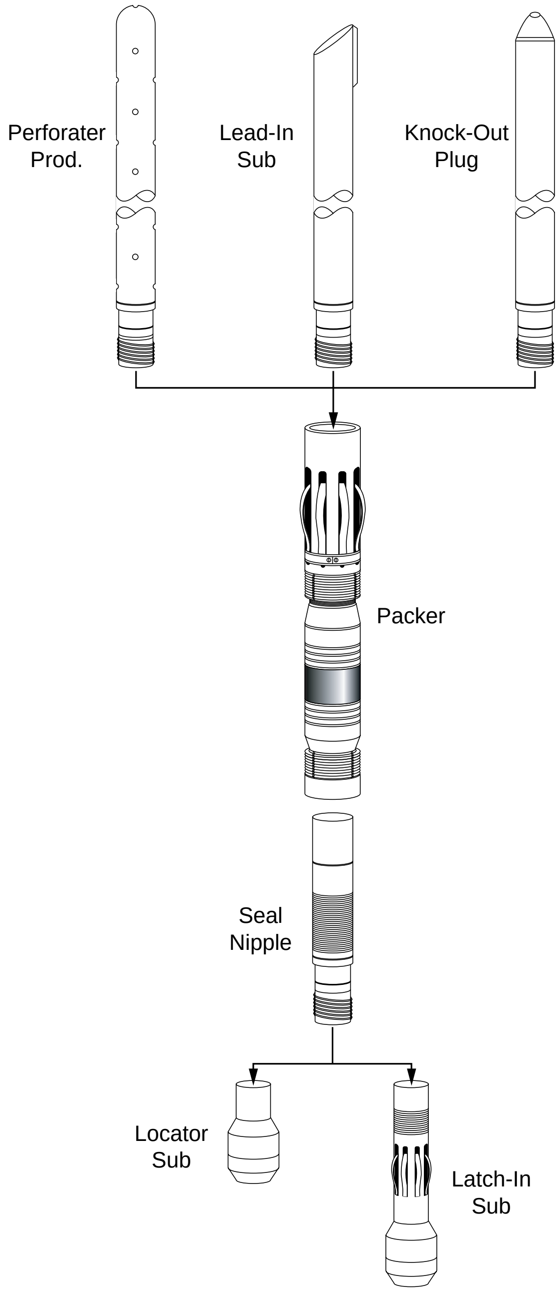


Figure 21
Seal, packer and tailpipe assembly option

The tailpipe suspended beneath the packer performs a number of functions:

(1) Provides an entry flow path for produced fluids into the tubing.

(2) Provides a nipple capability for plugging the tubes beneath the packer.

(3) Provides a nipple capability for landing off pressure and temperature gauge systems for monitoring flow.
(4) Provides a millout extension as a latch area for packer retrieval operations.

(5) Provides additional seal bore length.

(6) Allows for easy re-entry of wireline tools back into the tubing.

Working from the bottom up, a wireline entry guide or mule shoe is normally located at the base of the tailpipe. This has a funnel guide so that wireline tools being pulled back into the tubing are properly aligned. Above the WEG is normally located a seating nipple which will accept the landing off and mechanical latching of a gauge system run on wireline. Above the lower nipple, a perforated flow tube provides maximum flow area for fluid entry thus: (i) preventing turbulence and potential tool damage at the WEG, and (ii) entry for fluid if the lower nipple is plugged by a gauge. Above the perforated flow tube is located a nipple for the pressure isolation of the production zone in the event of a workover or the need to pull tubing. The seal bore extension is located above that and then the millout extension immediately beneath the packer.

4.10 Permanent Packer Retrieval Systems

If a permanent packer is used then the seal element cannot be released if the opposing slips above and below the packer remain in place. The requirement is to mill away the internal sleeve which holds the top slips in place and then the packer wil be free to be pulled from the well. The milling operation normally takes between 3-6 hours and the millhead is guided into the packer and maintained in place by a guide rod which passes through the packer bore. The milling tool is also fitted with a retrieval tool which incorporates a catch sleeve which will collect the remains of the packer when the milling operation is complete and the tool retrieved. Figure 22

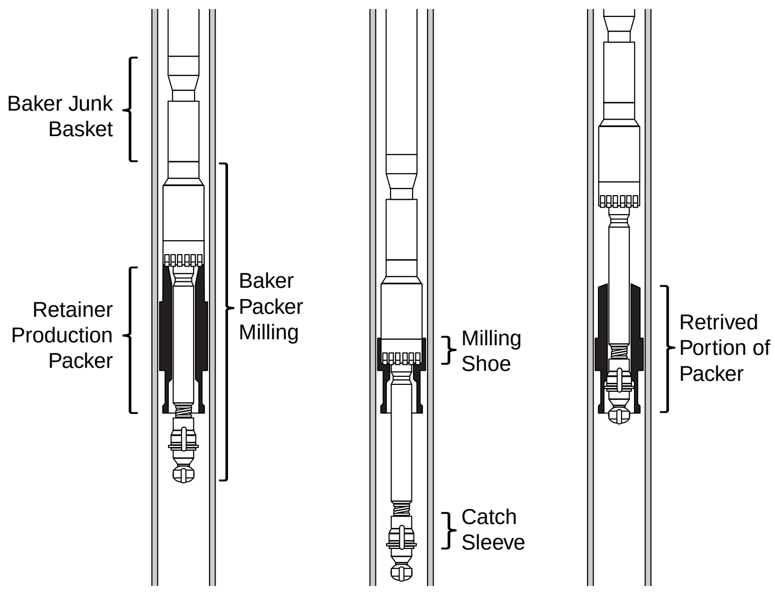


Figure 22
Packer Milling Tool illustrating one trip milling and retrieval

If the packer is run with a tailpipe, a millout extension sleeve must be run immediately below the packer in which the catch sleeve will locate.

5 WIRELINE SERVICED NIPPLE AND MANDREL SYSTEMS

A nipple is a tubing sub which has a box and pin threaded connection, and a precisely machined and configured, internal bore. This internal bore will accept a suitably sized mandrel having a matching external profile which can be run down the inside of the tubing string using wireline. The nipple normally provides two facilities:

(a) a facility to allow latching of the mandrel within the nipple profile.

(b) a sealing capability for the mandrel within the bore of the nipple.

The nipple therefore has to offer a landing/locking profile and a seal bore. To avoid mechanical damage, the seal bore is generally located beneath the locking profile.

A variety of nipple/mandrel systems are available to offer the following capabilities:

(1) Isolation or plugging of the tubing string for well shut in, workover or for hydraulically setting packers.
(2) A ported device which allows communication between the tubing and the annulus.
(3) Emergency closure of the tubing or annular flow conduit by remote or direct control.

(4) Downhole regulation or throttling of the flow.

(5) The installation of downhole pressure and temperature recording gauges.

Two basic types of landing nipple are available: the selective and the non-selective.

5.1 Selective Landing Nipple System

There are 3 methods of obtaining selectivity in a landing nipple system:

(a) selectivity based upon a variable internal profile

(b) selectivity associated with the setting tool

(c) selectivity based upon pre-spaced magnets

(a) Selective Internal Profile

In this system, it is necessary to match the internal profile of the nipple to a set of locating keys on a lock mandrel. Normally nipples are available with 5 to 7 selective positions. The nipples must then be run as part of the completion string in the sequence denoted by the selective location keys. It is important that the nipples are run sequentially and that a note of the depth of each nipple is made to assist mandrel placement during subsequent work.

(b) Setting Tool Selective Nipples

With this system, the setting tool which includes its removable locking and sealing device is designed with a system of fixed external profiles. Thus it is the setting tool which locates the nipple and positions the lock mandrel and seal in the appropriate nipple. Using this system of selectivity an unlimited number of this type of landing nipples of the same size can be installed in the string.

(c) Prespaced Magnet Selectivity

This type of nipple system usually comprises a lower section which contains the locking profile and sealing section and an upper section in which two prespaced magnet rings are located. For a mandrel to be inserted and locked into such a nipple, two magnets also prespaced, on the running tool must correspond with the location of the rings within the nipple. The mandrel is locked in position by a mechanical locking mechanism actuated by a small explosive charge detonated by the electric circuit created when the mandrel lands in the nipple. Up to six of these nipples, of the same size, can be run in the same string.

For most applications, selectivity is preferred on the basis of variable profile or setting tool actuation.

5.2 Non Selective Landing Nipples

This type of landing nipple is frequently referred to as a no-go nipple and operates such that the outside diameter of the mandrel will be slightly larger than the minimum inside diameter of the nipple and hence prevents its passage through the nipple. In a string designed with a number of nipples to be operated on this basis, it is imperative that the nipples be designed to sequentially reduce in diameter as their installation depth in the string increases. The clearance of a mandrel through the upper nipples should be based upon the size of the locking section of the mandrel and normally the sealing bore of the nipple. The no-go profile of the nipple can be designed to be at the top or bottom of the nipple.

5.3 Available Nipple/Mandrel Systems

All the major completion equipment supply companies offer a wide range of nipple systems of varying internal profile for a range of applications.

(1) Common Baker nipple systems

Two commonly used Baker nipple systems are the Model F and Model R seating nipples. Figure 23

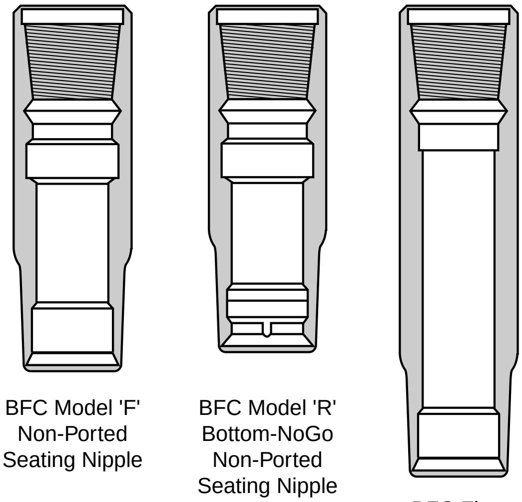


Figure 23
Baker non selective nipple systems

The Model F seating nipple features a top no-go shoulder and a locking groove above the lower seal bore section. This type of nipple can be operated on a selective or top no-go landing lock system. This type of nipple is used for a range of tubing operations including:

(a) Setting a blanking plug to isolate production

(b) Landing directly controlled sub surface safety valves, check valves, downhole chokes.

(c) To land off pressure and temperature recording gauges.

The Model R nipple is a bottom no-go seating nipple which includes a honed internal sealing bore and a locking groove/bottom no-go shoulder. It can be used for the same type of applications as the Model F nipple.

The type X and R nipples offered by Halliburton are commonly utilised in completion strings. Both the type X and R are running tool selective nipple systems. Figure 24

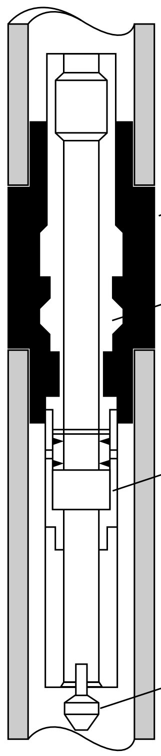


Figure 24
Halliburton types X and R equipment

The type X nipple was originally designed for completions using standard weight tubings, e.g. 31/2" or 41/2" dia. maximum in wells where the pressures would not exceed 10,000 psi. The type R nipple was developed for heavier weight or larger bore tubing strings. Both nipples were designed to offer a maximum seal bore diameter and hence minimal flow resistance. For the X and R nipples, the seal bore is located beneath the locking profile.

The mandrels used with these nipples are designed such that the locking keys are retracted allowing passage through the nipple system with minimum resistance.

For both the X and R type nipples, a no-go version is available, the type XN and RN respectively, and one of these is normally placed at the bottom of a series of type X or R selective nipples.

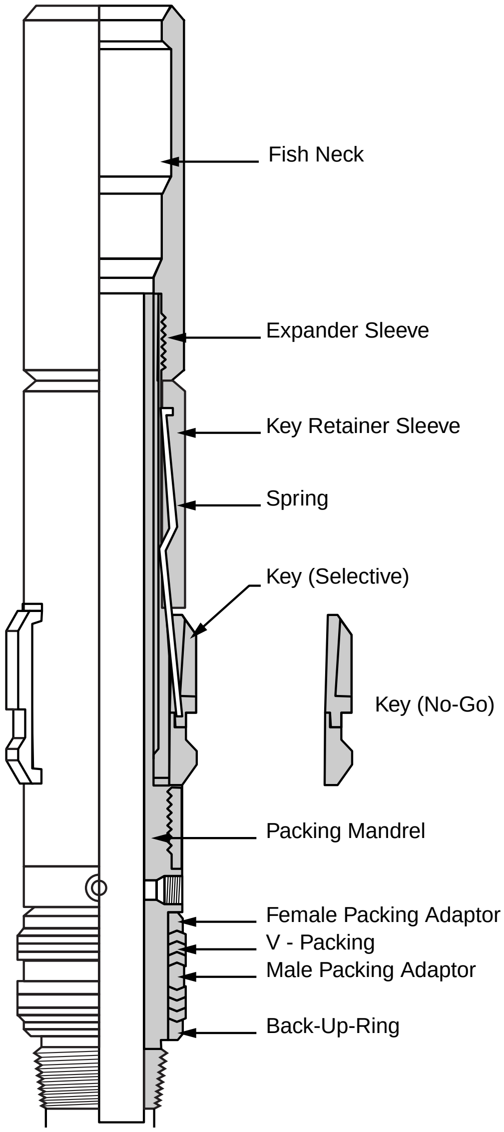


Figure 25
Representation of type X (selective) and type XN (no-go) locking mandrels (Halliburton)

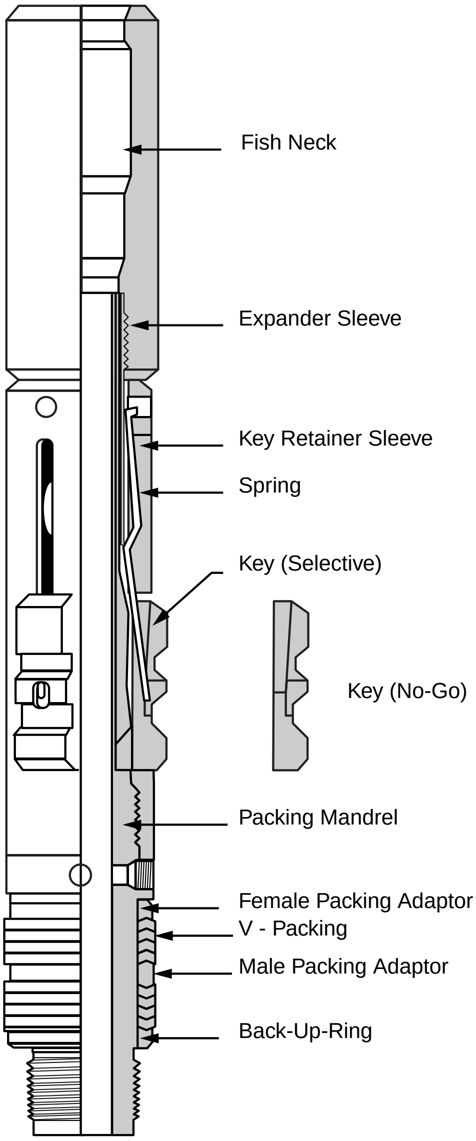


Figure 26
Representation of type R (selective) and type RN (no-go) locking mandrels (Halliburton)

The mandrels for the type X and R equipment and their respective versions with the bottom no-go, figures 25 and 26 are designed to hold high differential pressure from above or below. In the event of unseating a mandrel with a high differential pressure, pulling could be difficult or hazardous. In the event of a high differential pressure from below, the force on the mandrel could be sufficient to blow it up the tubing string. Conversely, if the pressure differential were reversed, it may require significant force to unseat the mandrel. In such cases, it is essential to equalise pressures across the mandrel prior to it being unseated. This is done by the installation of an equalising sub at the base of the mandrel. The sub has a port which is normally closed off by an internal sleeve but a prong on the mandrel pulling tool, when engaged, will open the sub.

Two other nipple systems offered by Halliburton are the type S selective and type N no-go which is non selective.

The type S nipple is a system based upon selectivity by the locating mandrel. It features 7 predetermined relative landing locations in a single tubing string into which a mandrel can be landed through the use of selective locating keys. The use of this system allows up to 7 different nipple locations to be employed. The type S nipple offers a large bore; can handle differential pressures in either direction but is only available for tubing sizes up to 41/2" O.D.

The type N no-go nipple is a non selective landing nipple which is frequently employed as the bottom nipple on a string comprising several type S nipples.

5.4 Setting Mandrels not requiring a nipple profile

In a properly designed well completion, nipple locations are identified and this provides the capability for installing downhole equipment based upon the landing and locking profile so provided. However, occasionally the need arises to be able to land off equipment in the tubing where a nipple is not available, e.g.

(1) where a nipple seat has been damaged or access to the locking profile is difficult

(2) where a mandrel cannot be retrieved from a nipple

(3) where a suitable nipple location has not been provided.

In these circumstances mandrels are available for setting within the tubing or in some specific designs within the collar of tubular threaded couplings. Obviously, since the locking system will be based upon slips engaging the tubing wall or dogs entering the tubing coupling collar, the efficiency of the mechanical locking will not be as effective as a proper mandrel/nipple system. These mandrels are only suitable for differential pressures less than 1500 psi. In addition the mandrels are not recommended if the differential pressure is from above.

The type D mandrel is designed to lock in a tubing collar (for API thread couplings only) and subsequent upwards jarring provides compression of the seal element within the tubing wall. Figure 27

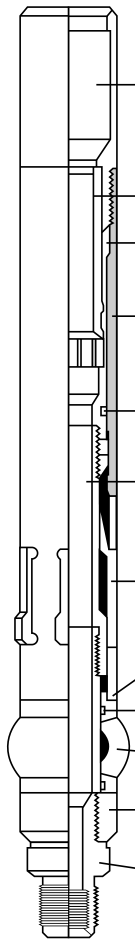


Figure 27
Type D mandrel
(Halliburton)

An attentive system in corporating opposite slips and capable of withstanding high differential pressures is known as the slide plug (petroline).

5.5 Ancillary Equipment for Nipples

Any wireline nipple installed within a tubing string with or without the relevant mandrel system, will cause some restriction to flow. The convergence and divergence effects associated with entry to and exit from the nipple system will cause severe turbulence and eddying currents. This turbulence can lead to substantial abrasive action on the tubing wall and nipple system. To protect against this abrasion, flow couplings are installed above and below the nipple to act as flow straightening devices. Figure 28

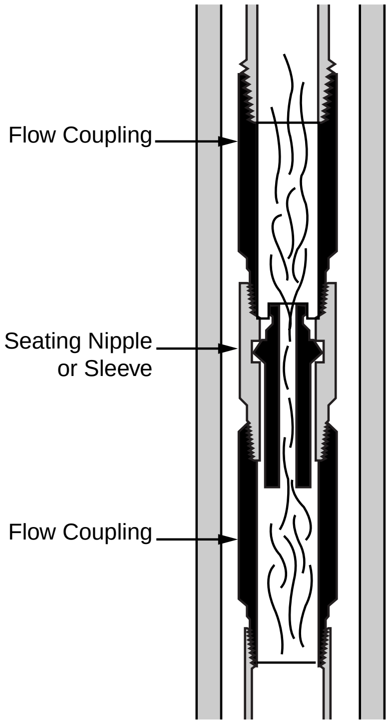


Figure 28
Correct installation of Baker flow coupling

6 SUB SURFACE SAFETY SYSTEMS

For well isolation or closure under normal operating conditions, the production wing valve and mastergate valve will be used. The advantage of these valves is that if the valve malfunctions, then it can be repaired or replaced with little difficulty. These valves are therefore defined as being the primary closure system for the well.

However, in the absence of an effective surface closure system, well security is endangered. This could occur in a variety of situations:

(1) Xmas tree removal during workover preparations to pull tubing

(2) Removal of valves or valve components for servicing

(3) Accidental damage to Xmas tree

(4) Leakage on wellhead - Xmas tree flange seals

To provide some degree of security in the event of any of the above situations occurring, it would be ideal to have a safety valve system located beneath the wellhead within the tubing system. This component is termed a Sub-Surface Safety Valve or SSSV. These valves are available based upon two different control philosophies, namely:

(1) Direct Controlled SSSV (D.C.SSSV) which are designed to close when downhole well conditions of pressure/flowrate vary from preset design

values. These valves are often refered to as "storm chokes".

(2) Remotely or Surface Controlled SSSV (S.C.SSSV) whereby closure and opening of the valve is actuated and accomplished using a surface control system which feeds hydraulic pressure directly to the downhole valve assembly.

Both valve systems are designed to provide protection in the event of a catastrophic loss of well control.

6.1 Direct Controlled Sub Surface Safety Valve

These valves are installed on the basis of a design flow condition within the tubing string. The valves can be run and installed within specific landing nipples within the production tubing.

The preset control for closure of these valve systems is:

either

(1) Pressure differential operated valves assume a specific fluid velocity through a choke or bean, which is part of the valve assembly. The valve has a spring to apply the closure force. The valve will remain open provided the differential pressure does not exceed the present design value. If an increase in flowrate occurs sufficient to increase the differential pressure beyond the preset level, then the spring will affect valve closure.

or

(2) Ambient type or precharged dome/bellows valves utilise a precharged gas pressure in a dome to act as the valve control. If the flowing pressure drops below the precharged pressure,then the valve will automatically close.

Direct controlled valves are available from all the major equipment supply companies. The available valve systems vary in the valve configuration applied, e.g. the following alternatives are frequently used:

(a) poppet type valve and seat

(b) ball valve and seat

(c) flapper valve and seat

(1) Differential pressure operated safety valves

The type F safety valve (Halliburton) is a differential pressure operated valve which operates using a spring loaded flow bean or choke. During normal operation, the valve is held open by the upstream pressure compressing the spring. When the preset flowrate is exceeded, the flowing pressure decline will give rise to spring expansion downwards and valve closure. The valve can be run and retrieved on wireline and can be landed in any appropriate nipple using the applicable mandrel system.

The type J valve utilises a ball valve and cage system. Compared to the type F, the valve has a larger bore and is designed for higher flowrate wells being available in sizes up to 3.72" O.D./2.0" I.D. The spring in its extended state holds the valve offseat and hence in the open condition. An increase in flowrate gives rise to a higher differential pressure across the bean and hence spring compression occurs and as the bean retracts upwards, the ball is designed to rotate and seal via the control arm.

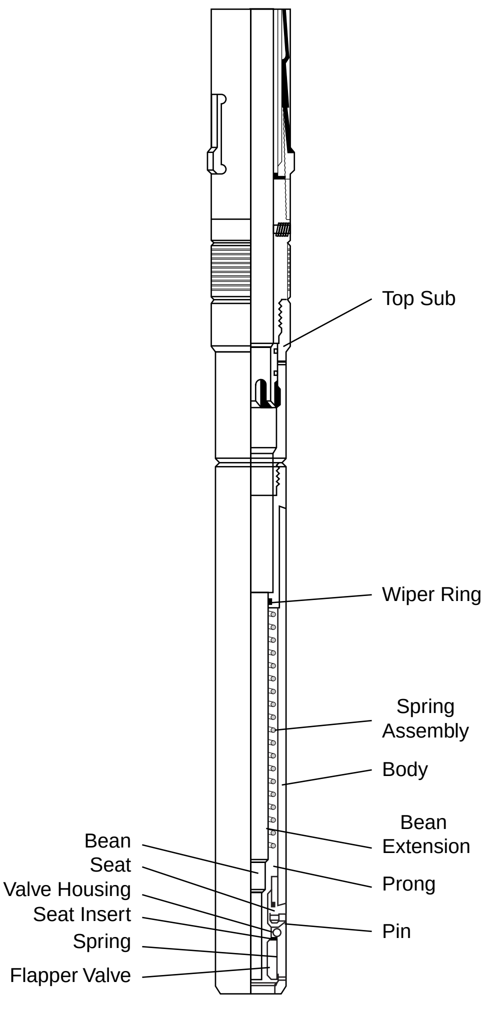


Figure 29
Type M pressure differential tubing safety valve (storm choke) Halliburton

The type M valve (Halliburton) is similar in operation to the type J except that a spring loaded flapper is used as the valve. Figure 29. An increase in flowrate through the bean produces compression of the spring and as the flowtube retracts upwards, the flapper springs shut across the flow area. The flapper and ball valve types offer similar flow dimensions.

(2) Ambient or precharged type safety valves

The type H valve (Otis) is designed with a piston loaded with a spring. Below the piston, the chamber is filled with fluid precharged to a set pressure whilst above the piston tubing pressure is applied through a port in the flow tube. If the tubing pressure in the flow tube falls below the precharged dome pressure, the flow tube retracts by spring expansion and the effect of pressure on the piston and the ball valve rotates to the shut position. The type of closure is a more positive means of obtaining closure since it does not depend upon pressure differential created by flow through a choke as this may be unreliable. The type H is available with a bore up to 2 inches.

The type K ambient safety valve again uses a precharged dome pressure to act on a piston to effect closure. The valve responds to a reduction in well pressure which, due to the imbalance in pressure compared to the dome pressure, drives the rod upwards and the valve onto the seat to close the valve. This valve offers the maximum bore available with any directly controlled safety valve.

All the above safety valves can be run into the tubing string on wireline or coiled tubing and landed off using an appropriate mandrel nipple combination.

To reopen the valves after closure requires equalisation of pressures across the valve by

either

(1) the application of tubing pressure above the valve to equilibriate fluid pressure

or

(2) the use of a wireline prong to open the valve.

Advantages of Direct Controlled Sub Surface Safety Valves

(1) Simple construction and operating principle

(2) Easy installation and retrieval since no control line from surface is required

(3) Cheaper installation cost

Disadvantages of Direct Controlled Sub Surface Safety Valves

(1) The valve systems are not 100% reliable since they depend upon preset deliverability and pressure conditions.

(2) Especially for the choke type valves, the valve performance and closure may be affected by wax deposition or erosion of the orifice. It is imperative that with these systems the valve is pulled and regularly inspected or replaced.

(3) The valve system can only be designed to reliably operate if an extreme condition occurs in relation to changing flowrate and pressure.

(4) Declining productivity may make it impossible for the designed closure conditions to be actually realised.

(5) Testing of valve closure (if possible) is not easily accomplished.

6.2 Remotely Controlled Sub Surface Safety Valves

These valves are designed to be installed downhole in the tubing string and are held open by hydraulic pressure supplied to the valve via a control line. Figure 30. The closure mechanisms utilised in these valves are either ball or flapper type assemblies.

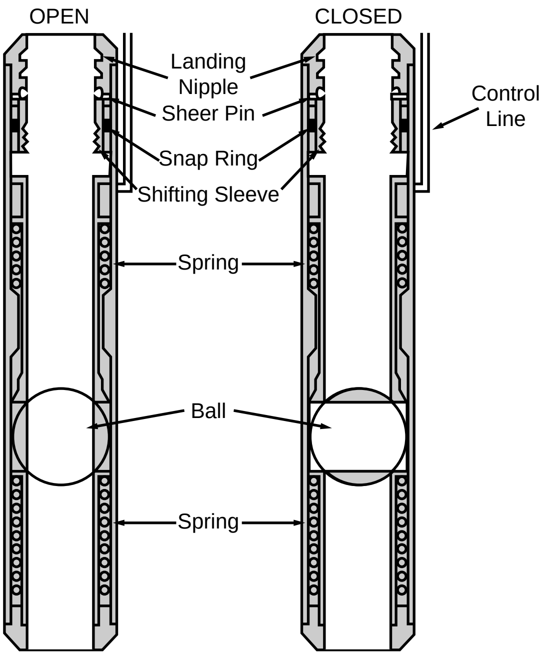


Figure 30
"Dual Application" remote controlled sub-surface tubing safety valve

The valves available are of two distinct types, namely, the ***tubing retrievable*** and the ***wireline retrievable*** valves.

The tubing retrievable valve system is a screwed tubular component which is made up as an integral part of the tubing string and run into the well. Removal of the valve can only be accomplished by pulling back the tubing string.

The wireline retrieval valve system consists of a conventional wireline nipple which will accept the appropriate mandrel which in this case is the valve assembly itself.

1. Tubing Retrievable Sub Surface Safety Valves

The tubing retrievable valve is a threaded top and bottom tubular component whereby the valve assembly is held open by hydraulic pressure fed down the control line on the outside of the tubing.

In all cases the valve assembly consists of a spring loaded flow tube and piston assembly, whereby hydraulic pressure fed into the cylinder above the piston provides compression of the spring beneath the piston. The resultant downwards movement of the flow tube serves to keep the ball valve or flapper open. If hydraulic pressure is bled off the control line, the spring supplies the return pressure to cause upwards movement of the flow tube and closure of the valve.

The type QLP and DL tubing retrievable safety valves (Halliburton) are examples of a flapper and ball type safety valves respectively. These valves offer minimal restriction to flow with their large bores. For the valves it is recommended that tubing pressure above and below the valve be equalised prior to applying hydraulic pressure down the control line.

A modified flapper system is available with the Baker FV series tubing retrievable SSSV. These valves use a flapper which is designed for “self equalisation” through the use of a small spring loaded plunger on the flapper. As the flow tube moves down when hydraulic pressure is applied, the end of the flow tube contacts and opens the plunger allowing pressure equalisation.

Most applications of a tubing retrievable SSSV also incorporate a special nipple known as a wireline extension for a tubing retrievable SSSV. This device is installed immediately above the tubing retrievable SSSV as part of the tubing string and in the event of valve failure, a wireline retrievable SSSV mandrel can be installed which locks open the tubing retrievable valve and the hydraulic pressure from the control line is redirected onto the wireline valve.

2. Wireline Retrievable Sub Surface Safety Valves

Again the completion equipment supply companies offer a range of wireline retrievable SSSV. The operating conditions are similar to the procedures employed with the tubing retrievable valves except that the valve is run on a wireline mandrel into a special tubing nipple profile (figure 31) and not a tubing sub. This type of valve is available either as a ball type system or as a flapper valve.

The type DK (Halliburton) is an example of a wireline retrievable ball type valve whereby the valve has an outer lower seal assembly and an upper latch assembly compatible with the appropriate nipple. The valve and sealing surfaces are partially protected from wellbore fluids to restrict corrosion and abrasion during flowing conditions. Further, each time the valve is opened, the design incorporates a system to wipe clean the ball and seat.

As with the tubing retrievable ball valve it is recommended that pressure be equalised above and below the valve prior to opening with the application of hydraulic pressure.

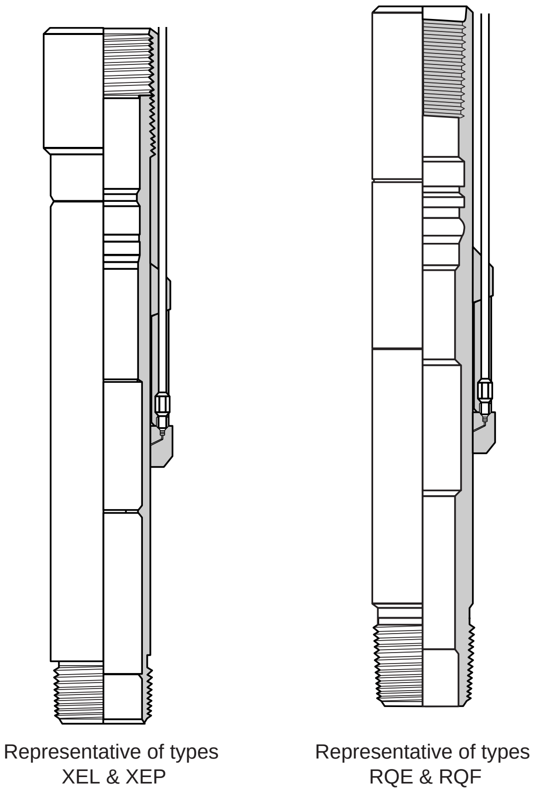


Figure 31
Wireline retrievable valve nipple systems (Halliburton)

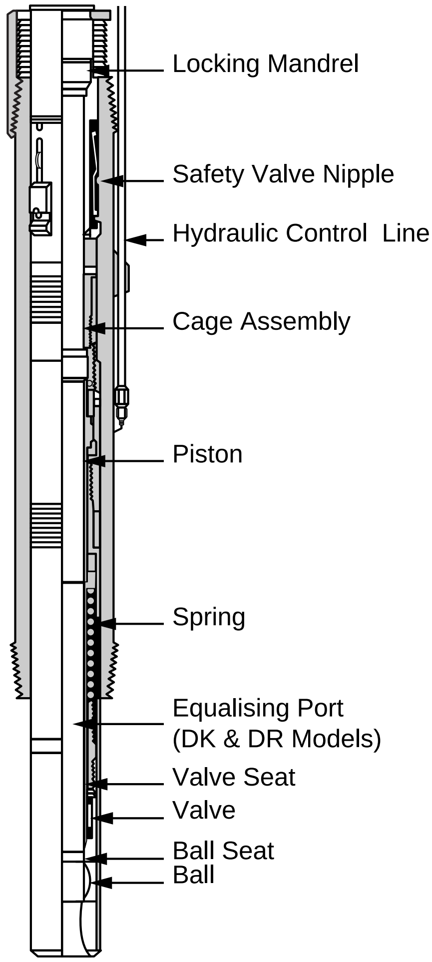


Figure 32
Type DK Halliburton tubing safety valve installed in safety-valve nipple

One additional feature with this type of valve is that if hydraulic pressure is bled off, fluid can be pumped down through the tubing for well killing operations. The comparable flapper type valve is the type QO

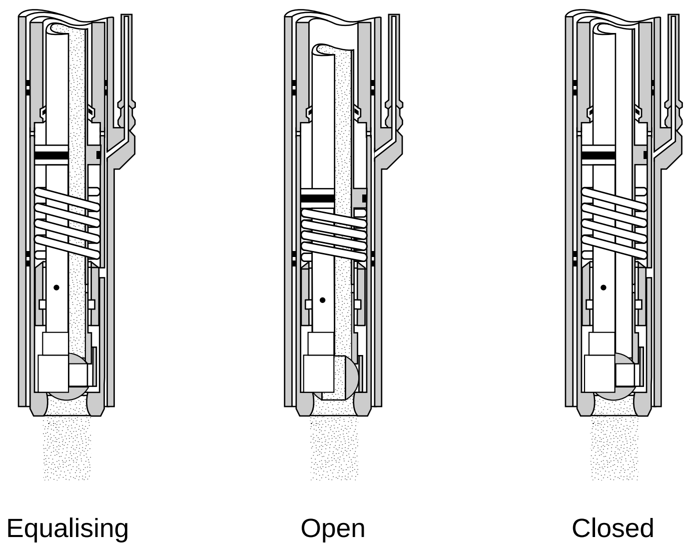


Figure 33
Operation of DK tubing safety valves Halliburton

A system of comparable wireline retrievable flapper valves is also offered by Baker. In addition an alternative system for locking open a malfunctioning tubing retrievable valve is offered by Baker, whereby a wireline installed valve is installed in place of a separation sleeve which seals across the bore of a locked open tubing retrievable valve. This system is termed an “insert wireline valve”.

3. Comparison of Wireline and Tubing Retrievable Valves

In terms of valve mechanics both valve systems are very similar, the distinguishing characteristics are as follows:

(1) The tubing retrievable valve must be reliable for it to be effective, as otherwise its retrieval is a more involved and costly operation.

(2) The tubing retrievable valve offers a much larger flow area compared to the wireline retrievable valve and hence will cause less flowing pressure drop and not reduce attainable production rate. It is also more likely to be large enough to allow wireline operations to be conducted through it. The wireline retrievable valve offers much greater flow resistance.

4. Ancillary Equipment for Surface Controlled SSSV (Figure 34)

Surface controlled SSSV require the installation of a control line into the valve or valve nipple and this control line must be run in continuously as the tubing is installed. In addition, to protect the control line from damage downhole, it should be strapped to the outside of the tubing. The control line is normally strapped to the tubing using a fluted control line protector.

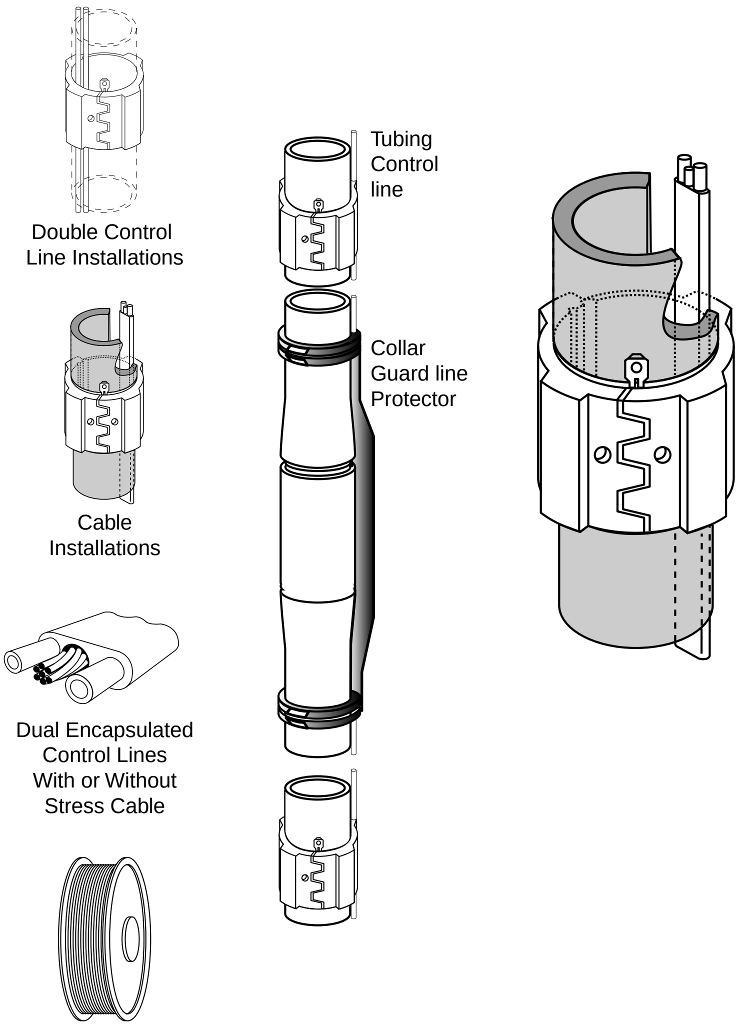


Figure 34
Control line cable installation equiptment

The control line itself is normally stainless steel or monel and is available as 1/8" or 1/4" O.D. The line is normally supplied on a reel and is unwound and attached to the tubing as the tubing is lowered into the well. Care must be taken to avoid the control line being trapped between the tubing and the slips.

The control line is connected into the downhole valve but also has to connect into the base of the tubing hanger.

Normally, when the tubing with a safety valve nipple is being run, precautions must be taken to prevent debris entering the control line. In such cases, normally a dummy sleeve or separation sleeve is positioned across the nipple and this provides a seal allowing a positive pressure to be held on the control line which not only ensures that no debris will enter the line but gives rapid detection of leakage or line damage.

When a safety valve is set very deep, there have in the past been occurrences where the pressure due to the hydrostatic head of control fluid has led to incomplete closure of the valve when surface pressure has been bled off. This effect can be counteracted by running a dual control line where one line provides the surface control pressure and the other line provides hydrostatic balance across the piston on the operating flow tube.

6.3 Injection Well Safety Valves

In injection wells, significant tubing head pressures are often employed to maximise injectivity. The use of one way check valves in water or gas injection wells can serve a very useful purpose in that as soon as injection ceases, the valve will spring shut and prevent backflow.

The valves are in effect direct controlled SSSVs. The valve systems available are the ball, flapper and stem/seat systems. The type JC (Otis) figure 35 is a ball type valve in which the inner mandrel is kept in the down position by pressure differential from above, i.e. the injection pressure. Once injection ceases, the hydrostatic head is insufficient to keep the valve open and the mandrel moves upwards, allowing the ball to rotate and close in its upward movement. The type MC (Otis) figure 36 is a flapper valve and operates in a similar fashion to the type JC. Both valves are reopened by recommencement of injection.

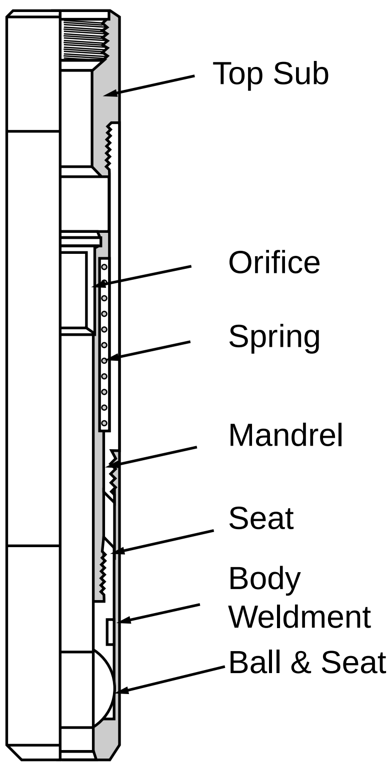


Figure 35
Type JC Halliburton injection safety valve

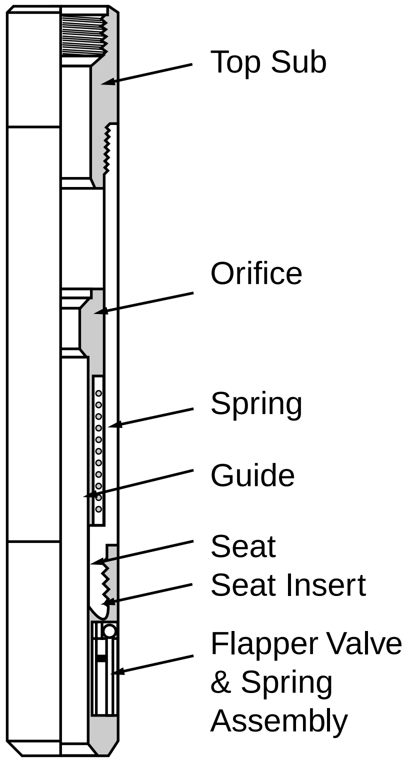


Figure 36
Type MC Halliburton injection safety valve

Another injection safety valve is the type T figure 37 which offers a very large flow area through the valve cage. Once injection pressure drops off, the restoring force of the spring moves the valve stem upwards onto its seat.

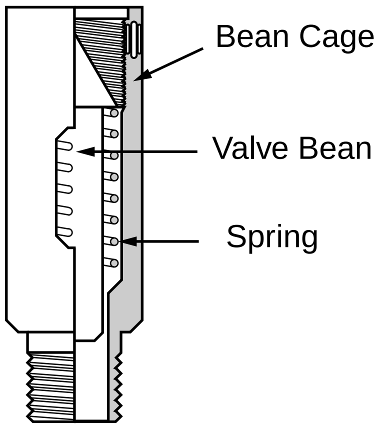


Figure 37
Type T Halliburton injection safety valve

All 3 valves are designed for installation in a nipple using an appropriate mandrel system with wireline. For simplicity the valves referred to are examples of Halliburton systems

7 TUBING - ANNULUS COMMUNICATION EQUIPMENT

One vital operation which frequently has to be performed on a well is to circulate between tubing and annulus. This is required during the following situations:

(1) To displace out the tubing contents during completion to provide a fluid cushion which will initiate production. This is normally done by displacing down the tubing and taking returns up the annulus, i.e. forward or normal circulation.

(2) To displace out the tubing contents to a heavier kill fluid to provide hydrostatic over balance of reservoir pressure prior to pulling tubing or other workover activities.

(3) To allow continuous or intermittent injection from the annulus into the tubing of fluids, e.g.,

pour point depressant
corrosion or scale inhibitor
gas for a gas lift process

There are 3 principal items of down hole equipment designed to provide selective communication capability:

(a) Sliding side door or sliding sleeve
(b) Side pocket mandrel with shear valve
(c) Ported nipple

All three systems are dependent upon wireline or coiled tubing techniques to service the equipment.

7.1 Sliding Side Door or Sliding Sleeve

Equipment of similar design is available from the major service companies but all designs feature a tubing sub with external ports through the tubing wall within which is located an inner mandrel with slots and seal rings above or below the slots figure 38. In the closed position, the inner mandrel or sleeve is located such that the ports in the outer tubing wall are isolated by seals above and below on the inner mandrel. Movement of the inner sleeve either upwards or downwards can produce alignment of the slots on the inner mandrel with the ports in the outer tubing. After completion of the circulation operation, movement of the inner sleeve in the reverse direction will return the circulation device to its closed position. To achieve the movement of the inner sleeve requires the running of a shifting tool to open and close the sleeve. The shifting tool lands in the top or bottom of the inner sleeve and by jarring, the sleeve can be moved up or down. Normally movement of the sleeve cannot be accomplished if a extremely high differential pressure exists across the sleeve. Any number of sleeves of the same size can be run in the same completion.

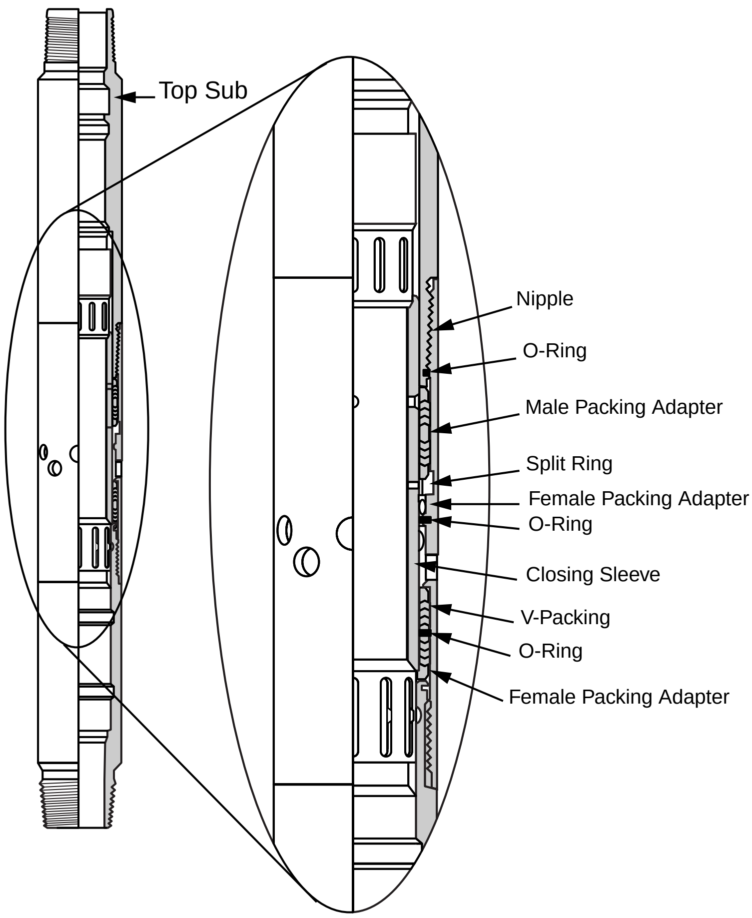


Figure 38

Sliding side door. If failure to close the sleeve on jarring occurs it might be due to solids in the seal area or the effect of well deviation and the resultant inefficient jarring. In such cases if the sleeve cannot be closed, a separation sleeve could be run which will land inside the sliding sleeve and seal in the seal bores above and below the slotted section of the inner sleeve.

Halliburton market sliding side doors which are based upon a tubing sub with a type X or R nipple profile. The inner sleeve can be specified as opening by upwards or downwards jarring as does the Baker sliding sleeve. The Halliburton sliding side door does feature an equalising port which allows the pressure inside and outside the sleeve to be equalised before jarring operations commence. The type XA and type XO are available for the smaller tubing size and are opened by jarring upwards or downwards respectively.

They differ in the seal configuration between the inner and outer sleeves. The type XD is available for larger tubing sizes.

The benefits of the sliding sleeve/door systems are that they provide a reasonably large cross sectional area for flow which permits acceptable circulation rates to be achieved without hydraulic erosion.

7.2 Side Pocket Tubing Mandrel with Injection or Shear Valve

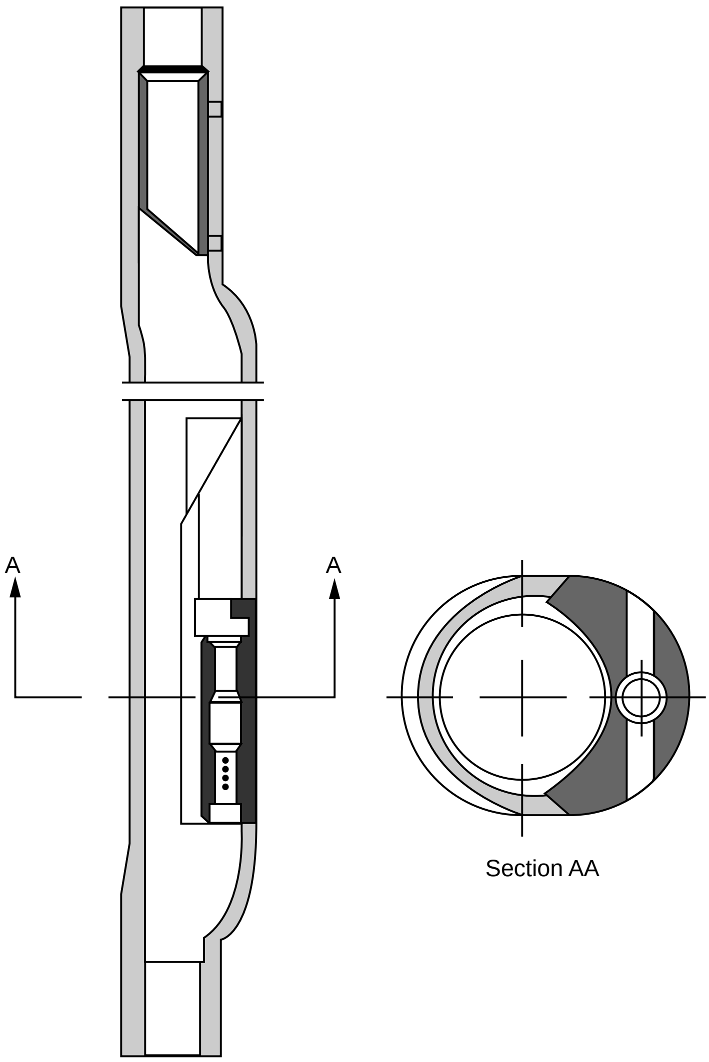


Figure 39
Side pocket mandrel SPM

The side pocket tubing mandrel consists of a tubing mandrel with ports located on its outside wall figure 39. Two basic types of mandrel exist:

(a) The side pocket mandrel where the pocket which will contain a wireline replaceable valve device, is located within the mandrel body.

(b) Conventional mandrel in which the valve is located external to the tubing mandrel.

1. Side Pocket Mandrels

Side pocket mandrels can be of round or asymmetrical oval cross section but at one side of the mandrel, an inner sleeve or pocket is located. This side pocket has ports in the outer wall of the mandrel through which communication between the annulus and tubing can be accomplished. Using wireline tools a variety of valve devices can be installed and retrieved. These valves have external seals which seal in the pocket above and below the ports hence annular communication is through the valve.

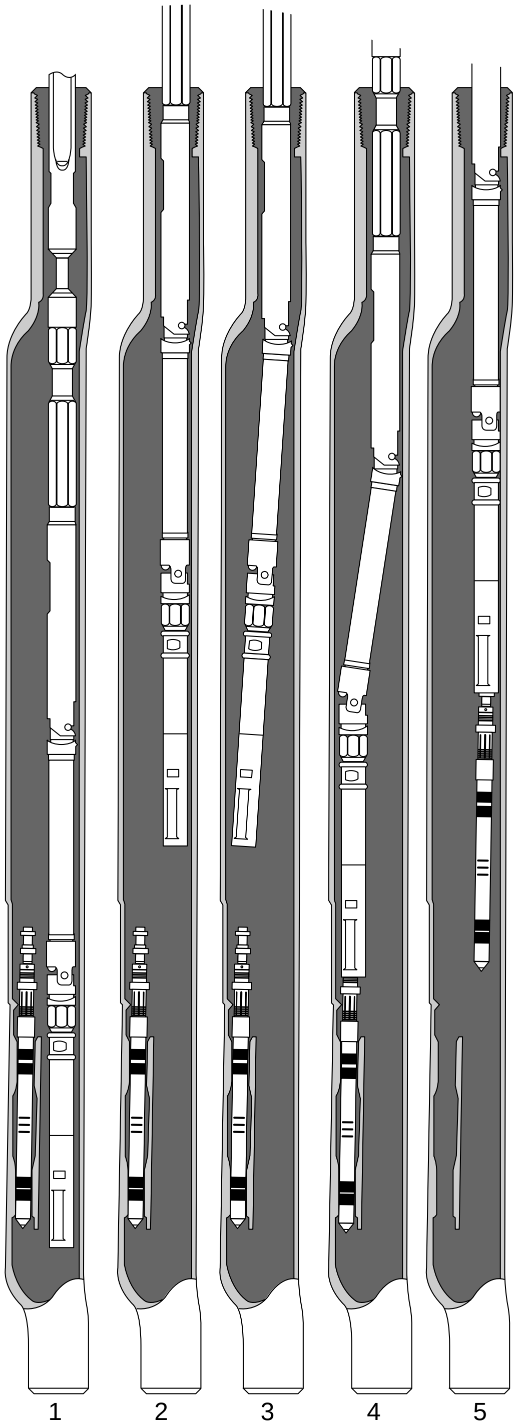


Figure 40
The setting and retrieving of a valve in an SPM

Some of the more common valve devices are:

(a) a fluid injection valve, which allows the injection of a chemical or gas from the annulus into the tubing. The valve opens by either reaching an absolute pressure in the annulus or a differential pressure between tubing and annulus.

(b) a shear valve, which has shear screws designed to shear under preset differential pressure conditions and hence provide communication. To seal off the ports after circulation requires the retrieval of the valve and its replacement with a new one.

The installation of valves, even in highly deviated wells can be accomplished using a kickover tool provided as obstruction exists in the entry area to the pocket. Figure 40.

2. Ported Nipples

These are constructed from a standard type of wireline nipple with a port drilled through the seal bore wall. During normal operation, the port is isolated by packing elements located above and below it on a mandrel placed within the nipple. To initiate communication the mandrel must first be pulled to reveal the ports.

SUMMARY

In this section, we have discussed the functionality requirements for and principal design features of downhole completion equipment such as:

- Production tubing
- Wellheads and trees
- Packers
- Subsurface safety valves
- Flow control and circulation devices

The concepts metallurgy and elastomer selection have been discussed.

In terms of materials selection the compromise between strength, cost, corrosion resistance has been discussed. The section has discussed equipment options on a functional basis stressing what the operational objectives or capabilities each item of equipment offers.

EXERCISE 1.
PACKER FORCE CALCULATION - HIGH GOR WELL

A well in the North Sea has been completed with 7" OD tubing (6.33" ID) inside 9 $^5/_8$" OD casing (8.625" ID). The tubing is latched into a permanent packer at 9000' TVD. The packer fluid in the annulus is $CaC1_2/CaBr_2$ brine of density 0.690 psi/ft.

When the well is closed in, phase separation takes place in the tubing resulting in the following static conditions:

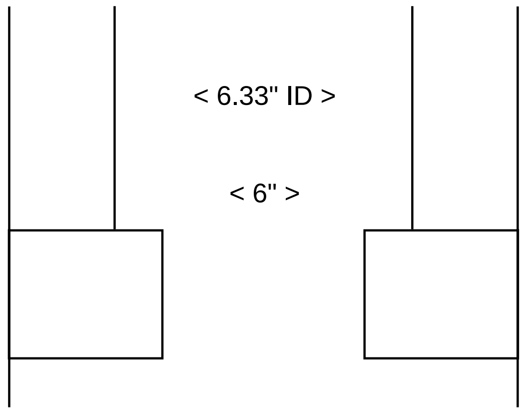
(a) THP = 2000 psig
(b) Gas column down to 4000' TVD, of density 0.15 psi/ft
(c) Oil column from 4000' down of density 0.375 psi/ft

When the well is flowing, the pressure just below the packer is reduced by 1000 psig because of both drawdown on the reservoir and vertical lift flowing pressure loss across the reservoir interval.

Calculate the imbalance of forces on the packer in both the static and dynamic phase.

EXERCISE 1. Solution
PACKER FORCE CALCULATION - HIGH GOR WELL

Simplified Schematic:



STATIC CASE

BHP at packer = 2000 + (4000 x 0.15) + (5000 x 0.375) = 4475 psi

Assuming packer is of negligible width:

Force upwards $= 4475\text{x}\,\frac{\pi}{4}\left(8.625^2 - 6^2\right)$

$$= (74.39 - 36)\text{x}\frac{\pi}{4}\text{x}4475 = 134861 \text{ (Upward)}$$

Force downwards = tubing force + annular force

$$= \frac{\pi}{4}\left(6.33^2 - 6^2\right)\text{x}4475$$

$$+(9000\text{x}0.690)\text{x}\frac{\pi}{4}\left(8.625^2 - 7^2\right)$$

$$= 14294 + 123775 \text{lbs} = 138069 \text{ (Downward)}$$

Resultant force = 3208 (Downward)

Pressure below the packer $= 4475 - 1000 \text{ psi} = 3475 \text{ psi}$

Force upwards $= 3475\text{x}\frac{\pi}{4}(8.625^2 - 6^2) = 104723 \text{lbs (Upward)}$

Force downwards $= \frac{\pi}{4}(6.33^2 - 6^2)\text{x}\,3475 + 123775$

$$= 11099 + 123775 = 134875 \text{ (Downward)}$$

Resultant force **= 3015 1 (Downward)**

C O N T E N T S

Learning Objectives:

Having worked through this chapter the Student will be able to:

- Describe the options, and their inherent constraints / advantages, for producing multiple reservoir units.

- Propose general completion schematic options for producing two, three or more zones simultaneously.

- Define the equipment requirements in terms of packers, tubing hangers and Xmas trees for multiple completion strings.

1 DEFINITION

Multiple zone completions are employed on reservoirs where more than one distinct reservoir layer is to be intersected by a single well and for which the intention or requirement is to produce/induce these layers separately. Normally the reservoirs are sequentially encountered as the depth increases. The concept of a homogeneous reservoir rarely, if ever, exists in reality. However, producing formations can often be considered stratified, and their producability depends upon the extent to which vertical flow occurs. Stratified reservoirs are created by changes in depositional conditions but the layers have different rock properties and hence flow characteristics e.g. permeability. The layers can have a variable degree of vertical communication. Alternatively, if the layers deposited by changes in depositional conditions are separated by deposited layers having very low or non-existent vertical permeability, each of the producing layers is a non-communicating reservoir layer.

2 MULTIPLE-ZONE DEPLETION CONCEPTS

The depletion of multiple zone reservoirs can be accomplished by one of the following:-

(a) Comingling the Flow from Various Zones:

In this approach, more than one zone flows into the tubing string, e.g. two zones producing up a single tubing string.

(b) Segregated Multi Zone Depletion:

With this approach the concept is to use multiple production conduits within the same wellbore, where each tubing is utilised for the production of one zone.

(c) Alternate Zone Well Completion Strategy:

Here the idea is to complete each well on one specific reservoir.

The advantages and disadvantages of each of the above techniques is discussed below.

2.1 Co-mingled Flow

2.1.1 Advantages

(1) Since each well provides a drainage point in each reservoir unit, the total number of wells is a and the capital investment, is therefore minimised.

(2) Since the amount of drilling is minimised, the production plateaux for all the reservoirs should be reached as quickly as possible. i.e. production should be accelerated compared to the other optional strategies

2.1.2 Disadvantages

(1) The mixing of produced fluids in the wellbore can be disadvantageous if one or more fluids have any of the following characteristics:

(a) Corrosive or potentially corrosive materials e.g. acids, H_2S, CO_2.

(b) Produced sand and a potential erosive effect. The implementation of sand control procedures may be more complicated.

(c) Fluids having different Hydrocarbon compositions and hence economic value.

(d) Different WOR and GOR as this would influence the vertical lift performance of the total well system.

(2) Variation in individual zone pressures and permeability can lead to a back pressure effect on the less productive or lower pressure reservoirs.

(3) The use of co-mingling removes the capability for continuous control of the production process, i.e. closure of one individual zone cannot necessarily be effected unless a relative configuration is used.

(4) Injection of fluids, e.g. stimulation fluids cannot easily be diverted into individual layers without temporary isolation using sealants (diverters) or bridge plugs.

(5) A change in the production characteristics of one zone e.g. water coning and a consequent increase in WOR, will influence the total production from the well but may be difficult to remedy without closing in the well.

2.2 Segregated - Multiple Zone Depletion

2.2.1 Advantages

(1) The production rate and duration of flow on each zone can be independently controlled.

(2) Changes in the production characteristics of one zone will not influence the others.

(3) Some remedial work on individual zones can be accomplished without always affecting production on other zones, e.g. cement squeeze, reperforating, perforation washes.

(4) Stimulation on each zone can be applied.

(5) Continuous monitoring of the depletion of each zone can be achieved, which assists in material balance or reservoir simulation studies for reservoir management.

2.2.2 Disadvantages

(1) Since each zone has a tubing string the amount of production tubing and other completion equipment required is considerable. This requires additional capital and installation time.

(2) The mechanical complexity of the completion is increased and hence the possibility of equipment malfunction is also increased.

(3) The amount of completion equipment is increased and hence the statistical possibility of component failure is also increased.

(4) The retention of tubing sizes may reduce the total flow capacity of the well

2.3 Alternate Zone Well Completion Strategy

2.3.1 Advantages

(1) Effective control of all aspects of reservoir depletion and well control is provided.

(2) Changes are easily introduced to adapt to variations in the depletion strategy, e.g. changing a well from production to injection.

(3) Problems encountered on one well does not necessarily influence the continuity of the production of fluid from other zones/wells.

(4) Each well is relatively simple mechanically and the risk of failure due to complexity is minimised.

2.3.2 Disadvantages

(1) To achieve the same degree of depletion control by having good reservoir drainage, the number of wells to be drilled and completed must increase in total. Thus, the total cost of such a development will be substantially increased to achieve the same drainage effiency in the reservoir.

(2) Unless the number of wells is increased, the difference of production on some zones will defer, reduce and extend the field of life thus increasing unit production costs.

2.4 Selection of Development Strategy

The chosen strategy for the completion and development of a reservoir drainage system, will depend very largely on the following:

(1) *Offshore or Onshore Development*
In an offshore development, the cost per well is so large that the planned number of wells is usually minimised. This limitation will not be as significant in an onshore development.

(2) Areal Size and Number of Reservoir Zones
The drilling of a large number of wells can be more easily accomplished with or without directional drilling on land. Offshore, however, if the structure covers a very large area, the use of very high angle wells will be necessary. To run very complex multiple completions in high angle wells can lead to significant difficulties being encountered.

(3) Variation in the Reservoir Rock and Fluid Characteristics
The degree to which corrosion or erosion is likely to occur will influence the type of completion. In addition the degree to which drawdown on one zone might suppress production from other zones may be important.

The flow potential of each zone might be impaired if too small a tubing size is used, because of the lack of space within the wellbore for a multiple tubing completion.

3 MULTIPLE ZONE COMPLETION CONFIGURATIONS

Wells can be completed on any number of zones within the same well by simply increasing the amount of completion equipment installed to provide isolation and flow control capability. The benefits of using the same wellbore for multizone production are significant, but as the number of zones increases, the complexity and potential for malfunction can negate the inherent advantage of the single wellbore completion. The optimum number of zones to be produced into any wellbore will depend on the reservoir, e.g. in high rate, highly deviated completions, perhaps even two tubing strings might not be desirable. In other cases three tubing strings in each wellbore might be used to deplete a number of zones.

3.1 Dual Zone Completion
There are a number of ways in which completions can be designed to produce two zones. Besides co-mingled flow and individual well/zone completion there are:

(1) Casing/Tubing Flow
In this case a single tubing string is run with a single packer installed to provide isolation between zones. One zone will produce up the tubing, whilst the other will produce up the casing-tubing annulus.

The difficulty with this type of completion is that under natural flow conditions it will have a live annulus perhaps necessitating an annular safety valve. Also the produced fluid is in contact with the casing and it may thus cause damage by corrosion or abrasion. In addition, pressure limitations on the annulus with respect to casing burst may preclude stimulation of the zone which produces via the annulus.

Two alternative completion types exist:

(a) Upper zone annular flow - applied where the upper zone fluid is non-corrosive, non-abrasive and where pressure limitations of the casing would not preclude stimulation.

(b) In situations where the upper zone would not be suitable for annular flow, then a lower zone annular flow system could be used requiring one tubing string, two packers and a crossover tool. This design however, severely precludes mechanical areas to both zones for logging, perforating etc..

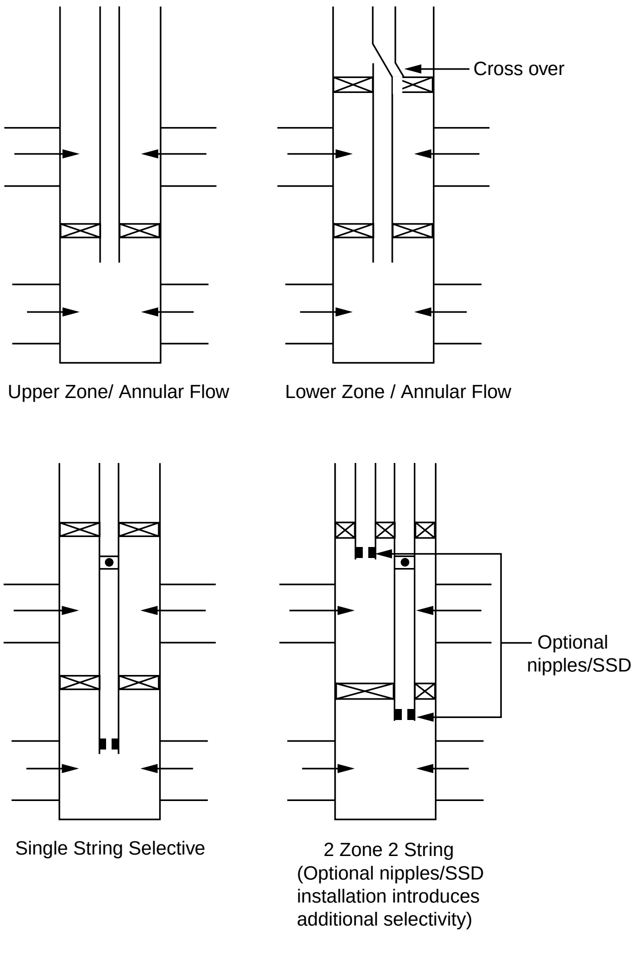


Figure 1
Options for 2 Zone Flow without Comingling

(2) Dual Tubing Flow

In this type of completion a separate tubing string for each zone is provided with two packers, one to isolate between zones and the other to isolate the upper zone from the upper casing annulus. Here the depletion of each zone can be accurately monitored and controlled. In addition, the injection of fluids into each zone is limited only by the tubing design criteria. Also, the completion is more suited to the effective production of problem well fluids.

(3) Single String Selective Producer

In this completion, the well is completed over two zones, utilising one tubing string designed to selectively allow the production of either or both of the zones. The completion requires two packers, one to isolate between zones and the other to isolate the annulus. In addition, an entry point for fluid from the upper zone to enter the string must be provided which can be opened and closed as desired, e.g. a sliding side door. Finally, when producing the upper zone into the tubing, closure of the lower zone may be accomplished by setting a plug in a nipple at the base of the tailpipe.

3.2 Completions for 3 or More Zones

The available options discussed in section 3.1 for dual completions can be extended for wells to be completed on three or more zones with or without some degree of zonal co-mingling.

(1) Triple Zone Completions

This can be accomplished with either:

(i) A completion utilising separate zonal flow into one of three tubing strings and having three packers for isolation.

(ii) A two string completion, whereby flow from two zones is co-mingled into one of the tubing strings.

(iii) Single zone annular flow and two tubing strings producing separately from two zones.

(iv) Two string completion where either or both of the strings are completed to allow selectively production from two of the zones. This requires two tubing strings and three packers.

(v) Single string, triple zone selective completion.

(2) Four or More Producing Zones

Normally no more than three strings are run into the wellbore, but a large number of options exist.

(1) Single string selective producer.

(2) Dual string selective producer.

(3) Dual string/selective with annular production.

(4) Triple string with annular production.

(5) Triple string with selective production.

It is clear that when four or more zones exist, the completion strings can become complex, costly, difficult to run and retrieve, and more likely to produce mechanical failure. The considerations can severely impact on the life of the well.

4 MULTIPLE COMPLETION EQUIPMENT

In general terms, equipment requirements for multiple completions are largely based upon the equipment available for single string completions with the following exceptions:

(a) tubing hanger systems
(b) tubing packer systems
(c) specialised installation equipment.

Obviously the number of tubing strings will affect the completion procedure. However, since the sizes of the tubing and hence ancillary equipment are dictated by the limitations imposed by the casing inside diameter, tensile load and torque capabilities will not normally be a significant problem for a completion rig.

4.1 Tubing Hanger Systems

Here the difficulty is one of landing off the tubing in the landing seat in the tubing head spool. The simplest way of achieving this is to use a segmented hanger. For each tubing string a hanger segment is produced. Upon landing off all the tubing strings, the hangers should form a composite circular hanger which also seals the annular space in the landing seat within the tubing head spool. Normally each hanger segment is made up with a tubing pup joint above and below which is attached to the rest of the string. The tubing strings are either run independently or simultaneously.

When using a surface controlled sub-surface safety valve, provision must be made for the control lines for each tubing string and valve system.

4.2 Multiple Tubing Packer Systems.

In a multiple tubing systems, the number of packers will normally equal the number of zones to be produced. For a dual zone, dual tubing completion, two packers will be required, the lower being a single packer whilst the upper will be a dual packer. Similarly for a three zone, triple tubing completion, three packers will be required, comprising a single, dual and a triple packer.

Multiple string packers are available to similar specifications as single string packers, i.e. they can be either permanent or retrievable. In addition, they can be set using a hydraulic or a mechanical setting procedure. The wireline setting procedure, although frequently used to set the lower single string packer, would find little application for the upper packer(s) because of the cable weight limitations.

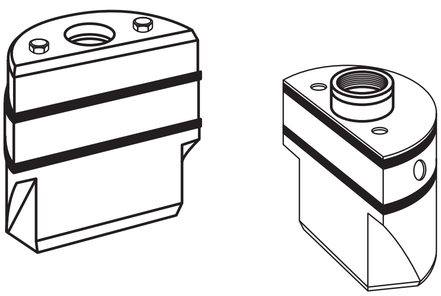
All multiple string packers must offer a means of connecting tubing above and below the packer for each string. In some cases mechanical attachment exists e.g. tubing screwed onto the base of the packer whilst, in other cases, the packer offers a seal bore.

In any completion involving multiple strings, the tubing strings will have different lengths and are denoted as the long string, intermediate string and short string. This terminology is crucial to the running procedures for the completion, e.g. a packer may be run into the well on the long string which is landed off, and may be set using hydraulic pressure either by the long string or by the short string after it has been run, located into the packer seal bore and landed off in the THS.

Although in most cases it is preferable to run retrievable multi-string packers since it leads to easier retrieval in an already more complex workover operation, permanent packers are available and may be required in high pressure wells, or where significant tubing movement and stress is anticipated. One example of such a packer in the Baker model DE available for either hydraulic setting DEH, or for setting on tubing or wireline the model DE-1. This packer is based on the model D packer having the same design principle of full circular slips and metallic back up rings. The packer offers two seal bores whose length can be extended up to 20 ft. If the packer is set on wireline, then the long string would be run through the upper seal bore and down into the seal bore or latched into the lower packer. The long string can then be pressure tested prior to running the short string. With the hydraulic version, the packer with the long string tailpipe is made up and run on both the long and short tubing strings. After landing off, a ball is dropped down onto an expendable seat in the base of the packers and pressure of for example, 3000 psi seats the packer and 4000 psi shears out the ball and seat.

A dual version of the A-5 packer is available from Baker, which is set by pressure created in the short string. A modified version termed the AL-5 is the same packer, but can be set by pressure in the long string. To allow pressure testing of the tubing without premature setting of the packer, a modified ALS-5 packer is available from Baker.

Halliburton have a range of hydraulically set, retrievable packers, termed the RH range. The RH packer has been discussed previously, but Halliburton also offer the RDH and RTH for dual and triple completions respectively. The packers can be set by hydraulic pressure in either the long or short string



Figures 2
Dual Completion-split hanger

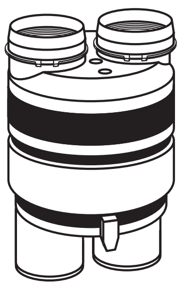


Figure 3
Dual tubing hanger - integral

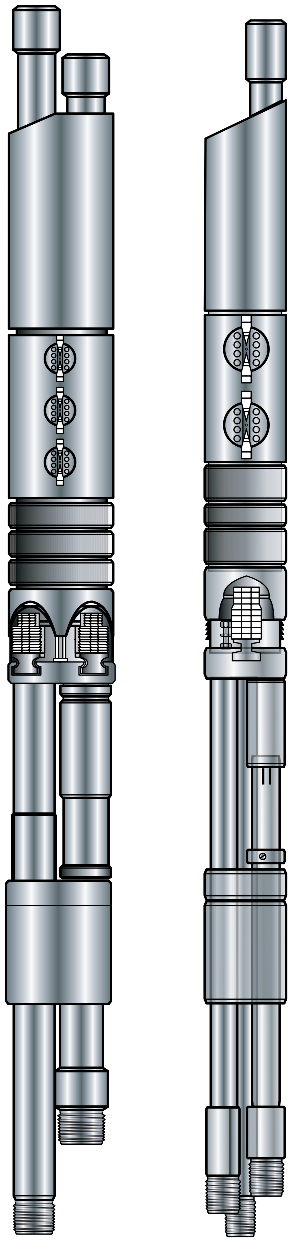


Figure 4
Hydraulic Set Packers; dual and triple configuration

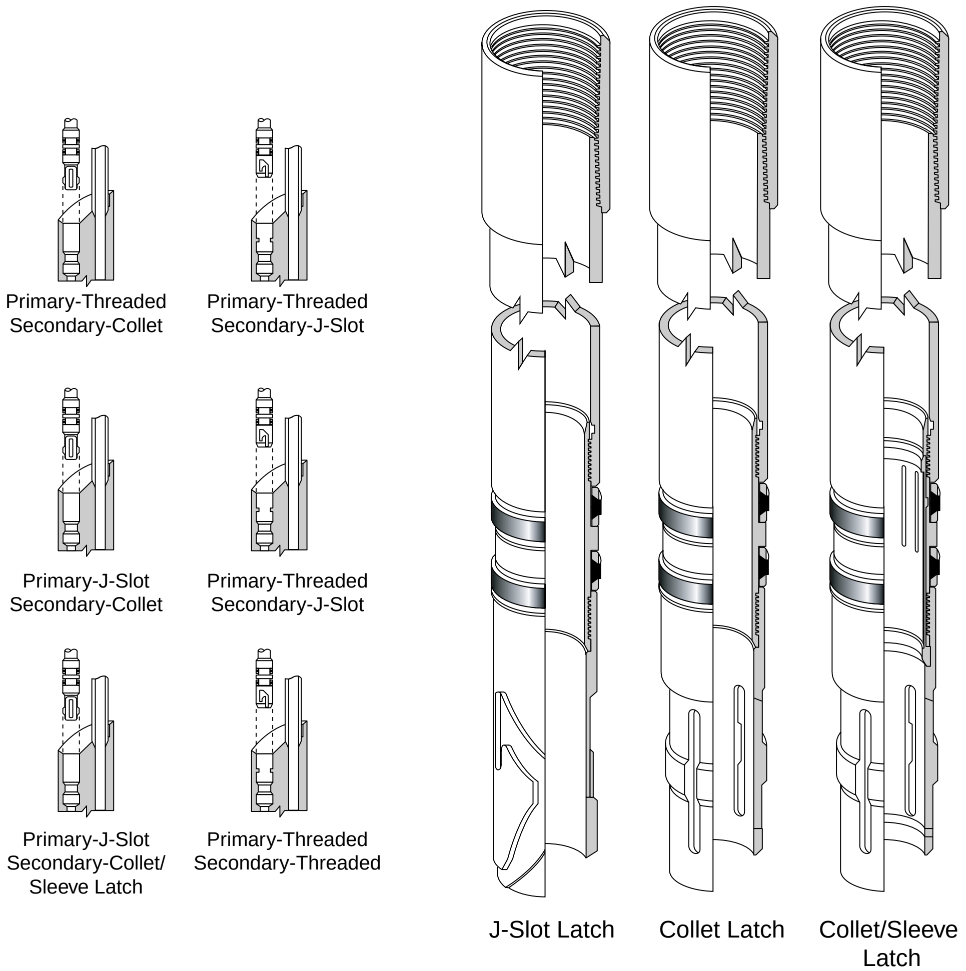


Figure 5
Seal Assemblies for Hydraulic Set Packers

Since the packer is normally run on the long string, it is possible to set the packer with the long string in tension, but the short string can be set in either tension or compression.

Once the packer has been run to the desired depth and the long string landed off, the short string is run and landed off within the second seal bore of the packer. A ball dropped down the desired setting string, lands in an expendable seat (1). Internal hydraulic pressure from the tubing shears the pins (2) by the downwards movement of the setting piston. The downwards movement of the setting mandrel expands the lower element and sets the slips. Upon releasing the tubing pressure, the packer is held in the set position by internal slips (3). Differential pressure from below the packer sets the hydraulic hold down buttons. To retrieve the packer, the short string is first retrieved, and upwards tension will shear the pins (5) and allow retrieval.

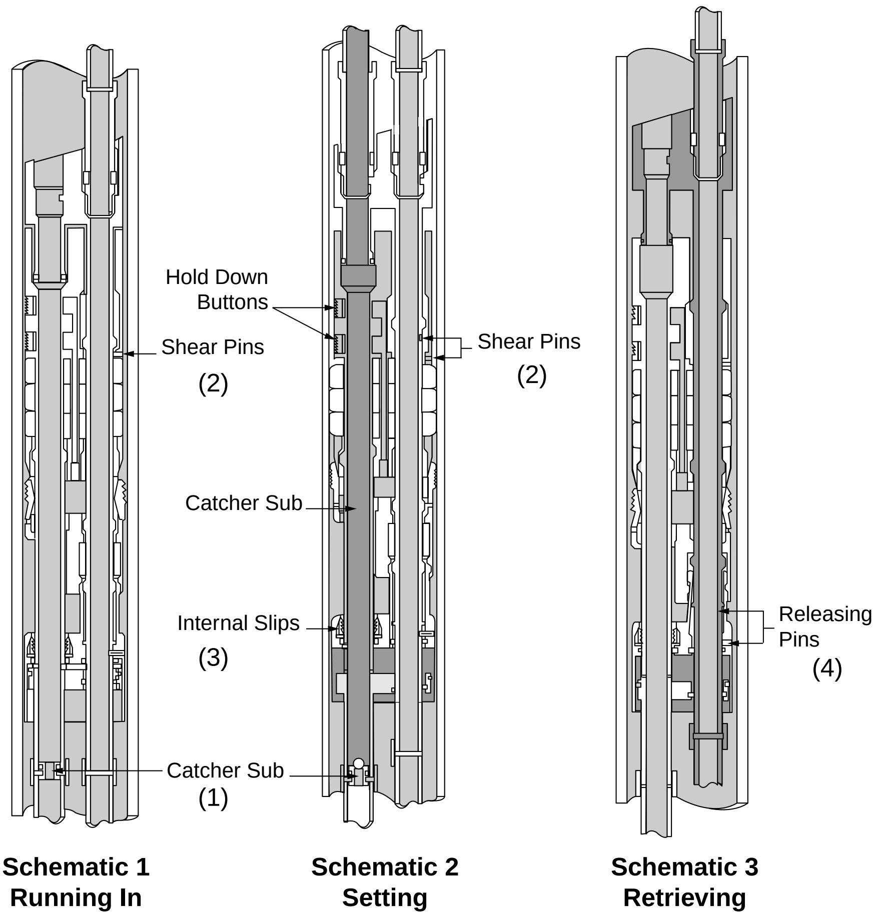


Figure 6
Running, Setting and Retrieval Operations for typical dual hydraulic set packer

Mechanical set dual or triple packers are also available. The packer utilises a weight set concept (3000 - 5000 lbs) and can be set by either the long or short string. In addition, if a J latch system is used for both strings, each string can be retrieved independently for workover without unseating the packer. The packer is available as either short string or long string, set with or without hydraulic holdown, e.g. SH/SA and LH/LA. The setting concept is useful since no tubing rotation is required.

Four different connecting systems are available for engaging the short and long string into the packer:

(1) Threaded connection - this could be used for two strings if both strings were to be run and pulled together. Normally, it is simpler to pull the strings individually.

(2) J-slot connector - requires 1/3 right hand turn at the packer for release.

(3) Collet connector - requires no rotation.

(4) Collet-sliding sleeve latch - this is an adaption of the collet connector where an inner sleeve is fitted and this has to be shifted to lock and unlock the collet.

5 AUXILIARY EQUIPMENT FOR MULTIPLE COMPLETIONS

(1) Circulation sleeves

A useful item for dual completions in a pressure operated sliding sleeve which allows easy circulation of fluids between long and short strings or between the long string and the annulus. This facility removes the necessity to remove the tree in order to disconnect the string latches prior to circulating the well to kill or initiate production. The tubing can, in fact, be landed off and the well circulated prior to setting the packer. The opening of the sleeve requires about 600 - 800 psi differential pressure in the long string. It may be necessary to have a ball and expendable seat below the packer in the long string to protect the lower formation against the pressure generated in the tubing. After circulation, a ball dropped down the short string lands in the expendable seat, and pressure applied to set the packer also closes the circulation sleeve.

An alternative pressure operated circulation sleeve uses internal pressure to open the sleeve but after use, a ball is dropped down the tubing and lands in a recess. With the application of tubing pressure the inner sleeve is moved downwards and the device closes. In operation it requires about 650 psi internal pressure to shear the screws on the lower sleeve and this allows the spring to push the lower sleeve down and exposes the ports. After circulation, the ball is dropped down and once in position a pressure of 2900 psi will be required to shift the upper sleeve down and close off the ports.

(2) Blast Joints

The long string in a multiple completion is located in the casing opposite the perforated sections of upper producing zones and as such they are present in the section of the wellbore where fluid entry occurs. The direction of fluid low through the perforations into the wellbore is normally perpendicular to the well axis and the fluid flowstream must quickly change through 90° to flow up the tubing. The fluid entering the wellbore may have a significant impact force on the tubing wall of the long string and will lead to hydraulic erosion. If sand or solid fines are being produced, they will drastically increase the erosion rate.

Accordingly, to compensate for the increased erosion, a thick walled tubing section known as a blast point is normally included in the string opposite the perforated intervals of the upper production zones.

SUMMARY

In this section we have discussed the options and equipment requirements for completing multiple zone reservoirs. In most cases we must balance the reservoir management requirements in terms of flow control, regulation and isolation as again the additional complexity and its inherent costs - both capital and intervention, as well as operational constituents.

In some situations the complexity can also limit production rates due to the number of tubings within a fixed size of casing and the consequent need to use smaller tubing diameters.

C O N T E N T S

LEARNING OUTCOMES

Having worked through this chapter the student will be able to:

- Describe the options and their advantages and disadvantages for perforating oil and gas wells.
- Describe how to select between over balance and under balanced perforating.
- Describe how to define an outline strategy to complete a well as part of a completion operation.
- Understand the importance of charge design and what factors influence performance.
- Identify draw down condition to be specified.
- Discuss the importance of protecting perforations against leak off and damage during completion and work over operations.

INTRODUCTION

In the majority of completions, once the reservoir has been drilled, production casing or a liner is run into the well and cemented in place. To provide the communication path between the reservoir and the wellbore, it will be necessary to produce holes through the wall of the casing, the cement sheath and penetrate into the formation. This is accomplished by a technique called perforating.

The basic operation requires that a series of explosive charges are lowered into the well either on an electric conductor wireline cable, or on tubing or drillstring, and when the charges are located at the required depth, they are detonated to produce a series of perforations through the wall of the casing and the cement sheath.

Since the perforations will hopefully provide the only communication between the reservoir and wellbore, it is necessary to carefully design and execute the perforating operation, to provide the required degree of reservoir depletion control and maximise well productivity/injectivity.

Initially, the type of charges used in perforating guns were bullets, but with the development of armour penetrating explosives during World War II, shaped charges or jet perforators are now almost exclusively used.

1 SHAPED CHARGE CHARACTERISTICS AND PERFORMANCE

A considerable amount of research has been conducted through the years into the mechanics of the detonation of shaped charges and the subsequent penetration of the target. A large number of design parameters, as well as operational conditions, can markedly effect the performance of shaped charged perforators.

1.1 Principles of Shaped Charges

The basic shaped charge consists of:

(1) A conical metallic liner

(2) A primer explosive charge

(3) The main explosive charge

(4) A charge case or container

The components are depicted in Fig 1.

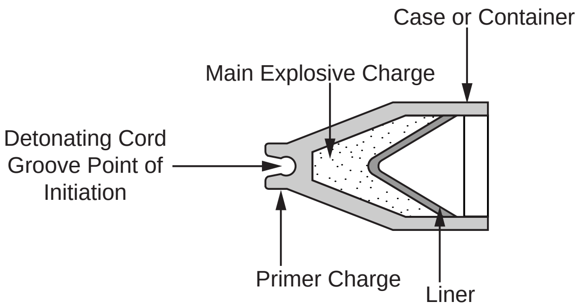


Figure 1
Shaped charge

The main explosive charge is usually a desensitised RDX (Cyclonite) type of explosive which besides being extremely powerful in terms of the energy released per unit weight of explosive, also reacts very quickly. In fact, once the main charge is detonated the process is completed after only 100 - 300 µ seconds. This fast reaction time is of importance in that it concentrates the detonation energy of the exploding charge to a very limited target area and also excludes any thermal effects.

The main explosive is contained within a charge container which can be manufactured as either a metal or a disintegrateable case e.g. ceramic which will be shattered during the explosion. Whilst a metal case would assist in containing and directing the force of the explosion to a certain target area, the target area would be diffuse as it would depend upon the diameter of the exit area for the explosion from the charge case and its distance from the target area. To concentrate the impact of the explosive force on the target the charge case is normally designed with a conical liner. This conical liner assists in concentrating the explosive force of the charge so that it provides maximum penetration of the target over a limited area as illustrated in Fig 2. From Fig 2, it can be seen that if a flat end is used for the shaped charge, the force of the explosion is spread over a wide area of the target with very limited penetration. However, if a conical cavity is introduced, the force of the explosion provides much greater penetration of the target. However, if the conical cavity is lined with a metallic liner, the penetration is substantially increased.

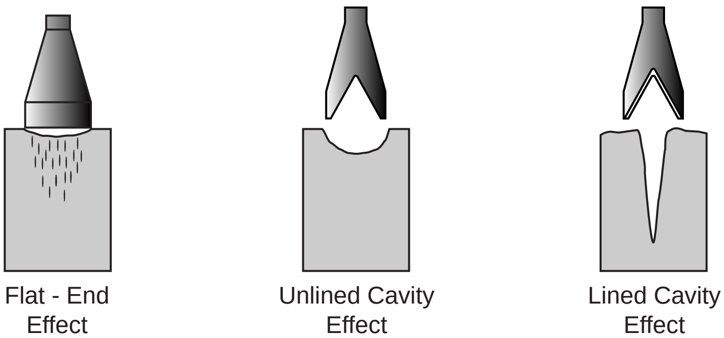


Figure 2
The importance of using a conical liner in a shaped charge

To understand more clearly how the use of a metallic liner can influence the penetration in this way, it is necessary to consider in more detail the actual mechanics of the explosion. The detonation is actuated from surface by either electrical current in the case of a wireline conveyed gun or by mechanical, hydraulic or electrical means if the gun is conveyed on tubing. First, the primer charge is detonated and this in turn fires the main charge.

On detonation of the main charge, a detonation wave is produced which moves from the apex of the charge container at a speed estimated to be 30,000 ft/sec. This explosive detonation wave exerts pressures of up to 2-4 x 106 psi against the liner which then starts to deform. The material of the liner on the outside flows towards the centre of the cone to form a jet of fluidised material, whilst the material of the cone initially in contact with the explosive charge, collapses inwards towards the central axis of the cone, to produce a slug or tail of fluidised material. The relative distribution of the material between the jet and the slug is $^1/_3$ and $^2/_3$ of the total respectively, Fig 3.

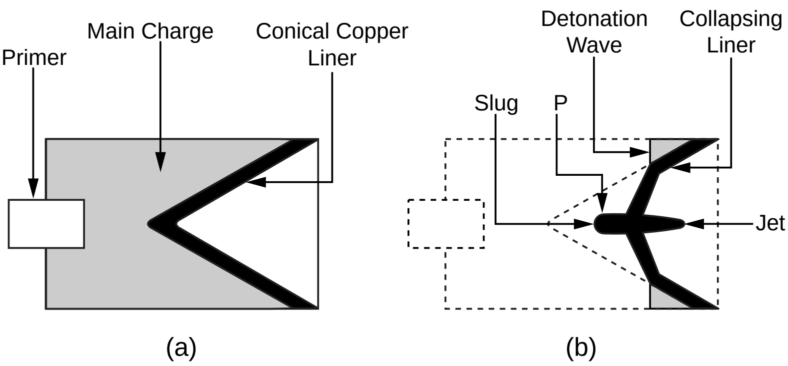


Figure 3
Detonation process and deformation of the conical liner

The jet leaving the charge has a velocity of the order of 20,000 ft/sec. and has an impact pressure on the casing of 5 x 10^6 psi. Under such high impact pressures, the casing material that it contacts, becomes plastic and moves away from the impact of the jet. The material in the formation will be compacted and moved back into the formation ahead of the jet as the tunnel is created through the casing and cement sheath into the formation. The whole process takes place almost instantaneously and since no thermal effects take place, no fusion or burning occurs. The penetration is due solely to the extremely high impact force exerted on the target by the jet.

The jet, whilst it is being created over an interval of a few microseconds starts to extend and move away from the charge. However, the slug material, although it comprises the bulk of the mass of the liner will lag behind the jet and in fact plays no real purpose in creating the perforation. On the contrary, the material of the slug will follow the jet into the perforation where, due to its mass, it will be deposited, thus giving rise to plugging of the perforation. The presence of the slug is therefore detrimental to the subsequent flow performance of the perforation. One approach to eliminate the slug has been to create a bi-metallic liner system, where the inside surface of the cone which will produce the jet is composed of copper whilst that on the outside is a metal, such as zinc, which will readily vapourise during the explosion, figure 4.

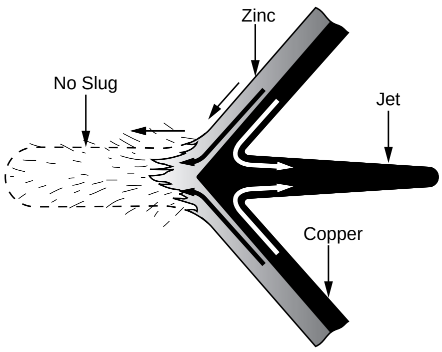
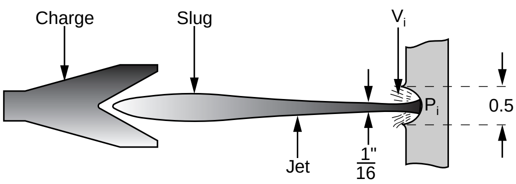


Figure 4
Schematic of bimetallic liners deformation

It is therefore clear that the penetration process is controlled to a large extent by the characteristics of a jet moving at very high velocity which impacts on the target material. The area of the target affected will be directly proportional to the diameter of the jet produced. Since the depth of penetration is directly influenced by the speed of the jet, it is evident that it is of paramount importance to maintain the jet at a minimum diameter Figure 5



¥ Pressure On Target - $P_i = 5 \times 10^6$ PSI
¥ Velocity Of Forward Jet - V_i = 20,000 Ft./Sec.

Figure 5
Perforating jet characteristic and properties at impact with the target

The impact of the perforating jet upon the formation it penetrates is one of compaction of the rock which it encounters. Since the rock is not vapourised, it will be merely pushed back into the formation around the perforation tunnel it creates. The material will be crushed and compacted. The consequent perforation tunnel and surrounding formations will thus consist of several zones in which the natural state of reservoir rock has been changed as depicted in Figure 6. The zone immediately adjacent to the perforation tunnel will consist of a layer of compacted and crushed formation grains and will possess a permeability substantially lower than the original reservoir permeability. Adjacent to this layer will be a series of layers in which the rock will have been overstressed resulting in a combination of micro-fractures and grain compaction and breakage. These layers referred to as the crushed zone will extend to a radial depth of the order of $^1/_2$ inch around the perforation tunnel wall. The permeability has been estimated to be of the order of 20% of the original permeability.

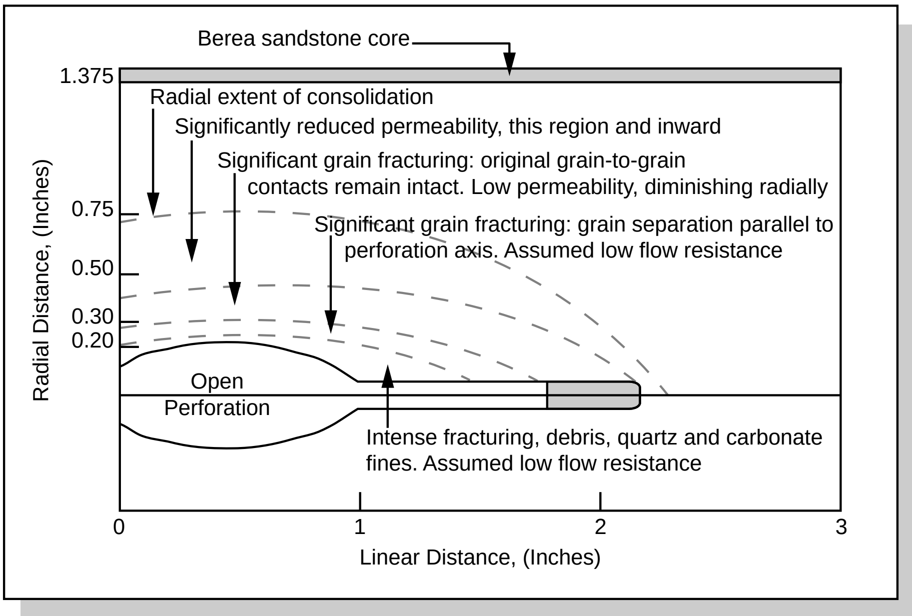


Figure 6
Crushed zone and compaction regions around the perforation tunnel

However, the properties and extent of the crushed zone will depend upon a number of factors including:

(1) Size of perforation charge

(2) Casing wall thickness and strength

(3) Cement sheath thickness and strength

(4) Grain composition, size and shape of the formation rock

(5) Stress conditions in the near wellbore region

(6) Proximity of nearest perforations in the same vertical plane.

1.2 Factors Influencing Charge Performance

The physical performance of a shaped charge is normally gauged from a number of characteristics:-

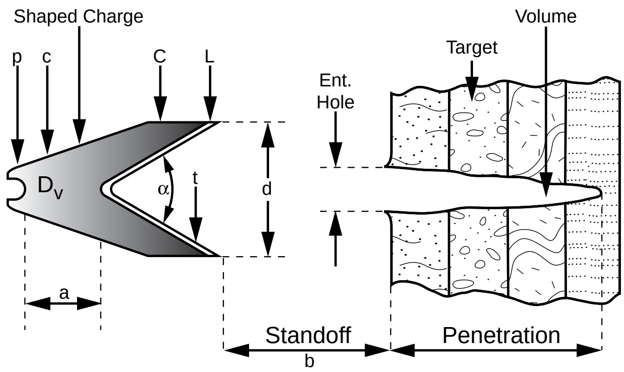
(1) Penetration length

(2) Perforation diameter

(3) Perforation hole volume

(4) Burr height on the inside of the casing around the perforation entrance hole.

However, charge performance will be a complex matter since it will be affected by charge size, material and configuration, the dimensions and shape of the charge case and most importantly the characteristics of the conical liner as shown in Figure 7 as well as the strength characteristics of the formation and the wellbore conditions.



To Increase:
Penetration - reduce α, increase b, a, d, t, C, and D_V
Entrance hole - increase α, d, reduce b, t, and D_V at apex
Hole volume - increase α, d, t, Reduce b, adjust D_V and L within charge

Figure 7
Factors which influence shaped charge performance

It would, therefore, be expected that the following parameters may influence the physical performance of the shaped charge:-

(a) Gun size/explosive charge size

The size of the perforating gun will dictate the maximum explosive load which can be accommodated in the charges.

In general terms, both the penetration and the diameter of the entrance hole will increase as the gun diameter and hence the size of explosive charge also increase as shown in Figure 8.

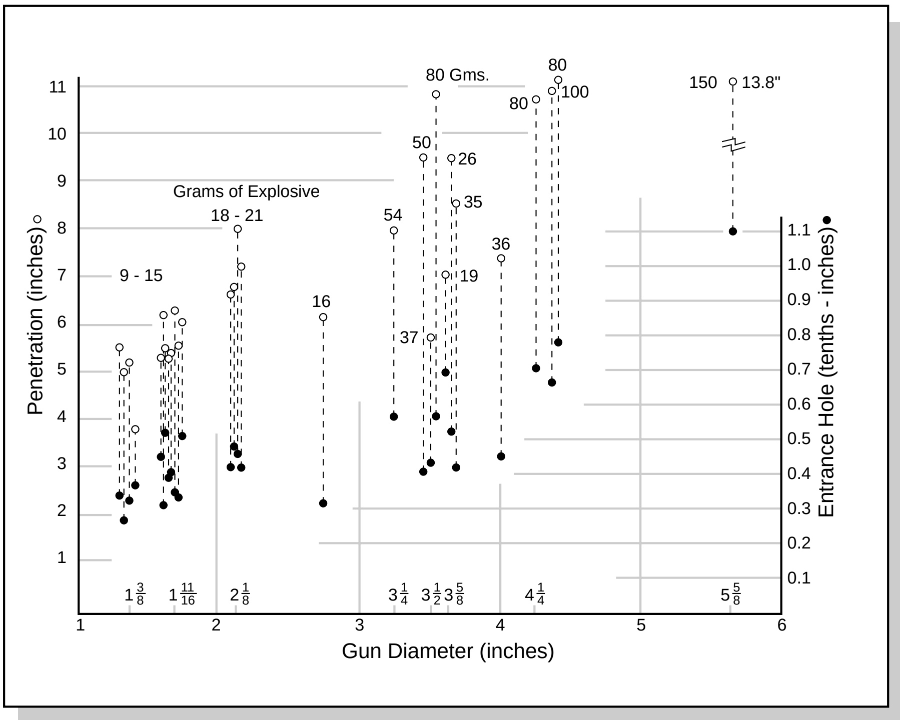


Figure 8
Effect of gun size on entrance hole diameter and depth of penetration

(b) Wellbore fluid pressure, temperature and density

It would be expected that if the fluid in the wellbore were very dense, then it could reduce the jet velocity and impair its physical performance. However, in reality the thickness of the fluid film through which the jet moves is normally small. If however the charge size is small or the gun clearance is large, penetration could be reduced.

Similarly well pressure has shown no observable effect on charge performance. This is particularly important given the frequent use of reduced hydrostatic pressure in the wellbore whilst perforating in an underbalanced mode. The effect on flow performance is much more important. However, elevated well temperatures can lead to significant degradation of the charges with consequent poor performance. However, the effect is only serious in deep hot wells where the gun contact time is large. In such situations, the protection of the explosive charges by their inclusion in a hollow gun carrier is advisable.

(c) Gun clearance

Since all perforating guns have a diameter which is substantially less than the casing inside diameter it follows that the gun cannot be expected to be centralised. If the charges are loaded on a design which calls for them to fire at different angular phasings then each charge will face a varying gap between the gun outside diameter and the inside diameter of the casing. This gap is known as “gun clearance”.

The effect of gun clearance upon penetration and entrance hole size is shown in Fig 9 for a simulated perforating configuration. It can be seen that maximum entrance hole size is achieved with a gun clearance of $^1/_2$ inch (normally provided as a defined stand off in the gun) but in general both penetration and entrance hole size decrease with increasing clearance.

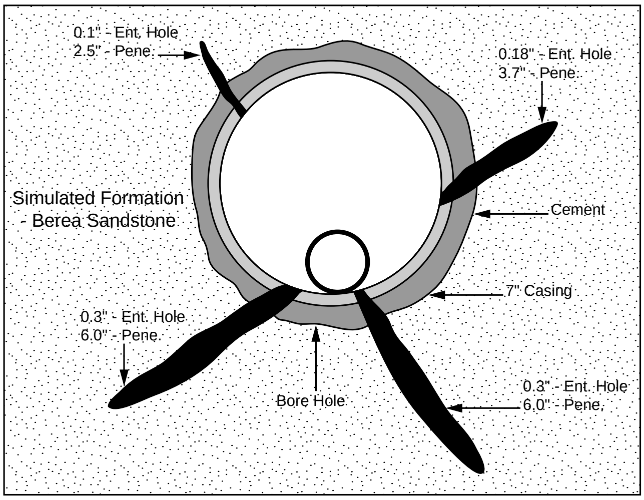


Figure 9
Typical result of perforation with 1 11/16" through tubing gun in a deviated production casing

The effect will be most serious when a very small diameter gun is used as is the case with wireline conveyed through tubing guns where the gun size is selected to pass through the completion string. In such cases it might be preferable to place all the charges to fire in-line and align the gun in the casing using a positioning device, to provide minimum gun clearance.

(d) Compressive strength of formation rock

It would seem logical for the compressive strength of the rock to have a large effect on the physical performance of jet perforators. Although the effect is not clearly quantified, the perforation obtained is inversely proportional to rock compressive strength as shown in Fig 10. It will be necessary to extrapolate test firing results obtained from a standard test material to specific reservoir rocks.

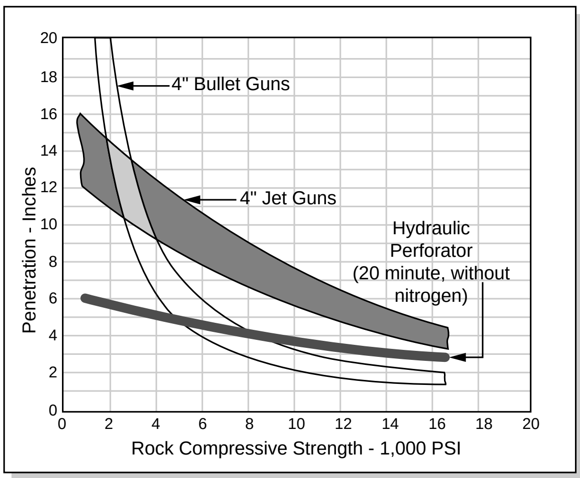


Figure 10
Penetration reduction produced by high compressive strength of the formation rock

(e) Strength of casing and radial support of cement sheath

If the casing to be perforated is constructed from high grade tensile steel, it will absorb more energy whilst being perforated and hence reduce the overall length of the perforation. In reality, the effect is relatively small.

However, as the number of perforations shot into a casing increases, the structural integrity of the casing is reduced and the possibility of splitting the casing cannot be discounted. This will be a very serious consideration where the cement sheath is incomplete, as perforating a casing, behind which no cement exists, could give rise to casing rupture.

1.3 Perforation Charge Arrangement

In the preparation of a perforation gun, a number of charges are assembled on a carrier such that upon detonation they will yield a series of perforations into the formation. The arrangement provides for variation in the number of shots to be fired per unit interval, i.e. the shot density and the direction in which all, or individual, charges will be shot, i.e. the shot phasing.

The number of shots installed in a perforating gun varies from low shot density, e.g. less than 1 shot/ft, to higher shot densities of up to 16 shots/ft. The lower shot densities are normally adequate for production in reservoirs of moderate to high productivity or are selected for specific injection operations where flow control is required. The higher shot densities will provide improved inflow performance in all reservoirs but may only be significantly beneficial in reservoirs with a low vertical permeability or where severe local drawdown might give rise to formation sand collapse.

The orientation of perforations defined as the angular phasing can be:

(a) 0° or in-line firing which can provide the minimum clearance for all perforations if the gun is positioned to fire on the low side of the hole.

(b) 45° to 90° phasing which provides the nearest approximation to radial flow.

(c) 180° phasing in either of the two planar directions.

(d) 120° phasing either with all 3 shots firing at 120° to each other or omitting 1 charge such that the 2 shots fire at +60° and -60° angular phase.

The phase orientations are depicted in Figure 11. All perforation flow patterns are utilised. 90° phasing which provides the best radial depletion can be very effective when conducted with high shot densities. However, the selection of phasing will depend not only on shot densities but gun size, gun clearance, formation isotropy or anisotropy with respect to permeability. It is clear that for each shot density a number of options regarding phasing can exist, for example, 4 shots/ft can normally be fired at 0°, 90° or 180° phasing (Figure 12).

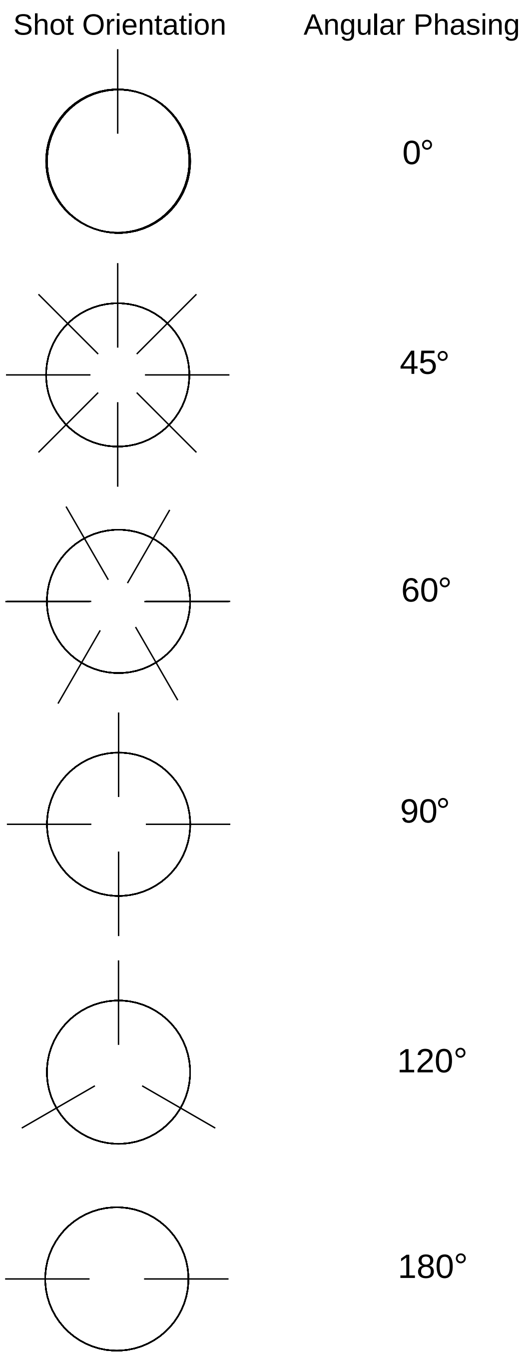


Figure 11
perforation shot phasing pattern

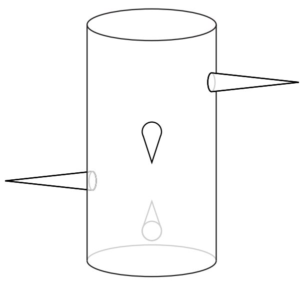


Figure 12
Perforation shot density: Example of four shots/foot in line firing and 90º phasing

2 THE ASSESSMENT OF PERFORATING CHARGE PERFORMANCE

2.1 API RP. 43 Fifth Edition - Standard Tests

There are a large number of companies who offer a perforating service, but the industry has defined a series of standardised test procedures which will allow a comparative measure to be made of the charges on offer. The test procedures and guidelines are contained within the API Recommended Practise No 43 5th edition. To characterise the performance of perforation charges, a number of different tests are proposed. Section I details the testing to be conducted to assess the physical performance of perforating charges in terms of the perforation dimensions under preset firing conditions. Section II of API RP 43 deals with the assessment of the impact of confining pressure on the physical dimensions of perforations created in a sandstone sample confined by a simulated over burden pressure. Section 3 and 4 deals with the effects of temperature and the flow capacity of perforations respectively.

The section I test prescribes the firing of a perforating gun into a casing which has been cemented with concrete into a drum. The gun can be positioned to provide the degree of eccentricity to be expected within the casing under downhole conditions and will contain several charges which will be detonated simultaneously to simulate downhole firing. Normally the gun will be arranged to provide the shot phasings and clearance expected to be used downhole. The test requires that the concrete must have been cured for a minimum of 28 days prior to use and possess a minimum tensile strength of 400 psi (which corresponds to a minimum compressive strength of 4000 psi).

After detonation of the gun, the casing and target will be examined and the following measurements made and reported:-

(1) The burr height on the casing

(2) Average diameter of the perforation

(3) Length of the perforation.

In addition, the gun clearance for all shots and gun positioning must be recorded.

The Section I test in no way attempts to compare the flow effectiveness and takes no consideration of the crushed zone characteristics. However it does give a guide to comparing perforation charge capabilities albeit on a comparative basis only, since no attempt is made to assess the performance in specific lithologies.

In the section 2 test a 4" diameter Berea sandstone core is perforated.

2.2 Significance and Validity of API RP No 43 5th Edition

It must be stressed that the API RP 43 tests are principally of comparative value only and provide little direct indication of downhole performance.

The section I test seeks merely to establish a comparative measure between the physical characteristics of perforation produced under constant conditions using a range of charges. Since no attempt is made to establish the performance in specific lithologies and using realistic in situ stresses the results in fact provide little indication of the real perforation characteristics which will be achieved in the reservoir. Since no method has yet been published to allow a prediction of performance under different compressive loads and with different lithologies, it is difficult to use the Section I tests to predict downhole performance.

The section 2 test allows the effect of over burden or confining stress to be evaluated. The data from this test can be extrapolated to penetration in any reservoir of known compressive strength using:-

$$\ln P_f = \ln P_t + 0.086\,(C_t - C_f)/1000$$

where

C_t = Compressive strength of test material, psi, e.g. Berea sandstone 6500 psi:

C_f = Formation rock compressive strength, psi.

P_t = Penertration measured in API RP 43 test, inches.

P_f = Penetration predicted for formation rock, inches.

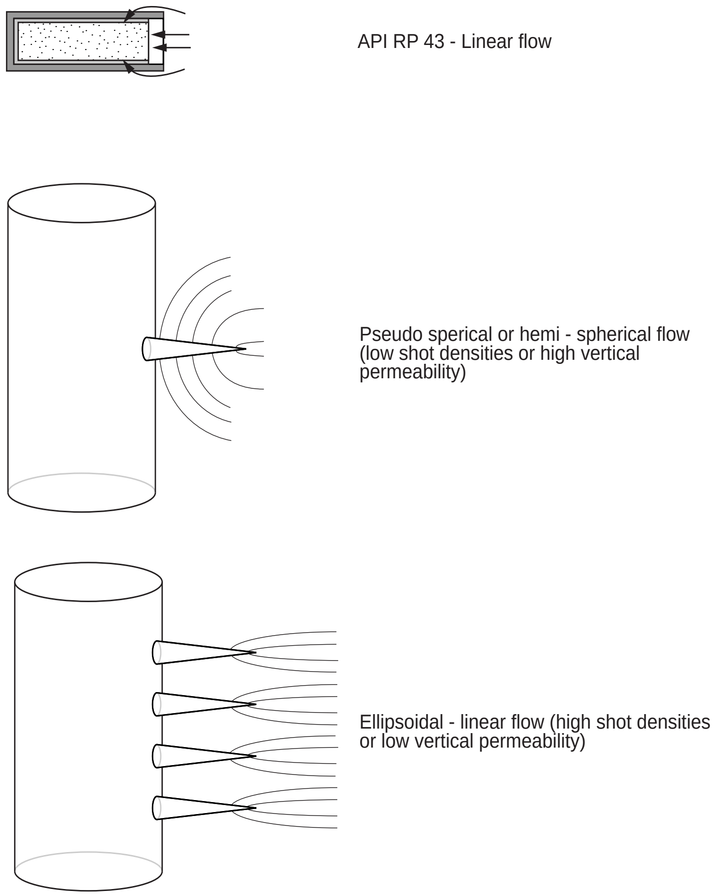


Figure 13
Flow profiles compared between single and multi shot tests

Similarly, the flow test Section 4 test is both simplistic and idealised and has the following limitations:

(1) The core material is specifically sandstone and the crushed zone properties obtained with this may be radically different both in terms of permeability and permanency than for, say, a chalk reservoir.

(2) The core is bounded by a steel canister and this allows about 1 $^1/_2$" of core surrounding the perforation tunnel. This confinement system may contain and restrict the diameter of the perforation thus perhaps extending its length. This may be a suitable test to simulate 4 shots/ft in line firing where a no flow boundary may occur at 1 $^1/_2$" radially from the centre line of the tunnel but may not simulate the case of lower shot densites or 90° and 180° firing.

(3) The fluid flow profile in the core is linear through the unperforated section and into the end of the tunnel. In reality the flow profile will vary from being near hemispherical in the case of 1 shot/ft, through ellipsoidal at intermediate shot densities 2-4 and perhaps approximately linear at the high shot density situations. This is depicted in Figure 13.

It is clear that there is no complete ability to extrapolate API RP 43 test data to predict real downhole performance in specific reservoirs. Further, the general validity of the specific tests to simulate real perforation flow and clean up characteristics is doubtful. Work has been conducted on various lithologies and also using cylindrical cores with a variable overburden pressure.

3 PERFORATING GUN SYSTEMS

Several key features classify perforating operations including:

(1) Whether the gun will be run on wireline or be conveyed on tubing or a drill string.

(2) Whether the pressure in the wellbore at the time of perforating will be less than reservoir pressure, i.e. an ***underbalanced*** pressure condition, or be greater than reservoir pressure, i.e. an ***overbalanced*** condition.

(3) The extent to which the gun, the charges or charge carrier will be retrieved from the wellbore after perforating.

(4) Whether perforating will be conducted prior to, or after, mechanical completion of the well.

The majority of wells are perforated using wireline conveyed guns. However, there are two alternative approaches:

(1) The guns can be lowered into the cased wellbore prior to installation of the production tubing. In such cases, the guns are referred to as casing guns and both during and after the operation it is necessary to maintain a wellbore pressure which exceeds the reservoir pressure unless surface pressure control equipment is being used. Thus the approach utilises overbalanced pressure conditions.

(2) Alternatively, after installing the completion tubing, a gun can be selected to be run down the inside of the tubing, out of the tailpipe and perforate the casing. The guns in this case are referred to as through tubing guns.

Alternatively, the perforating guns can be tubing conveyed either on the end of the completion string, coiled tubing, or at the end of a drill pipe test string which will be retrieved after well clean up prior to running the completion string.

The options are depicted in Figure 14.

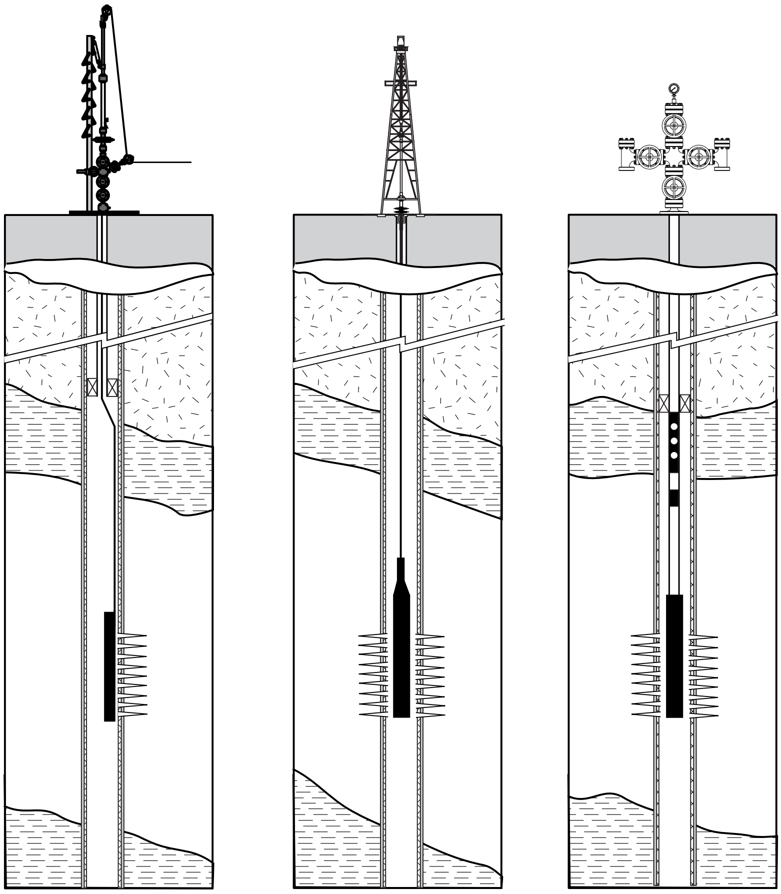


Figure 14
Optional techniques for perforating

Perforating guns also vary according to the extent to which they are expendable, and are classed as follows:

(a) Retrievable or hollow carrier guns are designed such that the individual charges are fitted to a carrying strip and then connected to a primer or detonating cord. The carrier strip with charges is then inserted into a steel carrier tube which is sealed prior to running downhole on wireline (Figure 15). The advantages and disadvantages of this type of perforating gun are listed in Table 1.

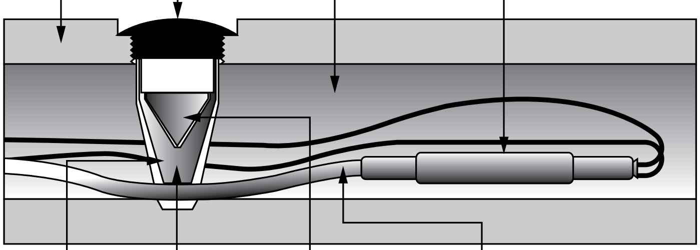


Figure 15
Schematic cross section of hollow carrier perforating gun

	Advantages	Disadvantages
Retrievable hollow carrier gun	Robust and less liable to be damaged during running in charges protected from: (a) well fluids (b) well pressure (c) well temperature Fast running speeds into the well bore. No debris	Gun length is limited by height availability for handling or lubricator size (normally 60' max). Weight of hollow carrier can be significant. Large intervals to perforated will require multiple runs.
Fully expendable guns	Flexible and thus can be run in longer lengths (up to 200 ft per run). Most economical in terms of both gun cost and time. required.	Debris left in wellbore. Components immersed in well fluids. Pressure and temperature may limit the use of certain charges. The gun is not rigid nor durable and maylimit running in speeds or tension to be pulled if gun becomes stuck.
Semi - expandable	Debris limited to crushed charge cases. More economical than hollow carrier guns.	Rigid carrier strip constrains gun length as for hollow carrier guns. Charges may suffer pressure and temperature limitations since they are immersed in well fluids.

Table 1
Comparison of retrievable, expendable and semi expendable perforating guns

(b) Expendable perforating guns are designed such that the gun will self-destruct on detonation and thus only the connectors and depth correlation equipment will be retrieved from the well. Such guns comprise a number of charges which are essentially strung together, i.e. no rigid carrier strip or tube is used. The charges are also designed such that the charge case or container will fragment / disintegrate on detonation. The material used for fabrication of the charge case must be friable, e.g. ceramic or aluminium, but must offer a reasonable degree of robustness to protect the charges during handling operations.

Since the assembled gun is not rigid, the length of gun which can be used is not limited by height availability or lubricator size. Table 1 lists some of the important advantages and limitations of these guns.

(c) Semi expendable perforating guns are designed to offer the advantages of gun durability and robustness which exist with the hollow carrier and the charge disintegration of fully expendable guns. The guns are designed such that the charges which are expendable are mounted on a carrier strip for running into the wellbore.

3.1 Wireline Conveyed Casing Guns

These guns are largely constrained by two factors:

(1) The gun diameter must be less than the casing inside diameter. This allows a large diameter gun to be used and hence large charges.

(2) The length of gun is defined by either the weight which can safely be suspended by the wireline or by the length of lubricator into which the gun will be retrieved after perforating in underbalanced conditions.

Thus, guns are normally in the range of 3 $^{3}/_{8}$" to 5" diameter and have the following advantages:

(1) The gun diameter can allow for the use of fairly large explosive loads in the shaped charges.

(2) The gun diameter which can be run into the well must allow for a minimum clearance of $^{1}/_{2}$". However if the gun size is fairly large there will be reduced standoff or clearance for the charges, and such guns can take full advantage of 90° shot phasing to provide improved flow performance.

Casing guns are available in all 3 classifications of retrievability as shown in Figure 16. In the majority of operations where the interval to be perforated can be accomplished with a limited number of guns, then a retrievable hollow carrier gun or a semi expendable gun will be used. These guns can be used with a pressure control system at surface which would comprise a lubricator and wireline BOP system mounted on the Xmas tree.

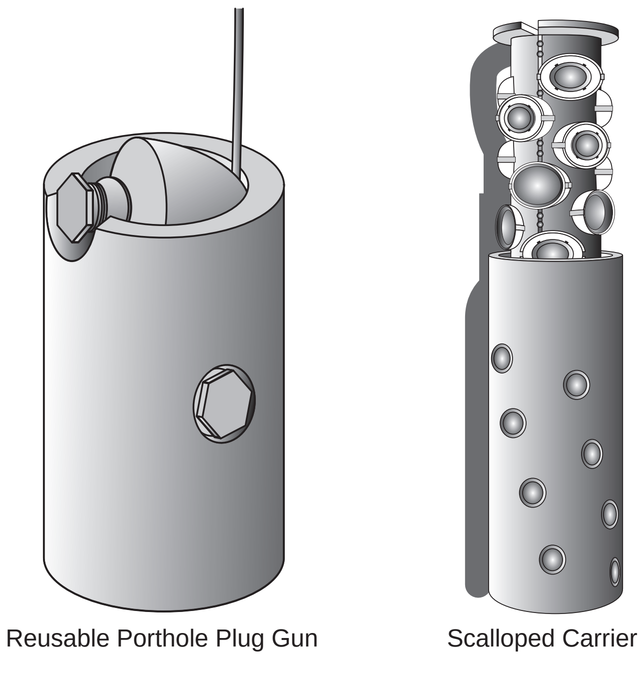


Figure 16 Examples of casing perforating guns

The principal application of the fully expendable guns would be in the perforation of long intervals where, because of their flexibility, longer lengths can be introduced into the wellbore. Thus, it may be feasible to create all the perforations simultaneously.

In general terms, the penetration obtained with casing guns is high, due to the larger charge sizes which can be used in combination with the reduced gun standoff. However, the larger the gun size, the higher is the entrance hole size and the CFE obtained. The 5" "big hole" guns are intended primarily for perforating to reduce the possibility of sand production or prior to the installation of a gravel pack. The principal advantage of these guns is that the entrance hole is substantially larger than with guns with a diameter in the range 3 $^{1}/_{8}$" - 4".

Casing guns can normally provide perforations which are larger in diameter and deeper than those obtained with through tubing wireline guns. Their size provides an opportunity to use not only larger explosive charges but also higher shot densities.

The main disadvantage is that this type of gun is most frequently used prior to mechanical completion and since it will thus provide communication between the formation and the wellbore it is necessary to either isolate the perforations or retain a fluid in the wellbore which exerts a bottom hole pressure greater than the reservoir's pressure. This can be obtained by any of the following:

(1) Use a drilling mud in the wellbore which, because of its pressure, will leak into and plug the perforations (see Figure 17). This is not recommended.

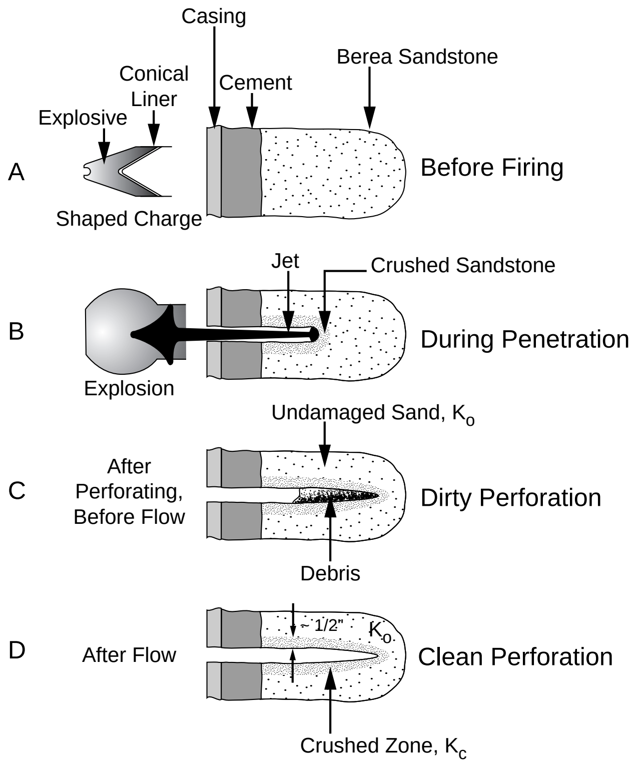


Figure 17
Perforation plugging prior to flow caused by solids invasion from the fluid in the wellbore

(2) Use a clear completion fluid which will require effective fluid loss control using either a high viscosity or a granular bridging material if losses are not to become excessive.

(3) Set a high viscosity plug across the perforations, with a kill fluid above it. It is imperative that after perforating in this way the bottom hole pressure is maintained throughout the period of installing the completion string until the well can be brought into production.

The use of such guns therefore is a compromise between better charge performance and ultimate reservoir performance. Compared with through tubing guns, casing guns offer substantially better charge performance as is evident from Fig 18. However, the final productivity may only be comparable to, or in a large number of cases inferior to, that obtained with through tubing guns.

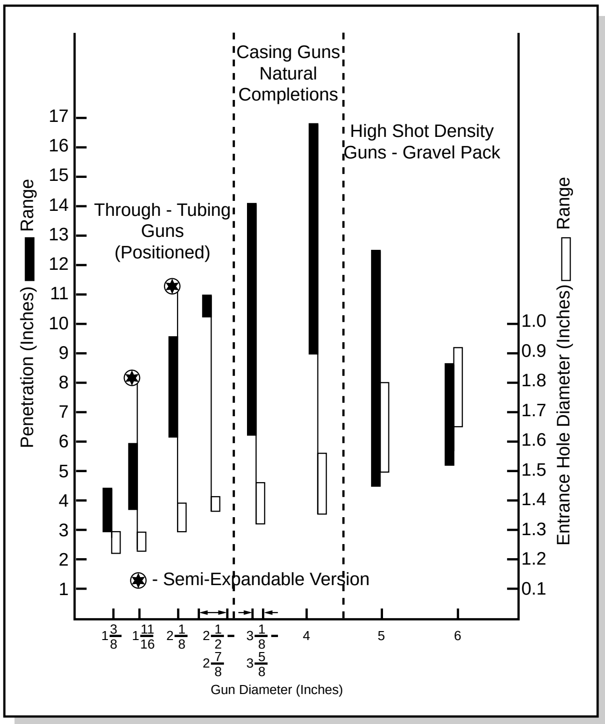


Figure 18
Comparison of API RP 43 section I performance of hollow guns

3.2 Wireline Conveyed Through Tubing Guns

Wireline conveyed through tubing guns will obviously be constrained in diameter, and consequently charge size, by the smallest inside diameter in the production tubing string. In low flowrate wells where very small tubing sizes are necessary, this technique will thus not be feasible and in such cases wireline conveyed casing guns are used. However, through tubing guns are available in sizes down to 1 $^3/_8$".

Since the gun can be run in after the well is mechanically complete and the equipment pressure tested, the well can be perforated under drawdown to simulate the reverse pressure firing mode. In such cases the drawdown can be controlled by a combination of fluid density and surface pressure.

Through tubing guns are available in a range of diameters from 1 $^3/_8$" to 3 $^1/_2$", as retrievable, semi-expendable and fully expendable perforating guns (Figure 19). Most commonly, however, it is the retrievable and semi-expendable guns which are used. In general terms, the through tubing guns give reasonable performance, with the semi-expendable charges giving slightly better performance for comparable charge size in terms of penetration and flow efficiency. In comparison with casing gun charges, the through tubing gun charges offer substantially reduced penetration and in terms of flow efficiency they at least match the performance of casing guns.

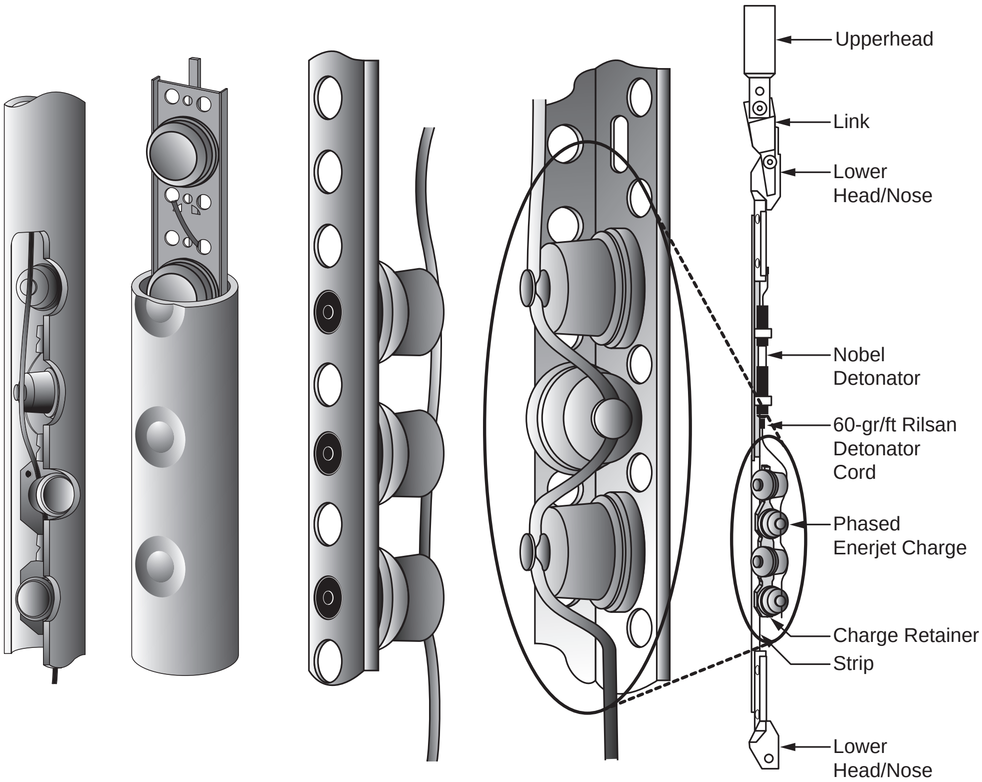


Figure 19
Wireline conveyed through tubing perforating guns

The real benefit of through tubing guns is their ability to perforate under drawdown conditions. The use of a drawdown prevents fluid inflow from the wellbore into the perforation and also serves to flush out material lodged within the perforation tunnel or surrounding matrix. It must be stressed however that due to the restriction on gun length caused by gun retrieval only the first gun is detonated in under balance. In general terms to remove damage from the tunnel itself, the higher the differential pressure the more effective will be the clean up process. However the use of excessive drawdowns can lead to:

(1) Collapse of the formation around the perforation tunnel.

(2) Mobilisation of fine particulates within the formation which can cause destabilisation of the formation or blockage of the pore space.

In most cases the drawdown must be held within reasonable limits although for the lower permeability rocks higher drawdowns can be used because:

(1) Higher drawdown will be required to create sufficiently high flowrates.

(2) If the reduced rock permeability is due to grain size and not just to pore space infill, then the compressive strength of the rock will be higher.

For oil wells the drawdown should be in the range of 250-1000 psi for productive wells; and for low permeability wells, say, 1000 psi for wells of a permeability of 100 md, and up to 2000 psi for lower permeability reservoirs. Gas well drawdowns in excess of 1000 psi are typical and can be increased up to 5000 psi in reservoirs with a permeability of 1 md or less.

However, the exact drawdown has to be matched to specific well conditions.

Through tubing perforating is a most widely applied method and offers a reasonable compromise between charge performance, well productivity and safety.

3.3 Tubing Conveyed Perforating Guns

As the name implies, tubing conveyed perforating, or TCP, involves the assembly of a perforating gun on the end of drill pipe string, production tubing or coiled tubing and its lowering and positioning in the wellbore prior to detonation. The technique has increased rapidly in both application and development during the 1970s and is now widely employed. After detonation, the gun can either be pulled from the well or detached to drop into the wellbore sump below the perforated interval.

3.3.1 Deployment Options

Tubing conveyed perforating can either be employed by:

(1) Running the guns with a conventional drill stem test assembly as shown in Figure 20a. After clean up, the well would have to be killed prior to retrieving the test string, normally with the spent gun. Subsequently, the well would be completed if required.

(2) The gun could be run attached to the base of the completion string tailpipe below the packer. The string would be run into the hole, landed off, the packer set and the gun detonated under drawdown. Normally, the guns would be detached and dropped into the sump (see figure 20b).

(3) Running and retrieving the gun on coiled tubing using a CT deployment system.

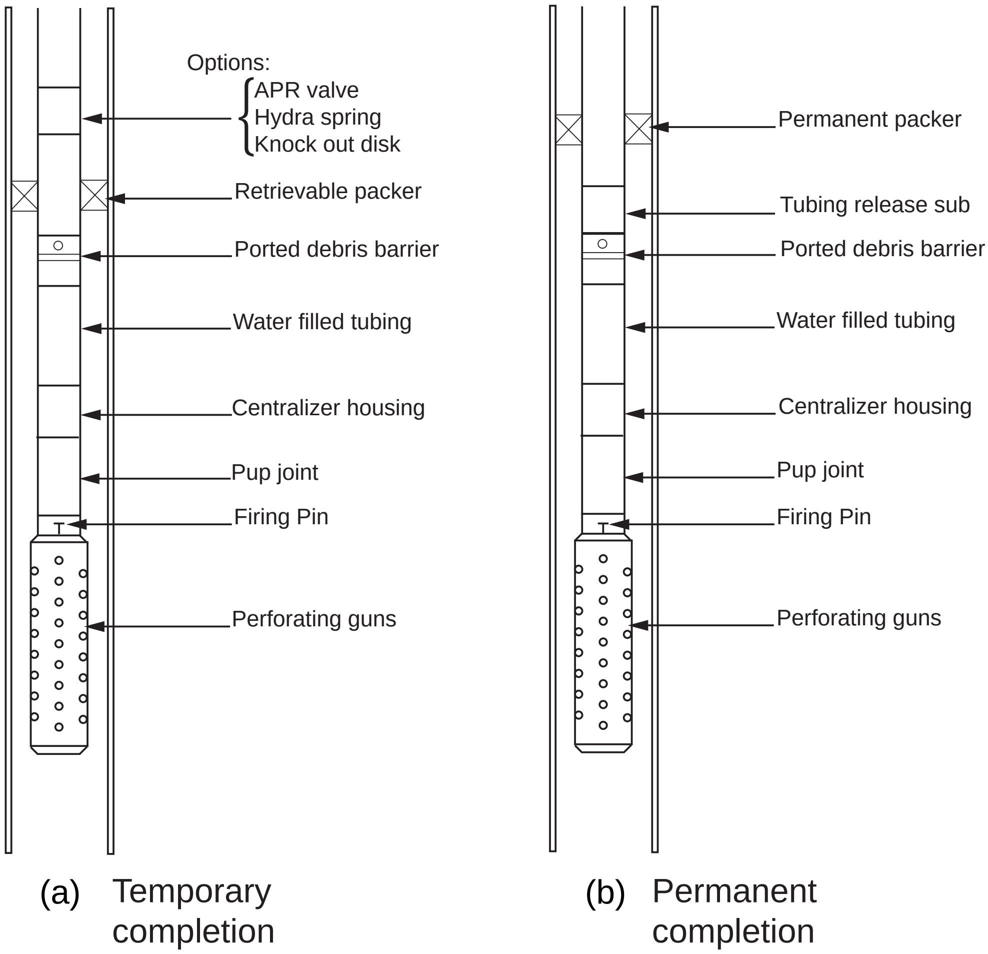


Figure 20
Common configuration for TCP system

3.3.2 Firing Options

When the gun is in position, it can be detonated by one of a number of optional techniques:

(1) Mechanical firing

A bar or go-devil can be dropped down the tubing onto a plunger which contacts a blasting cap on top of the gun. An inferior method is to incorporate the blasting cap on the bar which is dropped downhole. This method can be unreliable if debris is allowed to accumulate on top of the firing head. This potential problem can be alleviated by running a ported debris barrier which will allow circulation above the firing head prior to detonation. Apart from surface pressure, there is no reliable indication of detonation and this can lead to uncertainties regarding safety if the string has to be pulled.

(2) Hydromechanical

In this technique, the annulus can be pressured up and the pressure routed through a bypass valve above the packer, onto a series of shear pins on the firing head. Once a differential pressure is exerted sufficient to shear the pins, the firing pin is driven down against the detonator. This technique would be more reliable than the mechanical method, especially in deviated wellbores.

(3) Wireline firing

In this system, a special wet connect is run on wireline after the guns are positioned. This wet connect attaches to the firing head which can then be fired by passing an electrical current down the cable from surface. The main advantage of this technique is that, besides surface pressure being created on successful firing, there are also electrical indications at the surface.

3.3.3 TCP Gun Disposal

After detonation the gun can be dropped. However, if it is decided to flow the well either before detaching the gun, or if it is intended to retrieve the gun, a vent assembly or perforated joint must be provided below the packer where fluid can enter the flow string.

3.3.4 Advantages / Disadvantages of TCP

A major advantage of TCP is that as with using casing guns, the gun size and, accordingly, that density and charge size can be quite large. Given the size of the guns, it would be expected that the charges would offer deep penetration with large entrance hole size and good flow efficiency. The principal advantages of TCP are that it can offer the ability to use large charges with high shot density (up to 16 shots/ft) and perforate under substantial drawdown if required. It therefore combines some of the advantages of casing and through tubing guns.

The advantages of tubing conveyed guns are:

(1) The ability to use high shot densities and to create large entrance hole sizes can lead to reduced hydraulic erosion in the formation around the perforations. This allows higher flowrates to be realised without formation breakdown.

(2) The perforating operation can be completed in one run even for long intervals. Intervals in excess of 1000 m have been shot in one run with TCP.

(3) Unlike wireline operations, even if the interval is fairly large, the ability to shoot the interval with one gun means that all the perforations are created simultaneously, which benefits well clean up and productivity.

(4) As with the through tubing techniques the well is not perforated until the well is completed and it is safe to allow well fluids to enter the wellbore.

(5) With wireline conveyed guns, whilst perforating under drawdown, there is a danger that the guns will be damaged or blown up the wellbore if too high a pressure drawdown is used. With TCP, the durability of the system allows high differential pressures, e.g. >2500 psi, to be used.

(6) If the hydromechanical firing option is used the technique is feasible, even in highly deviated wells, as there is no dependence on wireline nor on a go devil detonation system.

(7) If either the mechanical or hydromechanical firing system is used there is no necessity for radio silence.

The disadvantages of TCP are:

(1) If a misfire occurs, then gun retrieval will require a round trip which is both time consuming and costly. There is also a safety concern as to why the gun has not detonated. Detonation whilst the string is being retrieved, although rare, has occurred.

(2) If the gun is not detached but is to remain opposite the perforated interval, it will prevent production logging or through tubing wireline below the tailpipe.

(3) Since the running procedure for the guns is prolonged, the charges may be exposed to well temperatures for an extended period and this may lead to degradation.

(4) In general, the costs of TCP are higher than conventional wireline perforating. The cost differential will decrease as the length of interval to be perforated increases. Further, if the gun is to be dropped into the sump the cost of drilling the additional sump length must be considered.

(5) Surface observation of the degree to which the charges have fired is not possible unless the gun is retrieved.

4 OPERATIONAL CONSIDERATIONS

Exphasis has been placed in the previous sections upon the concepts of perforating and charge performance. In this section operational considerations will be discussed.

4.1 Surface Pressure Equipment

The majority of perforating operations are conducted under conditions of under balanced pressure. In the case of through tubing guns particularly, there will be a need to allow retrieval and removal of the gun from the well on which there will exist a THP after perforating. There will therefore be a need to assemble a lubricator and wireline BOP in much the same manner as for the conventional slick wireline. Normally both a hydraulically actuated and a manual BOP valve are located at the base of the lubricator. In addition, since the gun will be lowered on a braided electrical conductor cable, the sealing of pressure as the cable leaves the lubricator will be a serious problem. In conventional slick line, a stuffing box can be reasonably effective on a single strand line. However, when perforating, sealing is provided by grease injection through a port into a flow-tube through which the cable passes.

4.2 Depth Correlation

A reservoir can either be blanket perforated in which most of the reservoir is perforated with little selectivity, or alternatively selectively perforated over a reduced interval(s). The latter case is perhaps more prevalent, and it will therefore be necessary to ensure that the perforating guns be located at the required depth prior to firing. A number of wireline techniques are available for depth correlation against previous wireline logs:-

(1) Gamma Ray Log GR
A gamma ray log can measure the shaliness of a formation even behind a casing. Since the log is widely run, a log will normally be available at the time of perforation for correlation. Thus a gamma ray log is frequently incorporated above the perforating gun and used to depth correlate against a previous gamma-ray log.

(2) Casing Collar Locator CCL
A casing collar locator log monitors the location of casing couplings in that it responds ultrasonically to the wall thickness of steel. This log is normally run with a cement bond log CBL or cement evaluation tool after casing cementation. A CCL can be run above the perforating gun and used to monitor casing collar location for depth correlation against a previous log. However, since most casing joints are similar in length, confusion as to the exact depth can occur. This can be prevented by installing a smaller pup joint (10' or 20') in the original casing string, located in the proximity of the top of the reservoir. This joint will act as a marker and ease exact depth correlation.

(3) Nuclear Logs
It is possible to use nuclear logs such as the Compensated Nuclear Log CNL as these will respond to fluid saturation/porosity behind the casing. However, given that these logs utilise a nuclear source, they are less frequently used in conjunction with perforating guns.

In most cases a combination of CCL and GR is used and using these techniques it should be possible to depth correlate to with a minimum of 1-2 ft. of the required depth. In the case of TCP, a radioactive source is frequently used for depth correlation.

4.3 Safety Procedures

It is well recognised that explosives of any sort should be handled with extreme care. In most cases the charges themselves do not pose any real danger until they are assembled in the gun and the gun is armed.

For wireline conveyed guns where the guns will be detonated by an electrical current signal passed down the cable, there is real concern that the gun could be accidentally detonated by stray current. When using wireline guns there is a need to observe certain precautions aimed at eliminating sources of stray current. Some of the safety rules normally applied are as follows:-

(1) Radio silence to be observed on the rig and adjacent to the location.

(2) No welding.

(3) No crane operation.

(4) No high amperage lights in the drill floor vicinity.

(5) Shutdown temporarily cathodic protection system if working offshore.

The danger of stray current detonating the gun exists from the time the gun is armed until it has been run to a safe depth downhole, say a minimum of 500ft. below the sea bed. The shutdown safety procedure should also be observed in retrieving the gun until the gun has been checked to ensure that all the charges have fired.

In the case of TCP, the above concerns of stray current will also apply to those guns which use an electrical detonation system.

As an attentive safety shutdown system are available which will isolate the gun in the event of a stray detonation current source.

4.4 Gun Length/Perforated Interval

The length of gun which can be used in the case of retrievable or semi expendable guns is limited by the lubricator length and in the care of larger gun diameters, the tensile strength of the cable. Normally the gun will be between 15 - 40ft. If the required perforated interval is larger than this, then multiple trips with perforating guns will be necessary. In such cases

The lubricator provides the necessary well security. Perforating usually starts at the lowest interval in the zone or the interval with the lowest permeability and moves upwards on successive runs.

4.5 Perforating Multiple Zones

If, for example, 3 intervals each 10ft. in length are required to be perforated it is possible to make up a single gun which comprises 3 sections and can be detonated with a switch system.

If the zones are large, they will normally be perforated separately with individual guns.

4.6 Temperature Effects

Explosive charges can spontaneously detonate if exposed to high temperature. The RDX explosive will detonate at 340°F. Other explosives are available which are more stable at temperatures in excess of 500°F. However, the stability is also affected by the duration of exposure. In most wireline perforating operations, the gun will never warm up to bottom hole temperature because of the thermal lag and the fact that in a newly completed well, the completion fluid will perhaps not have had time to warm up. However, such benevolent effects cannot normally be relied upon and the explosive charge should be selected appropriate to the anticipated well temperature.

However, in the case of TCP, the deviation of exposure of the charges in increased and the possibility of spontaneous detonation potentially more dangerous.

4.7 Casing Damage

The present trend is to use large charges (largest diameter gun) with higher shot densities. However, the possibility of casing damage is increased in these situations. In general terms, casing damage will be influenced by:-

(1) Casing steel grade and consequent compressive strength.

(2) The quality of the cement sheath and the extent to which it provides radial support to the casing.

(3) The shot density, the number of shots in any plane will influence the stress on the casing during perforating.

The damage, if it occurs, is likely to be in the form of splits along the casing wall in the axial direction between perforations. This is clearly undesirable and should be avoided at all costs.

4.8 Gun Orientation

There are two particular situations where it is either desirable or essential to orientate the gun to perforate in a specific direction.

(1) In deviated wells, where the gun size is substantially smaller than the casing size, the degree of gun clearance due to the lack of centralisation will affect charge performance. In such cases it is frequently more beneficial to use 0° phasing and a magnetic positioning device to position the gun to fire in the low side of the hole where the gun is in contact with the casing. To further improve the effectiveness of this approach, a series of retrievable hollow carrier guns known as scallop guns were developed. The scallop gun as depicted in Figure 21, has part of the carrier wall machined opposite the charge to reduce the wall thickness of the steel carrier and provide optimum standoff. A further refinement is the hyperdome scallop which is designed to reduce the energy of the jet consumed in perforating through the carrier.

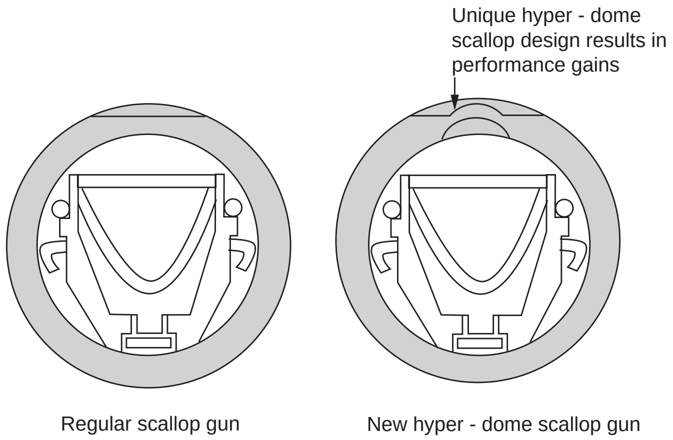


Figure 21 Scallop and hyperdome scalop guns

(2) If it is decided to run through tubing guns to perforate a dual or triple completion, there will be a requirement to orientate the gun whilst perforating the upper zone to avoid perforating the longer strings which will produce the lower zones. In such cases a radioactive isotope can be installed in the long string and the gun lowered through the short string with an orientation tool.

4.9 Charge Quality

An investigation by King et al has attempted to verify the extent to which charges live up to the expectations indicated by their quoted performance in the API RP.43 tests. It is clear that whilst some of the charges did in fact meet the quoted performance, a large number gave inferior performance. A large number of factors could influence this, including the age of the charges and the conditions under which they have been stored.

EXERCISE 1.

Jet Perforator Penetration as a Function of Compressive Strength

To convert from test data for perforation penetration obtained for API RP 43 we can use

Ln Pf = Ln Pt + 0.086 x (Ct - Cf) / 1000

Where:

Pf = Expected penetration in formation with a compressive strength of Cf psi
Pt = Test perforation based on Ct = 6500 psi

Two gun systems are being assessed for deployment for perforating:

1. 2 $^{1}/_{8}$" scallop through tubing (T.T.) gun giving 12" penetration in Berea sst.

2. 4" wireline (W/L) conveyed casing gun, giving 17" penertration.

Compare the guns for the following scenario:

1. Both guns for use with a low compressive strength chalk reservoir with Cf of 4000 psi.

2. Both guns for use with a deep high compressive strength rock with compressibilities of 12000 and 18000 psi respectively.

Solution: Jet Perforator Penetration / Function of Compressive Strength.

From the formula given:

Compressive Strength psi	Penetration Depth In.	
	Through - tubing 12" Berea pen.	Casing gun 17" Berea pen.
4,000	14.88	21.08
12,000	7.48	10.59
18,000	4.46	6.32

Note the substantial reduction in penetration as a function of high compressive strength.

Benefit of casing gun is substantially reduced at higher compressive strength.

Completion Installation Practices, Procedures and Programming 9

CONTENTS

LEARNING OBJECTIVES:

In this module a basic but logical step wise approach to the actual process of completing a well is covered.

Having worked through this chapter the student will be able to:

- Describe the intergration of the various stages of completing a well.
- List and flow chart a general procedure to run a completion string.
- Describe the requirements to pressure test and retain well control throughout the completion process.
- Define the need for full and accurate reporting and records to be kept.

INTRODUCTION

There are a multiplicity of installation practices and procedures and these are influenced primarily by:

(1) the integration of the perforation operation and the mechanical completion of the wellbore.

(2) the particular completion string design and string components utilised.

In general terms, the process is one of taking a well which has been penetrated through the production or injection formation, with or without production casing, and converting it mechanically such that the well will be able to produce oil or gas to surface safely and at an optimum economic rate.

The integration of the various completion stages is shown in Fig 1. Clearly there are two options with respect to perforating, both of which can utilise wireline or tubing conveyed guns:

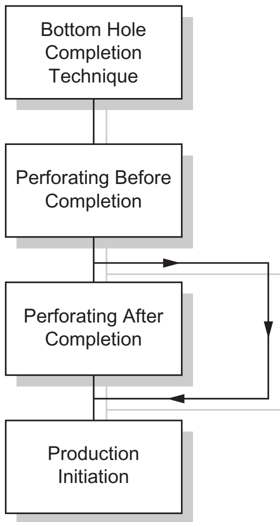


Figure 1

(1) Perforate before running tubing, whereby the hydrostatics pressure in the wellbore must continue to overbalance reservoir pressure.

(2) Perforate after installation of the tubing, whereby all or part of the interval can be perforated under drawdown conditions.

1 OPERATIONAL CONSTRAINTS AND CONSIDERATIONS

On the assumption that the status of the well prior to the start of the completion operation is that the pay zone has been drilled through and that the various casing strings have been installed, there are a number of conditions which must be maintained throughout the completion operation.

1.1 Reservoir Inflow Must be Prevented

In the case of wells perforated prior to mechanical completion this is accomplished usually by maintaining a hydraulic overbalance i.e. the borehole hydrostatic pressure must exceed the reservoir pressure thus fluid column height and wellbore fluid density must be maintained. The correct level of overbalance differential pressure will vary but it must be consistent with:

(1) minimising leak off into the reservoir. Theoretically, fluid will leak off into the reservoir until the bottom hole hydraulic pressure in the wellbore approaches reservoir pressure i.e. the height of the fluid in the production casing-tubing annulus will decline.

(2) the provision of adequate overbalance to allow for the thermal effects of long term placement of the fluid in the wellbore i.e. density reduction in the case of completion brines and degradation of polymers in the case of fluids which suspend weighting material.

(3) minimising formation damage generated by leak off in the near wellbore area.

For wells which are to be perforated after mechanical completion, the concerns are primarily to ensure that the cementation of the production casing/liner provides effective hydraulic isolation between the wellbore and the formation and that this capability is not detrimentally affected by the differential hydraulic condition between the wellbore and the reservoir.

1.2 Prevention of Mechanical Damage to the Wellbore, Casings or Wellhead

The susceptibility to damage of the permanent wellbore equipment and formation will depend on the particular drilling and completion programme.

(a) Wellbore damage

The need to protect the formation against formation damage has been reviewed above. However, in the case of barefoot or open hole completions, maintaining borehole stability is essential. This will be achieved in most cases by:

- maintaining adequate hydraulic pressure in the borehole to radially support the formation.

- using a borehole fluid which will provide minimum swelling/hydration of formation clays.

(b) Casing/liner damage

Two types of damage can be affected namely:

- hydraulic

- mechanical

Hydraulic damage can occur as a result of collapse or burst conditions. Casing and tubing is normally designed to withstand collapse under simulated evacuation conditions and accordingly this should not occur provided the correct design conditions have been assumed. However, excessive underbalance pressure conditions between the wellbore and the reservoir should be avoided as there could be a different radial contraction response between the formation, cement sheath and casing. This could result in damage to the cement bonding. Damage due to burst is less likely and could only occur if:

(1) the casing is tested with too high an internal pressure - refer to tubing tables

(2) the annulus is closed off at surface and rapid hydraulic failure occurs when testing tubing with a high internal pressure.

Mechanical damage will occur as a result of contact between the inside wall of the casing and the tubing being run in. Contact is impossible to prevent totally, but in most cases the damage is minimal and is more likely to affect the tubing rather that the casing.

(c) Wellhead damage

Damage in the wellhead region particularly to hang off or landing areas, is of greater significance given the configuration of the landing area, the constriction offered by the shoulder and reduced clearance. Damage to a seal bore area can impair the sealing capability and hence the pressure isolation requirements. In most land or platform completions the proximity to the wellbore allows greater control in the process of running tubing through the wellhead. In subsea completions the remoteness introduces a greater potential for damage.

1.3 Safe and Effective Installation of the Completion Tubing(s)

The completion string and its components must be installed in the wellbore at the correct depth and in good operational order i.e.

(1) Specific items of equipment should be positioned at or near the desired setting depth e.g. SSSV, packer etc.

(2) Mechanically functioning equipment must be operational e.g. seal assemblies, sliding sleeves etc.

(3) The complete string must be able to withstand the test (and hence operating) pressure.

(4) The packer must be able to withstand, without leakage, an operating differential pressure.

2. WELLBORE COMPLETION

Subsequent to drilling through the pay zone in the case of an open hole completion or setting/cementing the production casing for a cased hole completion, the following preparations are required prior to running tubing.

2.1 Open Hole Completion

The wellbore preparation must ensure that:

(1) the borehole is free from drilled cuttings

(2) the borehole is stable and not subject to continuous caving/collapse

(3) the borehole contains the required fluid to allow effective completion of the well.

(4) to ensure no obstructions exist internally within the casing.

(5) the internal walls of the casing are clean across the proposed packer setting interval.

2.2 Cased Hole Completion

In this case the preparation must ensure that:

(1) a downhole logging suite is available to allow depth correlation between formation intervals and location of casing couplings.

(2) to identify the location of the top of the cement shoetrack and dress the TOC as necessary.

(3) to ensure no obstructions exist internally within the casing.

(4) the internal walls of the casing are clean across the proposed packer setting interval.

(5) the wellbore contains the required completion fluid in good condition.

The wellbore preparation can be conducted by running a drillstring with a scraper if required, to clean the inside of the liner at the packer setting location. The assembly will allow tagging of TD, circulation of the hole, internal cleaning of the casing across the packer setting interval and displacement of the well to the completion fluid. The sequence of operations is shown in Figure 2.

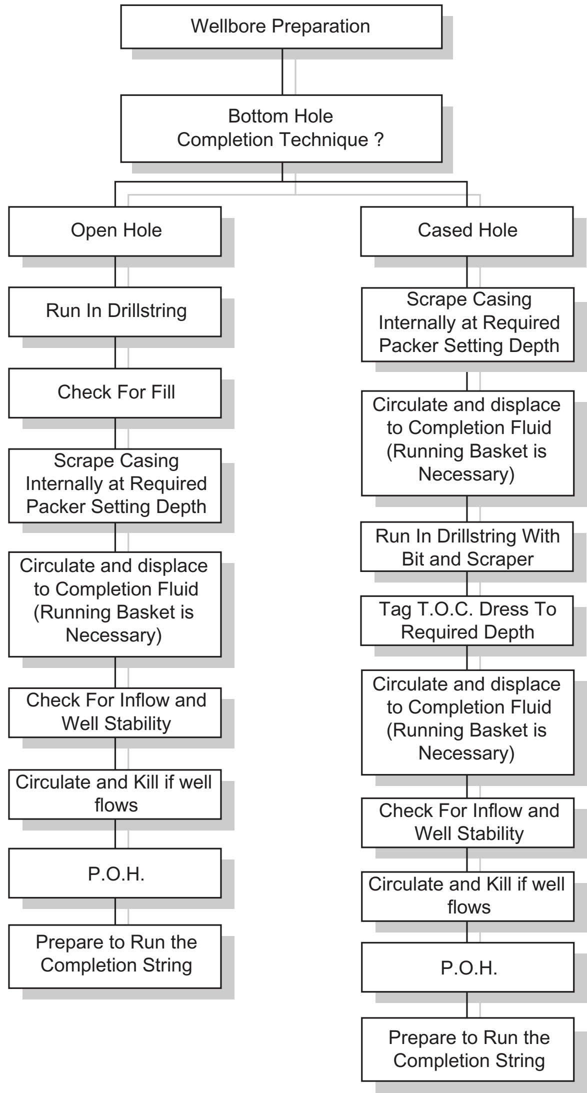


Figure 2
Wellbore preparation

Throughout this phase, the wellbore will be continuously checked for inflow as a sign of insufficient hydraulic overbalance or ineffective cementation of the production/ casing liner. In the case of inflow being identified, the well will be hydraulically killed by circulation with the additional security of the BOP being available until the correct remedial measures can be identified and implemented.

3. COMPLETION STRING RUNNING PROCEDURES

The actual running procedure for the completion string will depend on the completion design. The installation sequence is however devised logically to allow for the equipment to be checked as to its operational and pressure integrity. At all appropriate stages of the installation, equipment should be tested sequentially e.g. whilst running tubing it would be preferable to conduct pressure tests at regular intervals rather than rely on one final pressure test after the tubing is installed.

Whilst the completion procedure will vary with each specific completion design, it is possible to outline an overall strategy for a well completion. Such a strategy is depicted schematically in Fig 3.

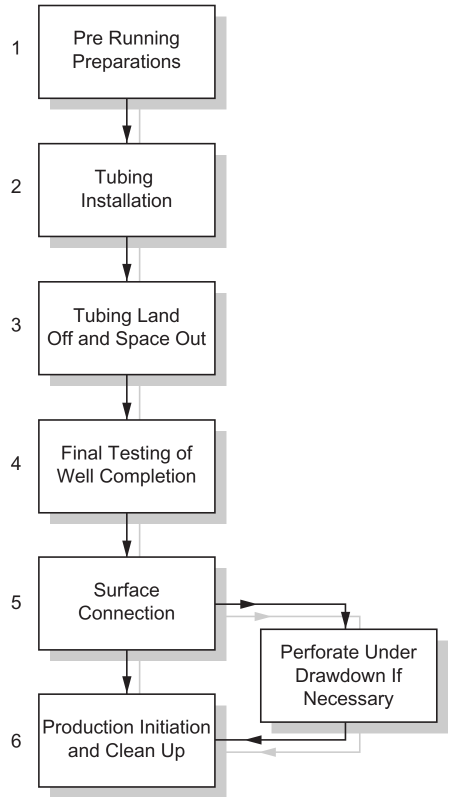


Figure 3
Overall strategy for completion installation

The installation of the completion is an integrated series of operations which by necessity must verify the operational capability of the tubing and all completion components. The further into the procedure the operation moves, the more significant is the potential for equipment failure to necessitate:

(1) a problem with well safety/security.

(2) inoperability of equipment.

(3) time consuming and expensive remedial or workover measures.

The method chosen for completion installation and its subsequent execution are the most crucial factors influencing effective completion performance.

3.1 Pre-running Preparation - Phase 1 (Fig 4)

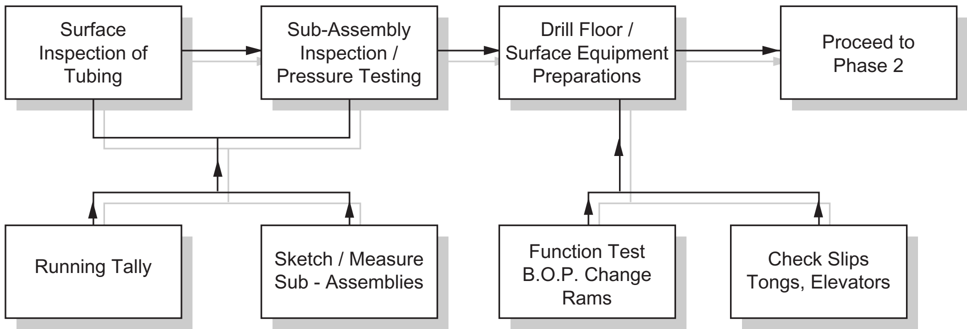


Figure 4
Preparations prior to running the completion

(a) Completion equipment
A completion string comprises a large number of joints of production/injection tubing, frequently of premium threads and high performance steel/alloy plus a selection of critical functional components. For the completion to achieve its operational performance, all equipment must function effectively.

The tubing will normally be supplied to the rig having been cleaned internally and externally, the threads having been inspected and protectors installed. Each tubing joint should undergo the following at the rig site:

(1) The made up length of each joint should be measured and numbered.

(2) Each joint should be drifted.

(3) The threads on each joint should be cleaned and inspected.

Tubing components will normally be transported to the rig site as a series of made up sub-assemblies. These assemblies, in view of their critical function, will have been made up to specification and thoroughly tested prior to shipment.

Each sub-assembly will be inspected, measured and drifted. It is good practice for a dimensional sketch to be made for subsequent reference and inclusion with the final status reports for the well.

(b) Running equipment
The make up of the completion string will require the use of specialist equipment:

(1) Tubing slips, optimally having a more gradual taper than conventional drillpipe slips and hence less likely to damage the outside wall of the production tubing.

(2) Tubing elevators, because of the need to minimise damage to the tubing and suspend tubing with little or no upset compared to drillpipe.

(3) Power tongs to ensure that torque is more evenly and correctly applied in making up the threaded couplings.

All the tubing running equipment should be installed and checked to ensure that it functions satisfactorily. Most importantly, particularly in the case of a well perforated prior to mechanical completion, the ability to isolate well inflow will depend on the blowout preventer package. It is therefore important that the pipe rams are changed to match the size of tubing(s) which will be run and that the stack is ***function tested***.

Lastly two important steps should be undertaken:

(1) A meeting should be organised to brief the drilling and completion staff as well as the specialist contract personnel.

(2) A diary of events should be initiated to record progress in the completion operation - this may be a most important diagnostic tool.

3.2 Tubing Installation

This phase of the completion operation depends largely on the conceptual design of the completion string as depicted in Fig 5. The principal parameters are:

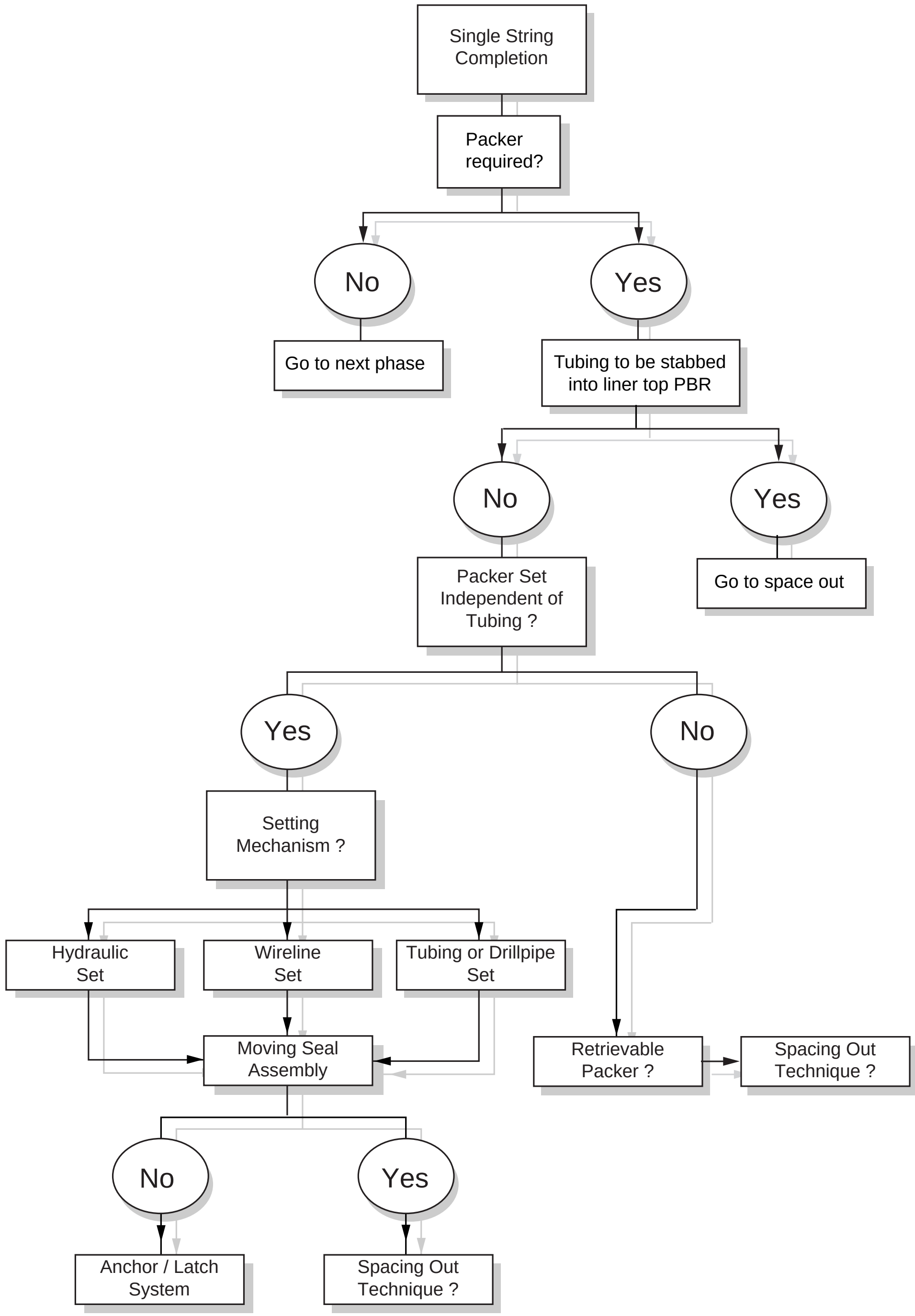


Figure 5
Possible tubing - tacker interactions for a single string completion.

(1) whether the packer is set with, or independently from, the tubing string

(2) whether a moving seal assembly is to be installed to accommodate tubing movement and hence relieve stress, and if so the manner of space out or seal positioning.

Clearly, the prior installation of the packer with or without a tailpipe, will offer benefits in terms of reservoir isolation in a workover situation. However, the detrimental effect is to impose another constraint on the running procedure.

Similarly, the incorporation into the design of a seal assembly is intended to improve the performance of the tubing string by increasing its ability to withstand stresses, but this will require positioning of the assembly at a specific location in the well.

The generalised procedure for tubing installation is shown in Fig 6.

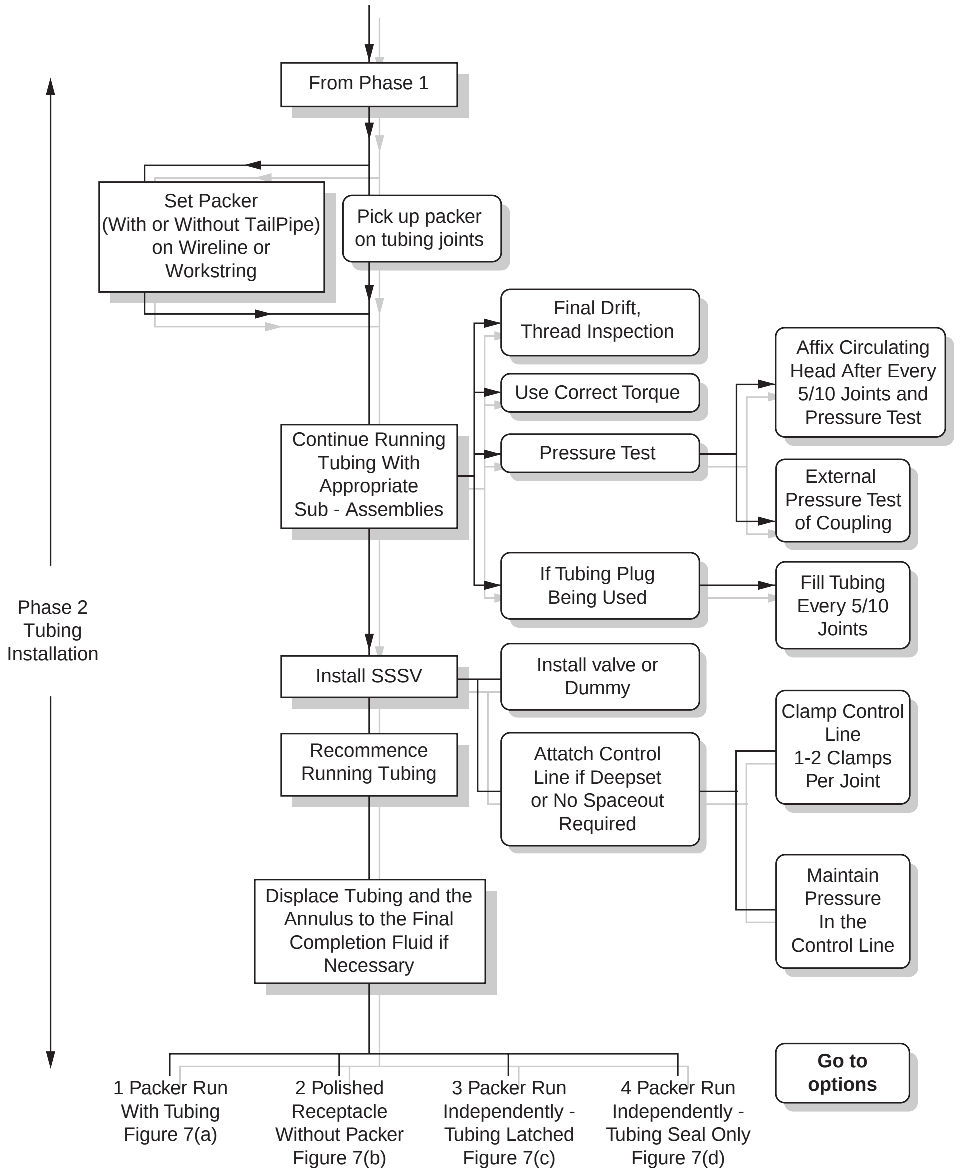


Figure 6
Phase 2 Tubing installation

The major task in this operation is the installation of the major length of the tubing string and associated sub-assemblies into the wellbore. Whilst running the tubing, the following actions must be pursued:

(1) Conduct final drifting and thread inspection of each joint prior to make up.

(2) Apply correct make up tongue.

(3) Apply external pressure test to each tubing coupling using Gator Hawk or preferably conduct internal pressure test. In the latter case, each joint must be checked but to do this for individual joints would substantially extend the completion time. However, the other extreme of only pressure testing when the maximum number of joints had been installed could be extremely risky since the likelihood of tubing joint failure will increase with the number of joints installed i.e. the depth of the completion.

The method of installing the subsurface safety valve SSSV will depend on the proposed setting depth for the valve and the completion configuration. Once the control line is attached to the valve, tubing manipulation should be minimised to prevent possible damage to the control line. If the tubing is to be connected to, or sealed within the base of an existing preset packer, whereby the packer must first be located, its position verified and the tubing retracted to allow space out, then it may be preferable not to attach the control line during the first run in of the tubing. After locating the packer, to allow adjustment of the length of tubing and inclusion of the tubing hanger, the tubing can then be pulled back to surface to expose the SSSV. Then the control line plus the required length of tubing plus the tubing hanger joint can be installed as the completion is lowered back into the well.

If the well is to be displaced to allow a particular packer fluid to fill the annulus between the tubing and the casing, then the well may be circulated at this point prior to stabbing the tubing into the packer.

The actual procedure for landing off the tubing and spacing out the string will depend on the specific completion configuration.

3.3 Tubing Land Off - Space Out Procedures - Phase 2

The exact procedure for landing off the tubing will depend upon whether the tubing is to be latched into the packer or attached by a seal assembly which allows for tubing movement. (Fig 6)

(a) Completion with no tubing movement provision

In this situation it will have been decided that the completion string will be suspended in the wellbore by the tubing hanger within the wellhead and at its bottom end will either be free as in a packerless completion or will be fixed at the packer. In the latter case, the tubing is fixed at the packer and at the hanger; hence there is either no anticipated tubing movement or the stresses generated by movement will be withstood by the completion without failure. However, having predicted the range of tubing stresses which could occur in a variety of operating scenarios, the stresses may be more satisfactorily accommodated if the string is set in compression or tension.

There are two methods of running a completion in this category

- packer run and set on the tubing
- packer run and set independently and then the tubing is stabbed into the packer bore

(1) Packer run and set on tubing
In this case, the packer will be lowered to the required setting depth with the tubing hanger located above the landing shoulder in the wellhead, Fig 7(a). Pressure testing of the tubing string against a plug should be conducted prior to setting the packer - see Fig 7(b). After setting the packer, the rest of the string would then be lowered into the well by slackening off the suspended weight until the hanger lands off with the string in compression. If it is required to land off the string in tension then the tension has to be applied after setting the packer. However, to accommodate tension setting, the completion has to be designed appropriately.

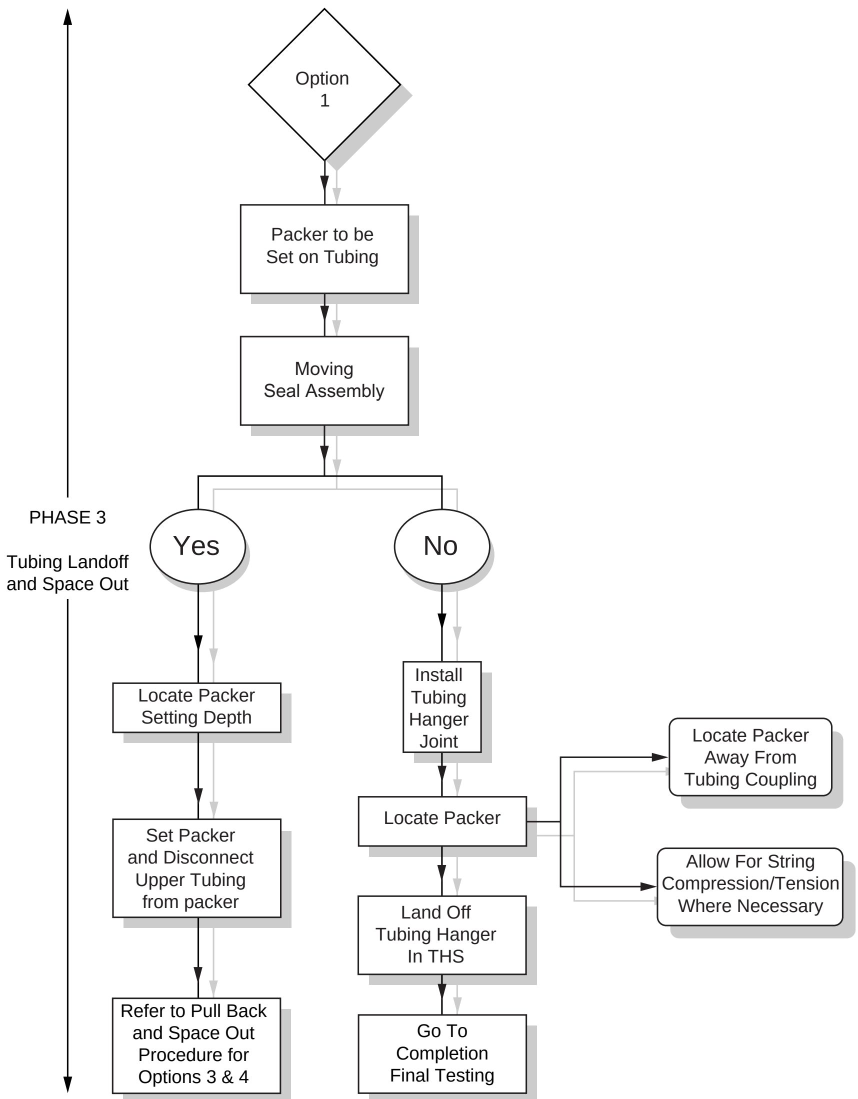


Figure 7(a)
Tubing land off / space out: packer run and set with tubing.

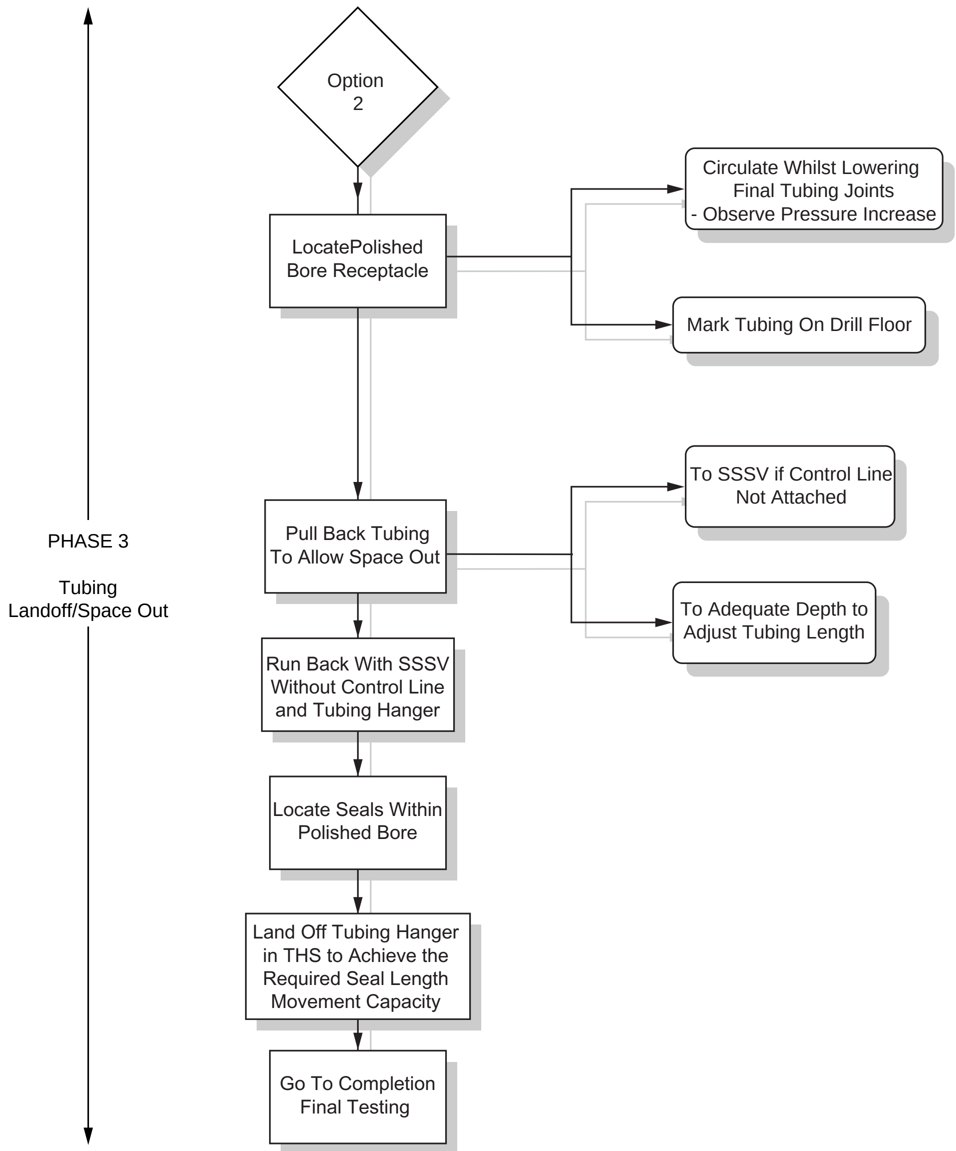


Figure 7(b)
Tubing land off / space out: completion with polished bore receptable

(2) Packer pre-installed and subsequent tubing stab in

In cases where the packer is set on wireline or with a work or drill string, the rest of the completion string can be run to either attach or latch into the packer bore or merely seal in the bore, Fig 7(a).

Where the packer is pre-installed and the string mechanically connected/latched into the packer, the string is lowered to locate the packer. Normally circulation down the string is started prior to final lowering to contact the packer (e.g. from 50-100ft above anticipated setting depth). A pressure kick signifies entry to the packer bore.

After marking and calculating the depth, the string can be pulled back, its length adjusted and the hanger joint installed so that on final lowering the string will first latch in the packer and will then subsequently land off in the wellhead upon continued lowering. The string at this stage would be set in tension or compression.

(b) Completion with tubing movement provision
In this case there are two major designs

- completion with annulus packer and tubing seal system

- completion with polished bore receptacle and tubing seal system.

(1) Annulus packer/tubing seal completion
In this type of completion, the first stage on running in the tubing is to locate the packer. If the completion system is one which will only seal in the packer bore such as a seal assembly or locator seal assembly, the tubing string can be pulled back so that the tubing length can be adjusted, the hanger installed and since this will be the final running operation, the SSSV control line installed if not already connected. The string can then be lowered into the well so that with the tubing hanger landed off, the seal assembly would be appropriately positioned through the packer bore to accommodate expansion or contraction.

If the tubing seal assembly will provide a mechanically fixed seal in the packer bore with a moving seal assembly higher up e.g. tubing seal receptacle (ELTSR). Then the lower component of the seal assembly must be stabbed into the previously located packer bore, and the upper section retracted to allow adjustment in the tubing length to set final seal positioning when, with the hanger installed, the tubing is finally lowered into the well and landed off, Fig 7(c).

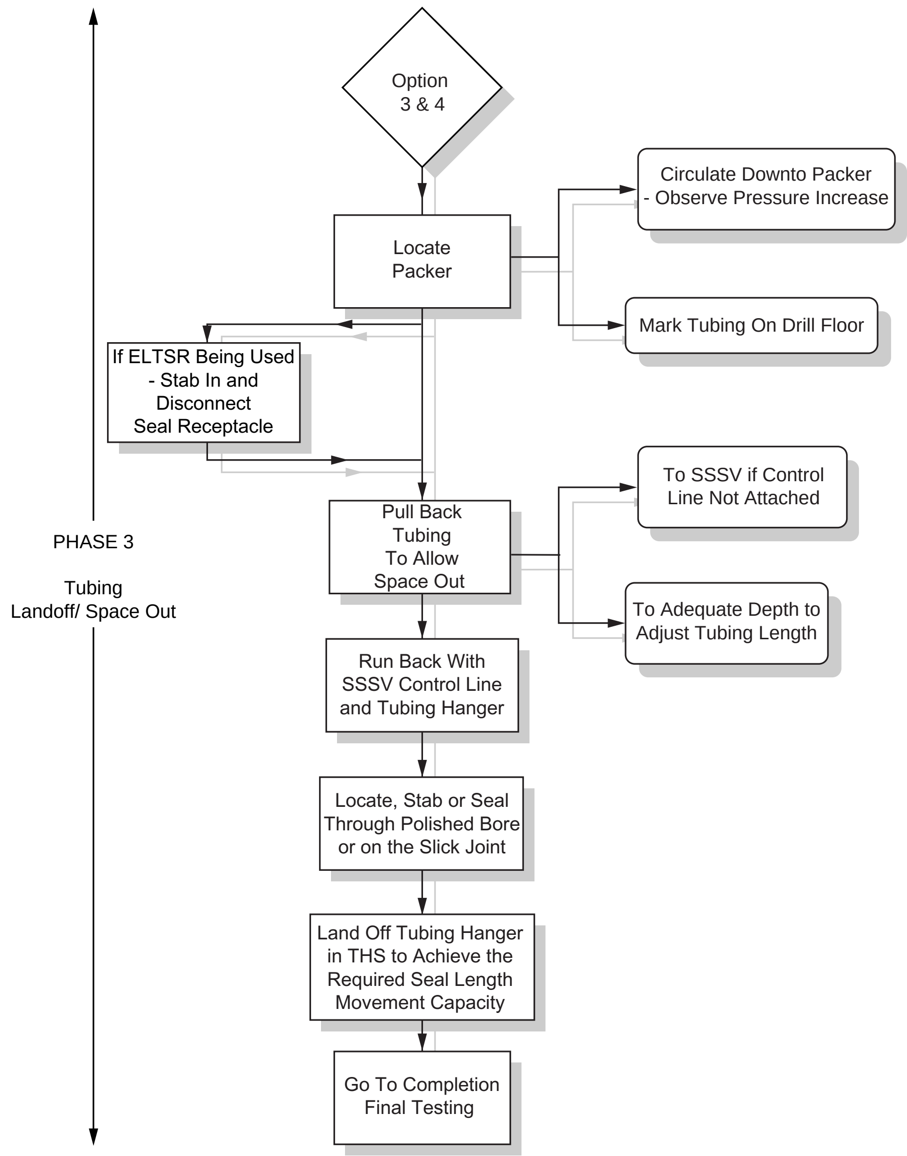


Figure 7(c)
Tubing land off / space out: packer pre-installed

(2) PBR and tubing seal completion

In this case the tubing seal assembly is lowered down to locate the top of the PBR. Again circulation can be employed when lowering the final 1-3 joints to locate exact depth of entry to the receptacle. After marking the string and pulling back to adjust the length of the tubing, on final lowering the tubing seals should be located at the desired position in the receptable, Fig 7(b).

3.4 Hydraulic Testing of the Completion (Fig 8)

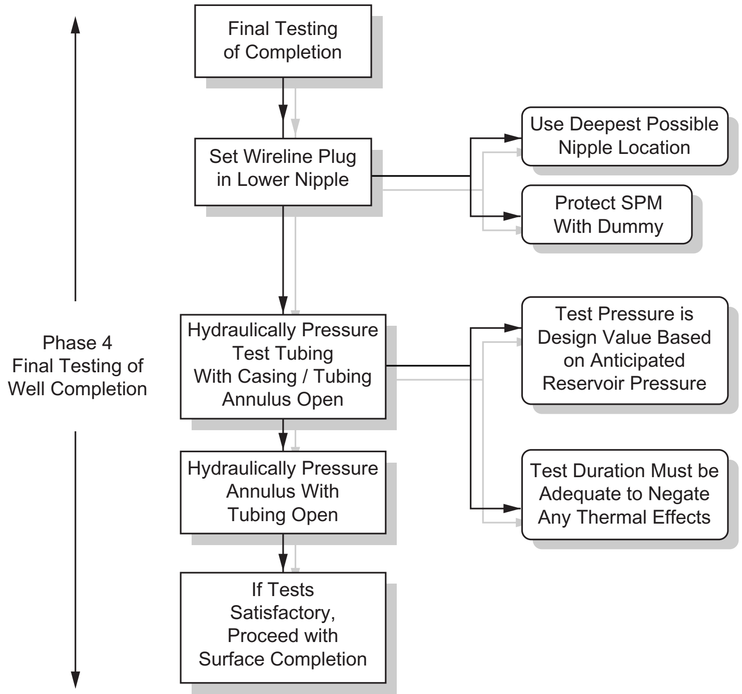


Figure 8
Final testing of installed completion string

The benefits of continuous, rigorous inspection and hydraulic testing of the completion string whilst the tubing is run in were discussed earlier in section 4.2. However, once the string is installed its composite integrity, both tubing and annulus must be checked. Provided no hydraulically actuated equipment exists in the completion string e.g. SPM with shear out valves, or hydraulic set packer, the string can be pressure tested in its entirety. This is the simplest approach.

In the case of setting a packer on a tubing string where subsequent tubing retrieval will necessitate unseating/ pulling the packer, it is preferable to pressure test the string before setting the packer. Final testing of the completion has the objective of hydraulically testing the following:

(1) the integrity of tubing joints/couplings.
(2) the integrity of seals in packer, seal assemblies, sliding sleeves, SSSV's etc.
(3) the integrity of hanger/wellhead seals for both pressure in the annulus or tubing.
(4) the hydraulic integrity of the production casing and wellhead.

Hydraulic testing of the tubing is normally conducted by monitoring either pressure or flow from the annulus. The formation must be exposed to high bottomhole pressure i.e. surface test pressure plus the hydrostatic pressure and should therefore preferably be isolated by installing a plug. A nipple should be installed for the purpose of accepting a plug and should be located as deep as possible e.g. in the tailpipe below the packer, or just above the packer if it is hydraulically set, to allow testing of the maximum length of the completion string. Hydraulically operated string components such as side pocket mandrel shear valves must be removed and replaced by a dummy sleeve.

The test tubing pressure utilised must reflect the reservoir pressure and designed operating pressures for the tubing. The duration of the test should again be adequate to allow differentiation between the gradually increasing annular temperature effect on the annular fluid volume and any potential leak channels. Initially, the annulus will be pressure tested against the packer and hanger seals with the tubing open. Any circulation beneath the packer will cause flow from the tubing.

3.5 Surface Completion of the Well

Prior to this stage, flow control of the well has been retained by the hydsrostatic pressure of the wellbore fluids and in an emergency, the ability to close off the well using the BOP stack.

Having successfully pressure tested the tubing and annulus and being satisfied that as far as possible the completion equipment will mechanically function as per specification, the final phase of completing the well can be entered i.e. installation of the Xmas tree and surface connecting flowlines, Fig 9.

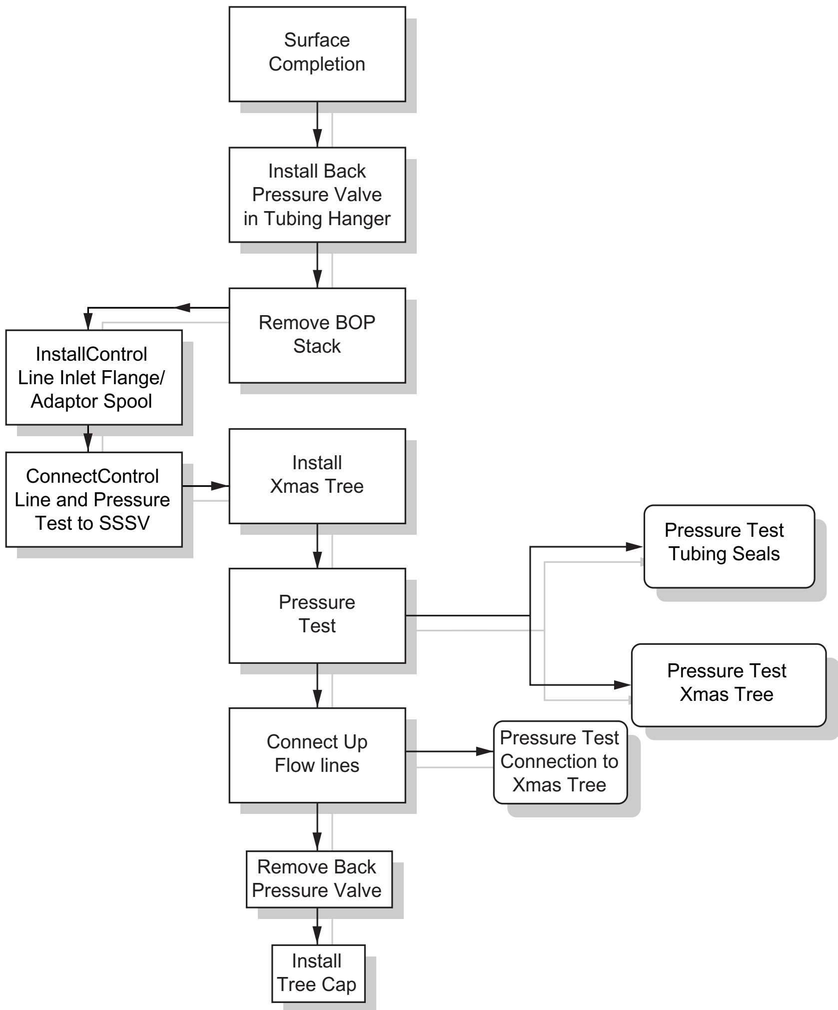


Figure 9
Surface completion of the well and testing

The first stage is the removal of the BOP stack and, as a precaution prior to this, a check valve is installed in the upper bore of the tubing hanger to prevent any potential backflow.

Subsequent to nippling down the BOP stack, the necessary flanges/ connections for the SSSV control line and for positioning the Xmas tree are installed. After mechanical installation of the Xmas tree, all seals and valves require to be tested. Upon successful completion of the pressure tests on the tree, the flowlines can be installed, connected and pressure tested. After this has been successfully completed, the BPV can be retrieved, as the entire completion can now accommodate safely, fluid production.

3.6 Production Initiation

If the well has been perforated prior to mechanical completion, the major task is one of placing the required fluid in the annulus to provide long term protection, and in the tubing to provide the hydrostatic drawdown or balance pressure conditions.

If the well has not been perforated then the fluid conditions could provide either an over or underbalance. The initial task will be one of installing and pressure testing a wireline lubricator to allow subsequent fluid circulation with a positive tubing head pressure THP. The means of circulation e.g. SSD or SPM must then be open and the tubing and annulus contents displaced to the required fluids. Normally the packer fluid in the annulus will function as a kill fluid whilst the tubing fluid will underbalance. At the end of the circulation there will therefore be a positive THP. This tubing head pressure can be reduced in the case of the unperforated well once the circulation path is closed off, to provide the required drawdown differential between bottomhole and reservoir pressures. In the case of the pre-perforated well, the well can be opened up for production whilst for the other wells, the perforating operation can be conducted, Fig 10.

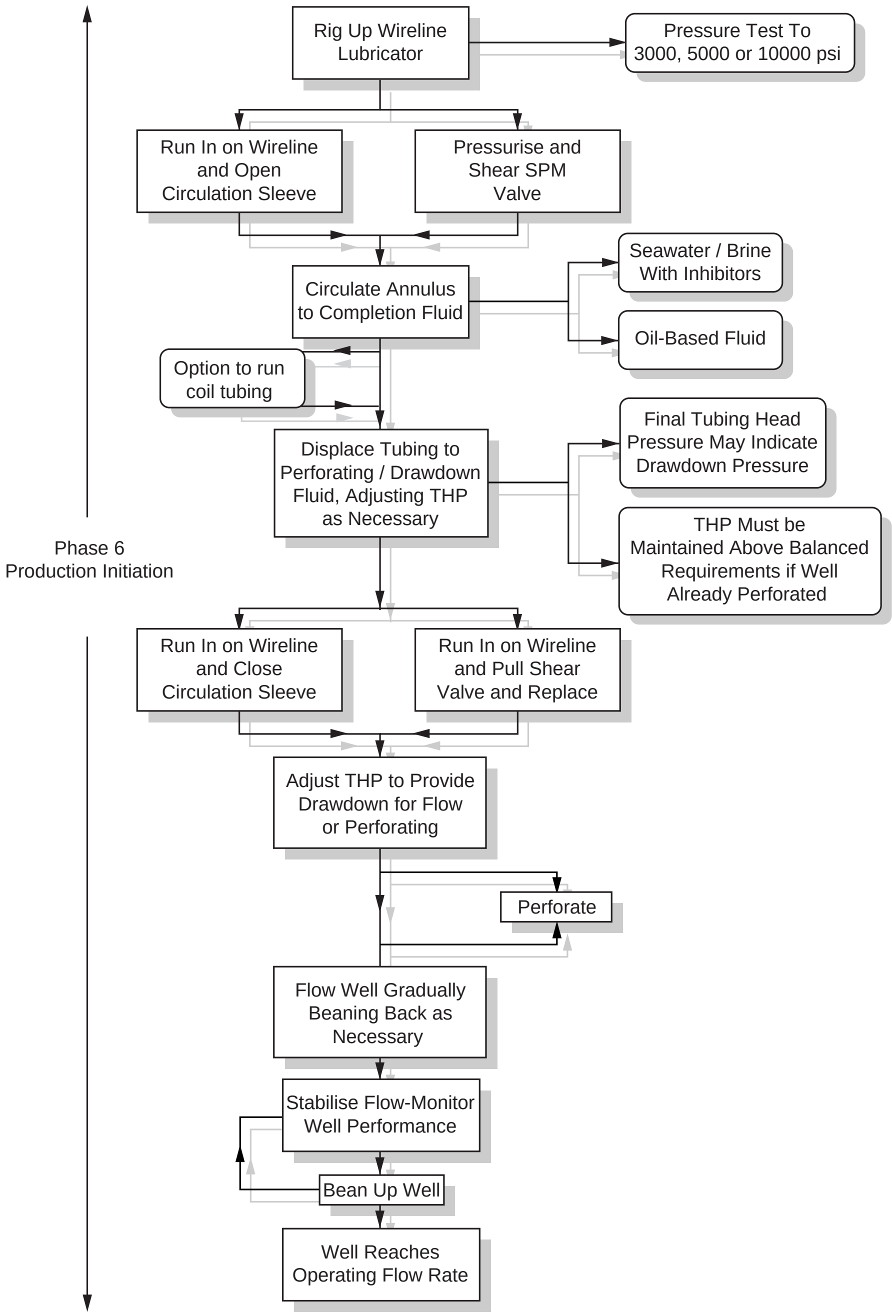


Figure 10
Production initiation

The well will initially be opened up with the objective of achieving stability rather than maximum attainable flowrate. The well should be sequentially beamed up to its operating flowrate over a period of several days.

4. REPORTS AND DOCUMENTATION

It is imperative that the completion installed is well documented with respect to:

(1) completion string equipment and string configuration

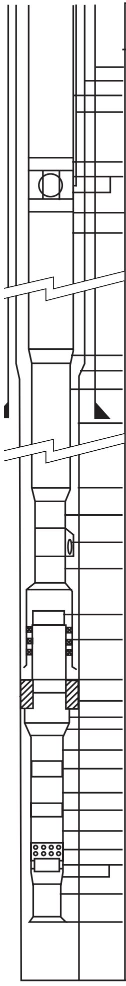
(2) a detailed record of the completion installation operation.

This is essential to allow for any post completion remedial evaluation if the well or completion fails to perform as expected, but more importantly, it provides the fundamental well information for well diagnosis, well re-entry and workover planning.

The documentation on the completion for retention should consist of:

(1) Completion or well status drawing. An example is shown in Fig 11. A single page drawing is concise but it may also be useful to attach dimensional sketches of the critical sub-assemblies.

Field - Platform Wells
Proposed Completion - Contingency For W.O.G
Single Packer (7 5/8" Tie Back Casing)



Depth ft TV> BDF	DESCRIPTION	Max OD ins	Min ID ins
	9 5/8" 47 lb/ft. VAM C95V Production Casing (Drift)		(8.525)
	7" 33.7 lb/ft. XL C75(I) Liner Tie-Back Casing	8.010	(6.640)
	5 1/2" 23 lb/ft. Hydril Super Eu C75(II) Range 3 Tubing	6.000	(4.545)
	Dual Monel SSSV Hydraulic Control Lines (2 x 1/4" OD)		
	5 1/2" x 6 ft. Flow Coupling. C75(II)	6.000	4.500
	(5 1/2" NOM OTIS RQ Landing Nipple. Valve-NoGO & Bore	4.125	2.250
± 1500	(For 5 1/2" DB Ball Valve Assy. Nipple-NoGO (Top PKG)		4.315
	(5 1/2" 23 lb/ft. Hydril SEU Box x Pin. Lower Packing		4.125
	5 1/2" x 6 ft. Flow Coupling. (As above)		
	5 1/2" 23 lb/ft. Hydril Super EU (As above)		
	Swage Nipple. 5 1/2" 23 lb/ft. x 5" 18 lb/ft. Hydril Super EU		
	7" Liner to 7 ?" Tie-back Casing x over		
	5" 18 lb/ft. Hydril Super EU C75(II) Range 3 Tubing	5.420	(4.151)
± 8000	9 5/8" Casing Shoe		
	7" 29 lb/ft. VAM C75(II) Liner		(6.059)
	Swage Nipple. 5" 18 lb/ft. Hydril SEU x 4" 13.4 lb/ft. Hydril PH6.		
	4" 13.4 lb/ft. Hydril PH6. C75(I) Range 2-1 Joint	4.625	(3.215)
	4" Camco KBMG-P SPM with DCK-2 Shear Valve	5.875	(3.215)
	Shear Valve Set at ---------PSI Differential, Kickover Tool OD	3.187	
	4" 13.4 lb/ft. Hydril PH6 - (As above)		
	4" Otis R Landing Nipple Packing Bore ID		3.125
	(Baker 30 ft. Tubing Seal Receptacle Type EL-1	5.750	3.373
	(5 1/4" x 43 x 31 (4" 13.4 lb/ft. H-PH6 Box x Pin)		
	(30 ft. stick joint - blank J slot - 10.000 lbs Upstrain Shear		
–	(Baker Anchor Tubing Seal Assembly. Type H-22		
	(Size 81 -FA-47 (4" 13.4 lb/ft. H-PH6 Box).		3.875
± 8400	(Baker Retainer Production Packer. Type FAB-1		
	(Size 85 - FAB-47 (5 1/2" 23 lb/ft. H-SEU Box Down).		4.000
	(5 1/2" x 6 ft 23 lb/ft. Mill Out Extension - Size 80 - FAB -47	6.000	(4.545)
	(Swage Nipple. 5 1/2" 23 lb/ft. x 4" 10.9 lb/ft. VAM (Special by baker).		
	4" 10.9 lb/ft. VAM C75(II) Pup Joint x 5 ft.	4.366	(3.351)
	4" Otis RD SSD. (Move up to close) Packing Bore ID		3.125
	4" 10.9 lb/ft. VAM C75(II) Range 2-1 Joint	4.366	(3.351)
	4" Otis RN Landing Nipple Packing Bore ID		3.125
	Nipple No-GO ID		2.907
	4" x 10 ft. Perforated Flow Tube (J55).		
	3 1/2" Otis XN Landing Lipple. Packing Bore ID		2.813
	(4" 10.9 lb/ft. VAM Box x 3 1/2" 9.3 lb/ft. Hydril CS Pin.) Nipple No.-GO ID		2.760
	3 1/2" 9.3 lb/ft. Hydril CS C75(I) Range 2-1 Joint	3.905	(2.867)
	Wireline Entry Guide (3 1/2" 9.3 lb/ft. Hydril CS Box)	3.870	2.997
± 9200	TD		

Figure 11 Well status drawing showing depth and dimensions of components.

(2) A copy of a petrophysical data log incorporating porosity, resistivity, gamma ray, cement evaluation and casing collar locator logs should be an integral part of the record, showing clearly the location and length of perforated intervals.

(3) Whilst not essential, a completion log can be of great benefit for diagnostic purposes when problems are encountered in completing other wells in the field or in workover planning.

SUMMARY

The installation phase of completing a well is as important to its economic success as the process of well design. However the actual process of running the completion is specific to the design.

In this section we have seen the generalised process of running a completion presented as a series of sequential flow chart covering the main elements of:-
Wellbore preparation
Running the completion
Perforating if required
Land off and space out of the tubing
Surface connection and tubing
Initiating production

Critical to the success of the well and facilitating both reservoir management and intervention is the preparation adequate, accurate documentation.

CONTENTS

LEARNING OBJECTIVES:

Having worked through this chapter the Student will be able to:

- Introduction to the variable nature of well interventions.

- Describe the inherent risks and need for careful diagnostics, planing and supervision.

- Describe the economic implications of a workover in terms of the need to protect the well production or injection capacity.

- List and describe the equipment and operational concepts involved in coiled tubing and hydraulic workover units.

INTRODUCTION

A production or injection well may be designed for maximum efficiency but will always be subject to failure or declining performance. These "failures" can be attributed to either:

(1) Mechanical malfunction or the need for redesign of the complete equipment to adapt to changing reservoir conditions

(2) Changes in reservoir performance or flow characteristics as a result of reservoir dynamics and recovery mechanism.

Interventions to address these changes are complex for the following reasons:-

(1) The completion is a complex mechanical system comprising components whose operation is inter-dependent

(2) The service environment can be extremely hostile:-

- High Pressure
- High Temperature
- Corrosive Fluids
- Severe Stresses both hydraulic and mechanical which can be cyclical

(3) In most cases we are dealing with a "live well".

In general terms intervention may occur on a producing or an injecting well and the operation is normally referred to as a **workover**.

1. GENERAL APPROACH TO A WORKOVER

Problems on wells can largely be associated with one of three areas, namely:-

(1) The reservoir
(2) The completion string
(3) The wellbore

Normally a problem on a production or injection well is evident by information gathered at surface, in relation to flowrate, pressure, composition etc. Before a problem can be rectified on a particular well, the nature of the problem has to be investigated and clarified, once this has been accomplished the options available to the company to intervene to correct the problem can then be drawn up and evaluated. In this evaluation process, it is important that technical issues can be considered such as

- The availability of the necessary equipment
- Experience in performing such operations
- The likelihood of success

In addition, it is also crucial that the economic benefits of the operation be fully appraised and evaluated to make sure that the option selected to correct the problem will yield the best probable economic benefit to the company.

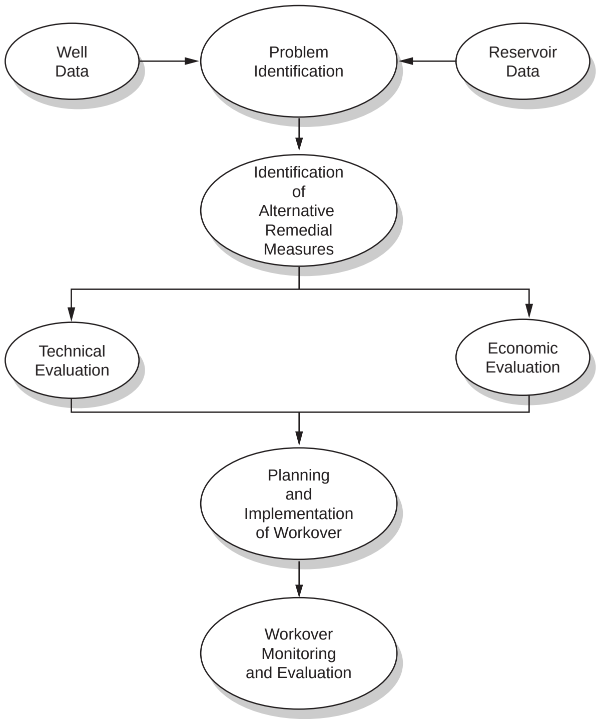


Figure 1
A Logical Approach to Planning and Conducting a Workover

2. TYPES OF INTERVENTION

Primarily in this chapter we are concerned with problems associated with the completion string. Problems associated with the reservoir can be investigated and evaluated using production logging and well test techniques.

In general, problems associated with the completion string can be classified as follows:

- Problems which arise in the tubing bore and which can be corrected by concentric through tubing operations

- Problems which necessitate the retrieval of the completion string from the well.

2.1 Internal Tubing Problems

Problems within the bore of the completion string can be related to:-

1. The failure and necessary retrieval/replacement of wireline components and coiled tubing

2. The installation operation of, retrieval or equipment within the tubing bore

3. The installation of equipment across the perforated interval or in the sump of the well to exclude water, gas or other production problems.

2.2 Tubing Retrieval Problems

There are a large number of problems which may occur on the well which necessitate tubing retrieval. These would include:-

(1) Mechanical failure of the tubing string, for example a leak or collapse of the tubing

(2) Inability to conduct tubing wireline equipment replacement through the internal bore of the string due to ID limitations - small tubing size.

(3) The necessary replacement of the completion string by an alternative design, for example to allow the installation of artificial lift.

(4) The replacement of the tubing string to optimise reservoir performance, for example to change the tubing string to a smaller size to better accommodate declining reservoir productivity or increasing water, oil ratio.

3. WORKOVER EQUIPMENT AND TECHNIQUES

These will be discussed with reference to two different categories namely:-

(1) Internal through tubing operations

(2) Tubing retrieval operations

3.1 Internal Through Tubing Operations

A number of techniques are available to access and intervene inside the production tubing including:-

- Conventional slick wireline operations

- Through Flow Line techniques for application in subsea wells

- Concentric tubing

In general terms the capabilities of conventional/subsea wireline and the Through Flow Line (TFL) techniques allow the replacement and installation of wireline operated equipment such as downhole valves, chokes, regulators and gauges. Wireline techniques have been discussed earlier in chapter 5.

Coiled tubing operations involve the insertion mechanically of a small bore tube which is unwound continuously from a reel and injected into the well, optionally under pressure. Coiled tubing is available in lengths up to 22,000 ft of continuous reel, depending upon outside diameter. It is available in diameters ranging from less than

1” to 7". In the North Sea for example the large diameter production tubing allows and physical access to larger diameter coil which is also required to maintain high annular velocity and hence coil of 2 - 2$^{3/4}$" OD being preferred. The major benefit of the technique is that it allows concentric operations to be conducted in the tubing. These operations can include:-

(a) Mechanical operations whereby devices within the tubing, can be operated (hydraulically or mechanically), retrieved or inserted.

(b) Circulation operations such as the placement of acid or other treatment chemicals, or cement to squeeze out at perforated intervals. In addition CT. can be used as a velocity string to extend the life of a production well where it is dominated by slippage.

The general configuration of a coiled tubing unit is shown in Figure 2. It consists of:-

(1) A reel of continuous tubing

(2) A tubing straightener or gooseneck

(3) An injector head which will drive the tubing into the well even if it is under pressure

(4) The work tools

For offshore applications the system is supplied as a series of fluid mounted modules.

Coiled tubing can assist in conducting the following range of operations:-

- Circulation of fluid placement within the wellbore
- Retrieval and installation of wireline or through tubing equipment
- Drilling or milling operations

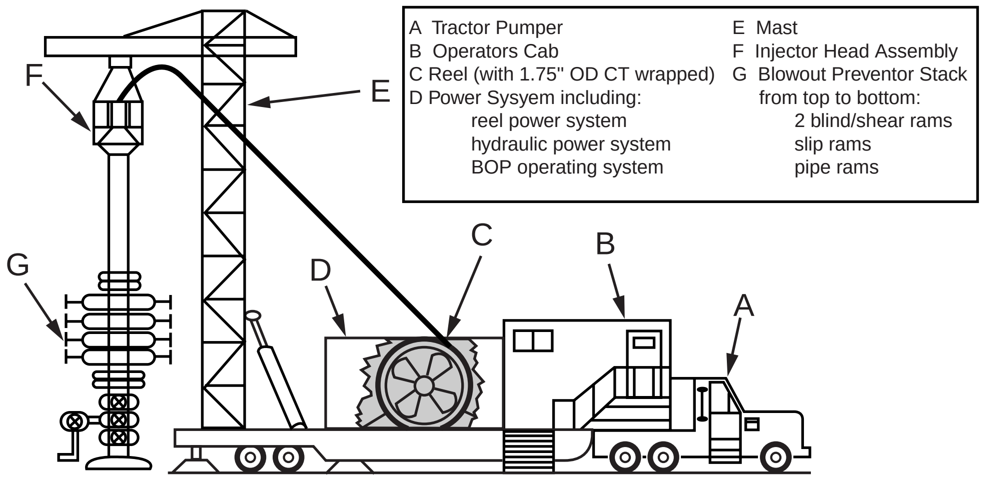


Figure 2 Schematic of Coiled Tubing Facility

Coiled tubing is available in a range of sizes and specifications. Some of the smaller sized coiled tubing is shown in Table 1.

Description	Trailer Mounted 1-inch O.D.TBG.	Truck Mounted 1-inch O.D.TBG.	Trailer Mounted 1-inch O.D.TBG.	Truck Mounted 1-inch O.D.TBG.	DNV Cerified Skid/Trailer Mounted 1 1/4-inch O.D.TBG.	DNV Cerified Skid/Trailer Mounted 1 1/2-inch O.D.TBG.
Engine	140	320	280	280	228	228
Reel Capacity	17,500 5334M	14,000 4267 M	15,000 4527M	15,000 4527M	17,500 5334M	15,000 4527 M
Reel Speed (FPM)	160 48,77 MPM	220 67,05 MPM	160 48,77 MPM	220 67,05 MPM	220 67,05 MPM	220 67,05 MPM
Injector Capability (LBS)	12,000 5488 Kg	12,000 5448 Kg	24,000 10896 Kg	24,000 10896 Kg	24,000 10896 Kg	24,000 10896 Kg
Max. Working Pres (PSI)	5,000 352 Kg/Cm^2	5,000 352 Kg/Cm^2	5,000 352 Kg/Cm^2	5,000 352 Kg/Cm^2	5,000 352 Kg/Cm^2	5,000 352 Kg/Cm^2
Service	STD/H_2S	STD/H_2S	STD/H_2S	STD/H_2S2	STD/H_2S2	STD/H_2S2

Table 1 Coiled Tubing Specifications

If a coiled tubing unit is available, it represents an economic way of conducting a whole range of workover operations. It's principal advantage over wireline arises from an ability to generate much higher tensile stresses in pulling operations and also importantly it offers the capability to circulate within the tubing. Depending on the depth of the well, coiled tubing can also be used to install equipment through the tubing string e.g. into the area beneath the tail pipe.

The installation of through tubing bridge plugs for water shut off is a major application in the North Sea.

It is likely that coiled tubing will be a fundamental technique in the servicing and operation of horizontal wells, by not only enabling tubing to be operated, which would be conventionally done by wireline but also to allow placement of fluids and hydraulic offloading of the well.

3.2 Tubing Retrieval Equipment

In general terms, the requirement for pulling tubing may be either full retrieval of the tubing or alternatively partial retrieval of the tubing string to a depth whereby components can be accessed at the surface, e.g.:- the retrieval of tubing to allow access and replacement of a tubing retrievable sub-surface safety valve.

The major requirements equipment for such operations is that they would be able to:-

(1) Withstand the tensile stresses created by pulling tubing and any overpull which may exist, for example, prior to the release of downhole production packers

(2) The ability to pull tubing out of live wells i.e. where a tubing head pressure exists at surface

Equipment available to conduct such operations could be either:-

(a) A full drilling rig with the necessary BOP equipment and the capacity to pull tubing.

(b) A concentric unit which can be installed over the producing well.

3.2.1 Concentric Workover Unit

A concentric workover unit consists of a double slip system which will engage on a length of tubing, one set of slips will be travelling and used to reciprocate on a cyclic basis and withdraw tubing, the other set of slips will be static and will be used to clamp and pull tubing into position whilst the travelling slips are re-positioned on the tubing. A schematic of a concentric workover unit is shown in Figure 3. A variety of units are available with characteristics as shown in Table 2.

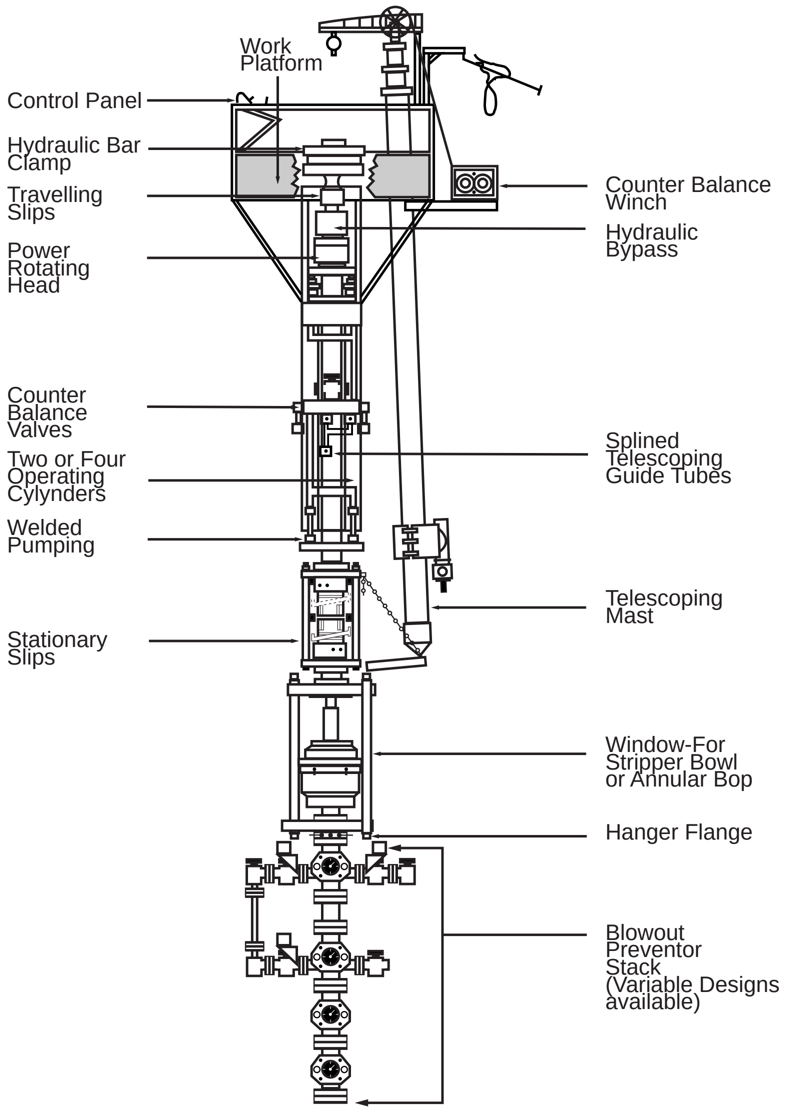


Figure 3
Hydraulic Workover Mast

Table 2
Hydraulic Workover Unit Specifications (Halliburton)

				MAX LOADS AT 3150 PSI			POW.ROT HEAD
UNIT	BORE SIZE IN.	NO. OF HYD. CYLIN.	STROKE LENGTH FT.	REGULAR LIFT LBS.	REGEN LIFT LBS.	SNUB LBS	MAX. TORQUE FT-LB AT 3000 PSI
120k	4 1/16	2	9	120,000	60,000	600,000	235
200k	7 1/16	2	9	200,000	100,000	100,000	4800
200k	11 1/8	2	9	200,000	100,000	100,000	6400
250k	7 1/16	4	12	250,000	108,000	100,000	4800
400k	11 1/8	2	9	400,000	200,000	200,000	6400
400k	11 1/8	4	12	400,000	200,000	165,000	6400
600k	11 1/8	4	9	600,000	300,000	300,000	6400

4. SELECTION OF A WORKOVER RIG

A number of factors will influence the selection of a workover rig including:-

(1) The nature of the operation to be conducted e.g. tubing size and hence the suspended weight of the tubing string, pressure control requirements for well re-entry etc.

(2) Logistical constraints - location of well, proximity to operating company base, availability, space on rig/platform, crane lift capacity.

(3) Economics - cost, availability and its impact on deferred production.

The reservoir characteristics for example:-

Type of fluid
Fluid contaminants e.g. H_2 S content
Pressure, temperature, fluid rate etc.
Depth of well

5. WORKOVER BENEFITS

In conducting a cost benefit analysis of the proposed workover we must consider the following factors:-

- Criteria and probability for technical success

- Criteria and probability for economic evaluation

Change the well function or adapt to changes in reservoir management objectives

The benefits of a successful workover can be significant. These could be purely technical or they may have safety or economic implications. The benefits could include:-

(a) Enhancement or restoration of safety

(b) Reduction in operating costs

(c) Accelerate the production revenue

(d) Increase the ultimate recovery

5.1 Evaluation Considerations

The question arises as to what measures of success should be used? A successful workover should be assessed both in terms of its technical and economic success. However, the evaluation of success may be difficult because of the problems associated with defining the nature of the well problem and the probability for success with the optional responses. This will be dependent on some of the following:

- The complexity of the workover.
- Data and diagnostic constants e.g. cost, tools, manpower.
- Limitations in terms of manpower and equipment resources

5.2 Economic Benefit

The question of profitability and evaluation can be done with respect to two different approaches:-

(a) Absolute or incremental profitability measures that do not involve time or the alternative investment of the funds that would be directed to the workover.

(b) Time dependent values i.e. where we consider the present value of future revenue and costs.

When considering the evaluation of the economics of a workover we must consider alternative investments within the company or pre-set minimum rate of return as specified by the company. In terms of profitability measures there are a number available:-

5.2.1 Absolute Measures of Profitability

Pay back-period – by this approach the period is determined when the project revenue would repay the costs. Figure 4. It is therefore a simple measure, but not realistic in terms of considering alternative investment strategies.

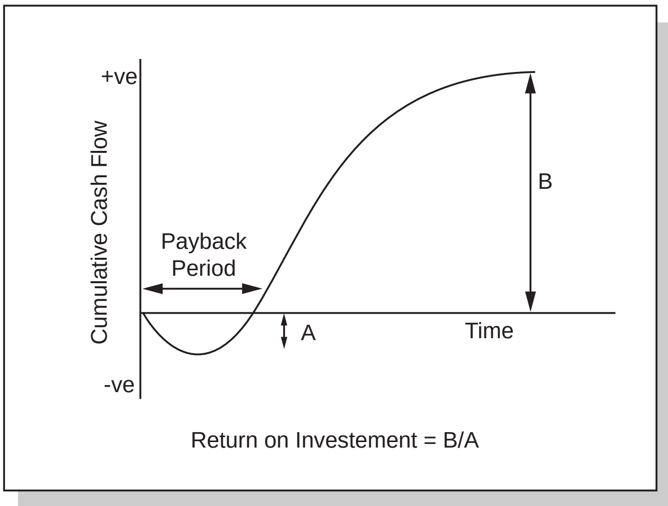


Figure 4
The Payback Period

5.2.2 Measures which consider Time Value of Cash Flow

1 Discounted Cash Flow
In this technique the future cash flows are discounted back to a standard reference time by use of a standard interest rate specified to the project.

2 Net Present Value
This considers the current value of the revenue which will be associated with the workover compared to the actual cost of the workover in present day terms, the benefit of the net present value approach is that it can be used to incorporate risk factors to take into account uncertainty in the evaluation.

3 Internal Rate of Return
This is the definition of the interest rate on revenue which would generate a net present value of zero therefore provides the maximum discount rate of the project (Figure 5).

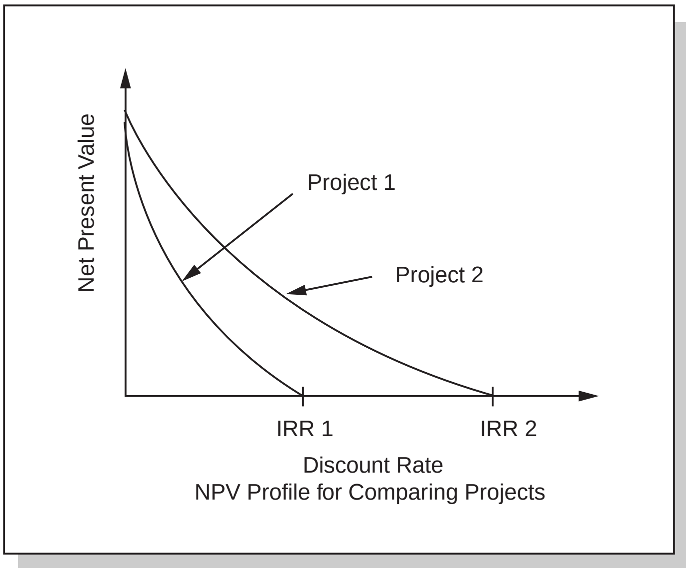


Figure 5
Internal Rate of Return

4 Production Rate Evaluation
In this technique there is no consideration of economics, but purely the comparison between pre and post workover production rates, this can be expressed in terms of the benefit fraction or an incremental gain or the ratio of the production rate increase to the pre workover rate. It has considerable limitations.

5 Cost Benefit Analysis
By this approach we look at the cost associated with the project in terms of:

(a) Direct workover costs

(b) Deferred oil production

(c) Impact on production capacity

In terms of benefits we look at the value of the incremental recovery. This technique allows alternative interest opportunities to be considered and the level of risk to be incorporated.

The idealised benefit response from a workover is shown in Figure 6.

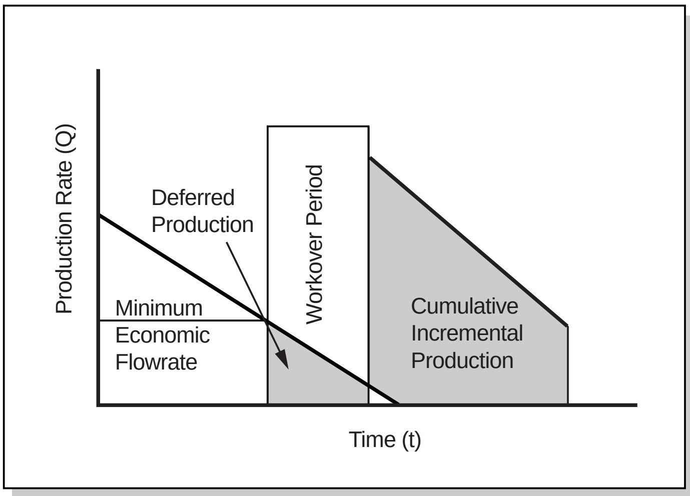


Figure 6
Idealised Fluid Recovery Benefit Profile Resulting from a Workover

SUMMARY

In this section we have reviewed workover or intervention operations. In general the following points should be drawn.

(1) Intervention can be conducted through tubing or require tubing retrieval depending on the nature of the problem.

(2) A range of optional solutions exist for most problems.

(3) We are dealing with a live well and hence safety and protecting the productivity / injectivity index are important considerations.

(4) Data is essential to the diagnosis of problems, as well as the collation and evaluation of options both technically and economically.

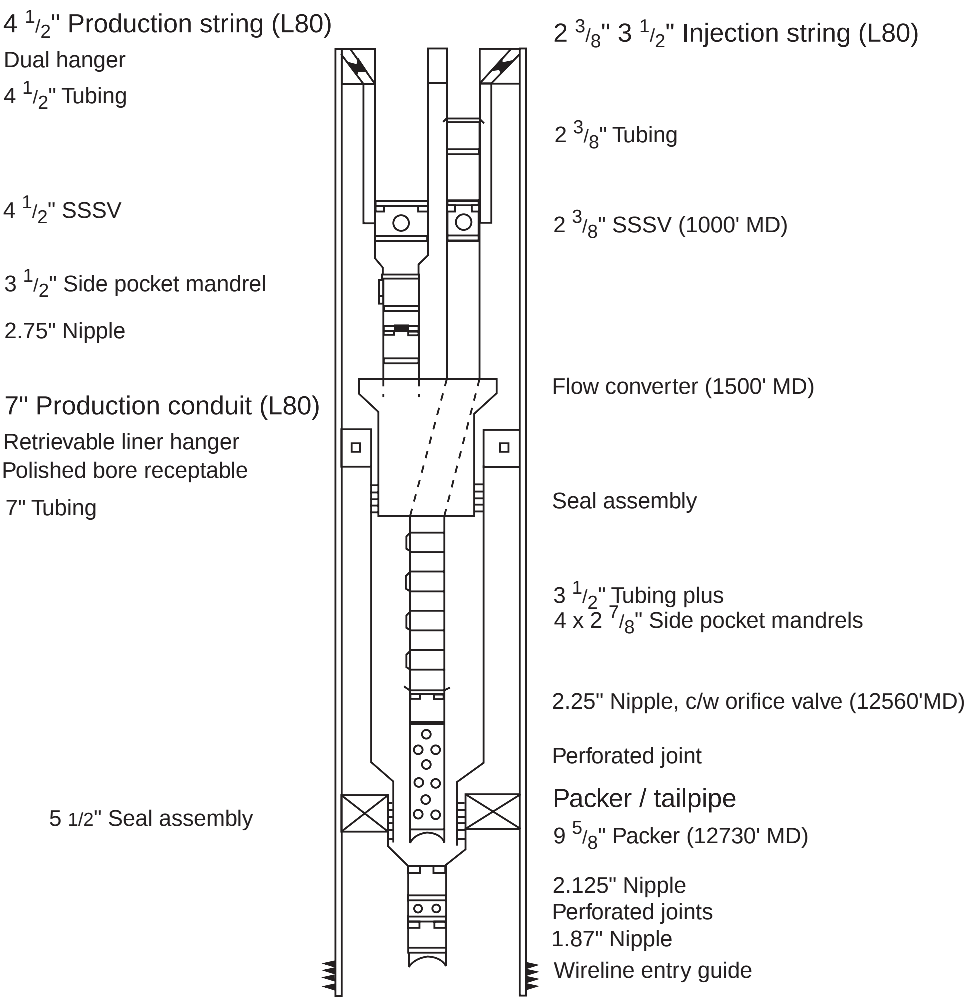
EXERCISE 1.

WELL PROBLEMS AND WORKOVERS

For the attached completions, identify:

(a) The principal potential sources of the problem where a build up in annular pressure is observed in completion (a) and (c).

(b) Assuming that we wish to pull the tubing from the well how would you service the well for the completions depicted in figure (b) and (d).



Dual concentric gas lift completion

Figure (a)

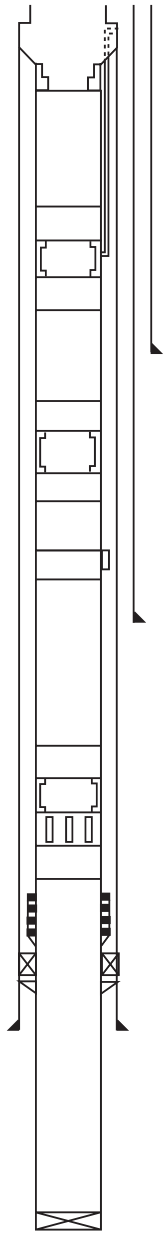
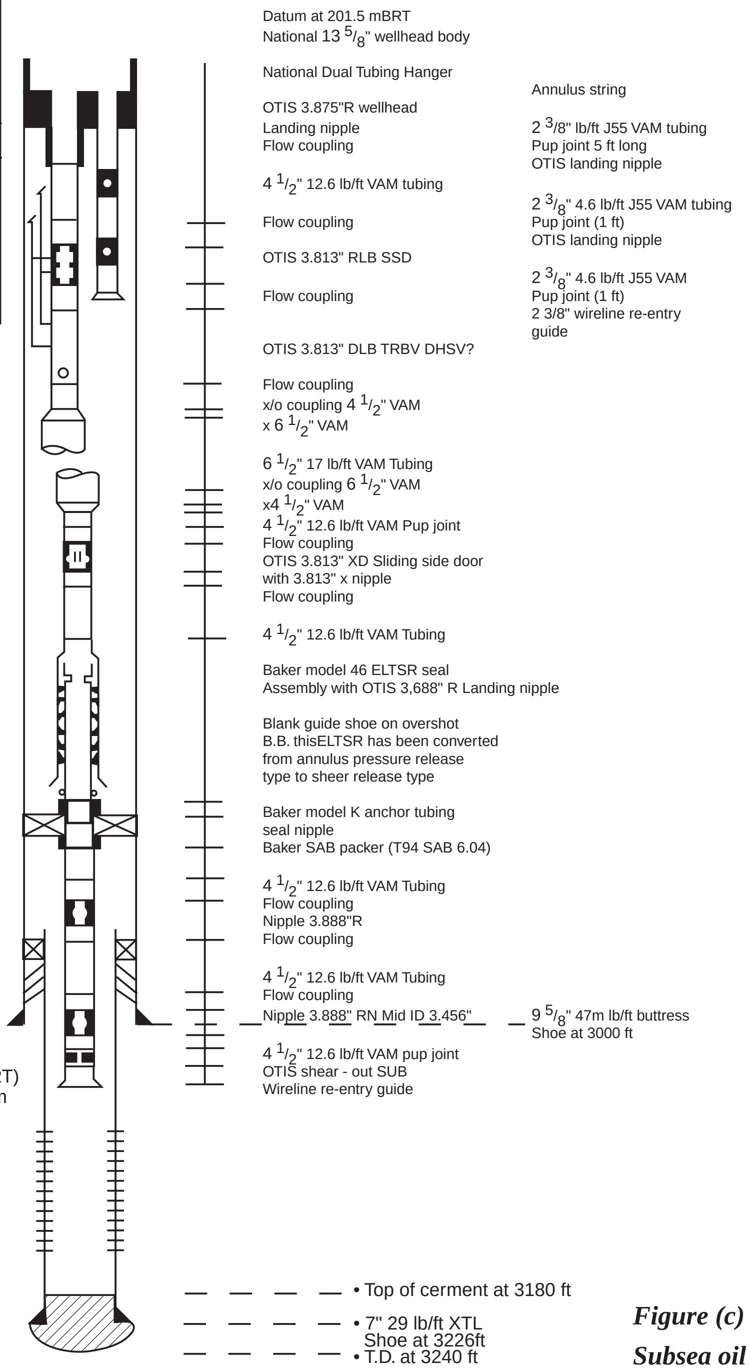


Figure (b) 7" Oil Production Completion

PRODUCTION Length (m)	Depth (m)
0.18	201.50
0.41	201.88
0.48	202.09
23.28	202.55
1.80	225.83
2.85	227.63
4.07	230.48
1.60	234.55
0.24	236.35
2522.43	236.59
24	2759.02
30	2759.26
1.82	2760.56
1.18	2762.38
1.72	2763.66
12.87	2765.26
14.17	2778.15
3.64	2792.32
206.60	2796.16
1.76	3001.66
4	3003.76
.81	3003.76
69.86	3005.57
1.80	3075.43
0.39	3077.23
3.08	3077.62
0.30	3080.70
1.62	3081.00
	3082.82

All depths are mBRT

ANNULUS Length (m)	Depth (m)
0.18	201.50
0.41	201.68
0.43	202.09
0.30	203.52
1.55	203.82
0.34	205.37
0.38	205.71
0.15	206.9
	206.24



Perforations (mBRT)
3106.3 - 3151.0m

Figure (c)

Subsea oil producer.

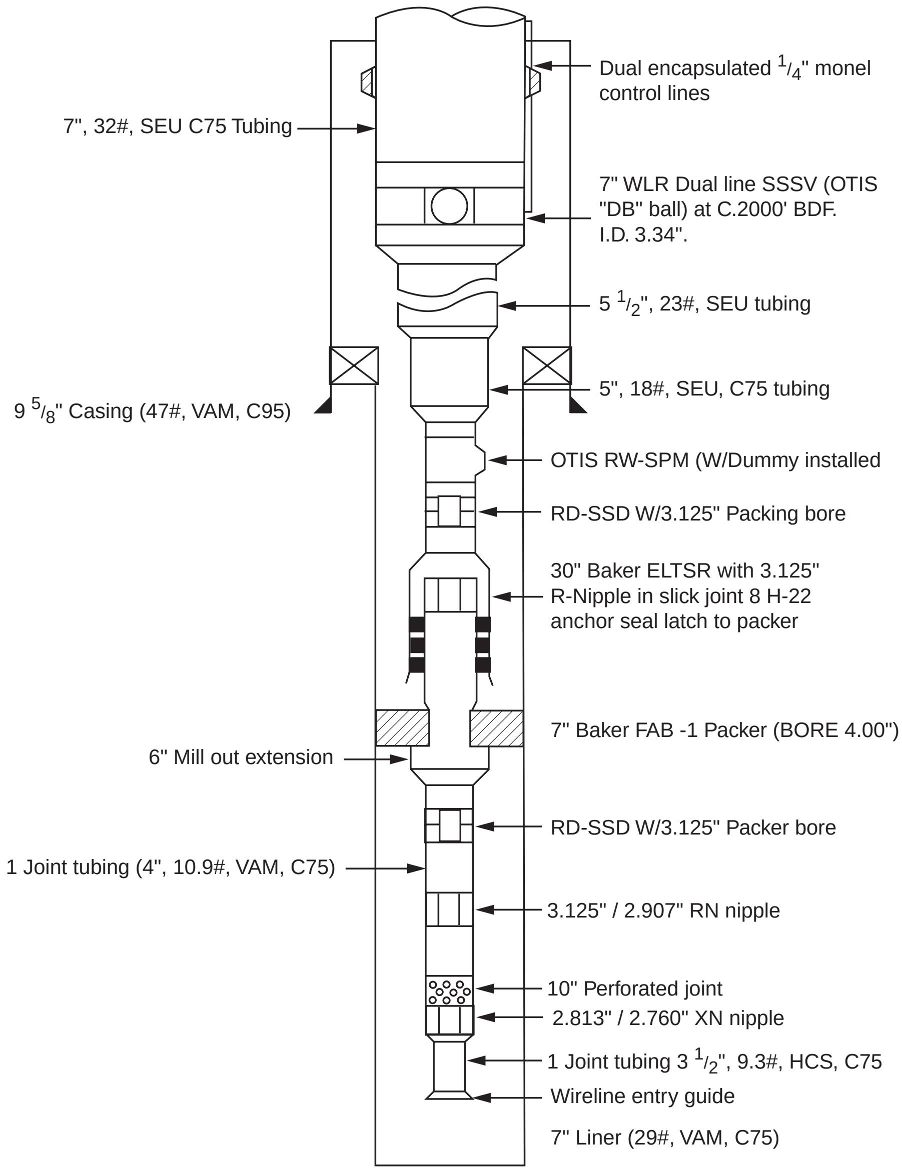


Figure (d)

Large bore oil producer.

EXERCISE 2.
PROBLEM WELL DESIGN

1. A well having been on production for several years starts to show signs of declining production rate. There are no real signs of a change in water cut. List some of the probable causes and what other indicators would assist in your analysis of the problem.

2. A well starts to cut water at very high rates, what would you expect to see happening progressively in the future in terms of flowrates? Any other changes that you may wish to watch for?

3. After workover in which the well was killed, the well only flowed at 50% of its pre-workover rate. What questions would you ask regarding the kill procedure, fluids used and the leak off history?

4. For the following damage scenarios, how would you expect the well to respond in terms of oil production rate to clean up post-workover:

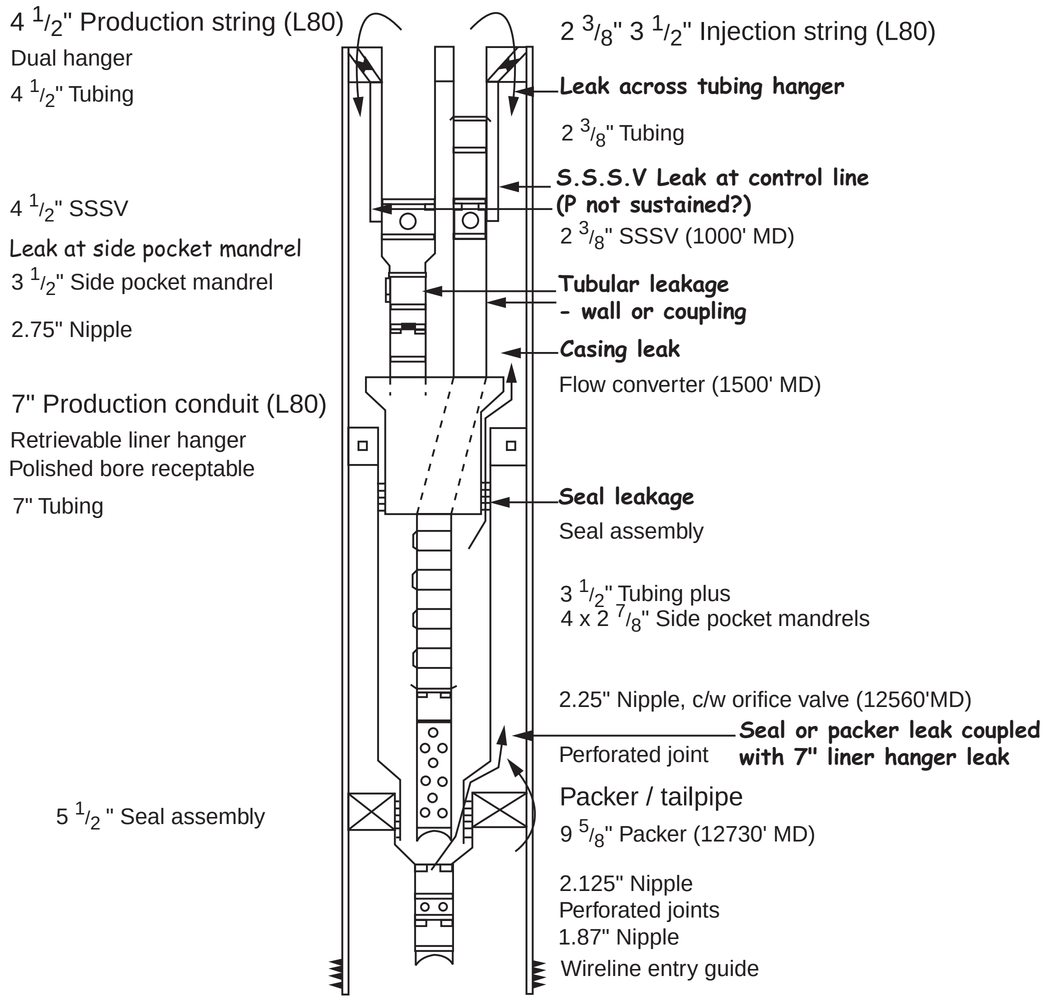
(a) Sensitive sandstone completed with a low salinity workover fluid.

(b) Loss of large volume of water based fluid to a clean oil bearing sandstone.

(c) Use of calcium carbonate kill slurry.

(d) Leak off of fluid into the reservoir and creating an emulsion with the crude oil.

SOLUTION TO EXERCISE 1



Dual concentric gas lift completion

Figure (a)
Solution

PRODUCTION Length (m)	Depth (m)
0.18	201.50
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23.28	202.55
1.80	225.83
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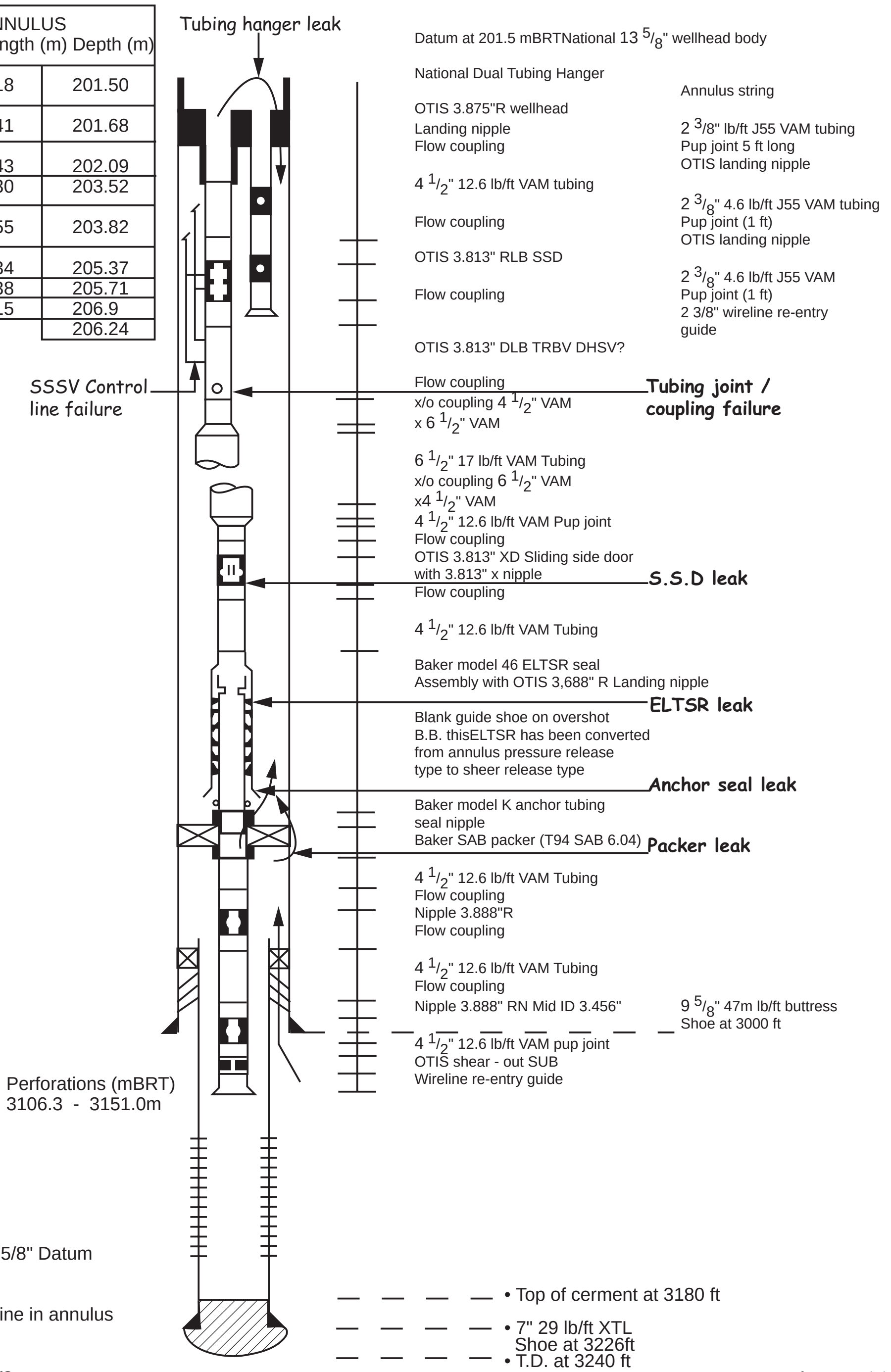
0.30	203.52
1.55	203.82
0.34	205.37
0.38	205.71
0.15	206.9
	206.24



All depths are mBRT

RTE :25.19mAMSL
201.5m Above 13 5/8" Datum

Fluid in place:
1.59 S.G. brine in annulus
Oil in tubing

Pressures :Annulus -zero
production -zero
(0.3500 psi under DHSV)

Figure (c)

Solution

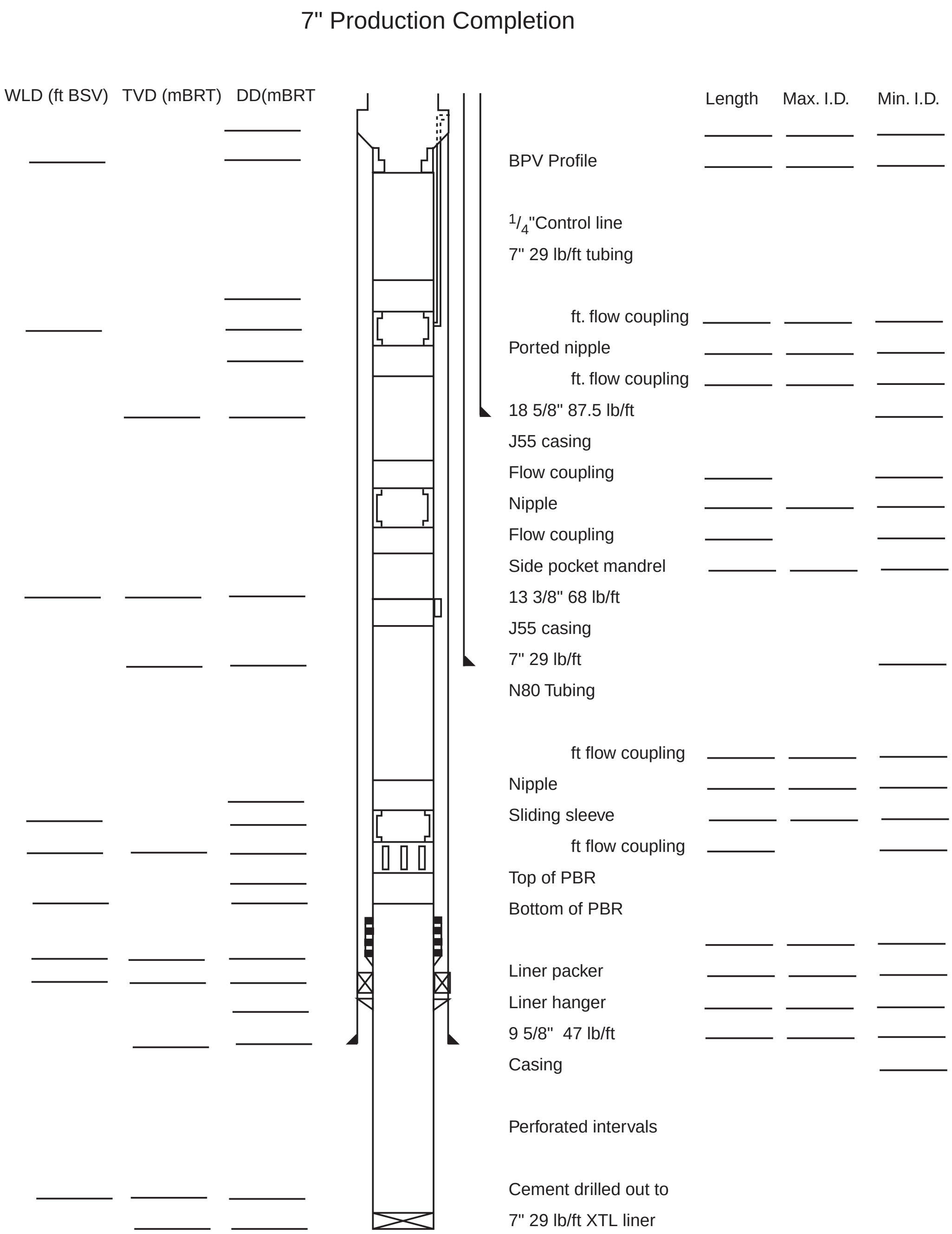


Figure (b)
Solution

Solution for completion (b).

1. Open SSD and reverse circulate tubing holding $P_{BH} > P_{RES}$.
2. Run and set threw tubing bridge plug.
3. Observe well and set BPV in tubing hanger.
4. Remove Xmas tree and nipple up BOP.
5. Commence pulling tubing.

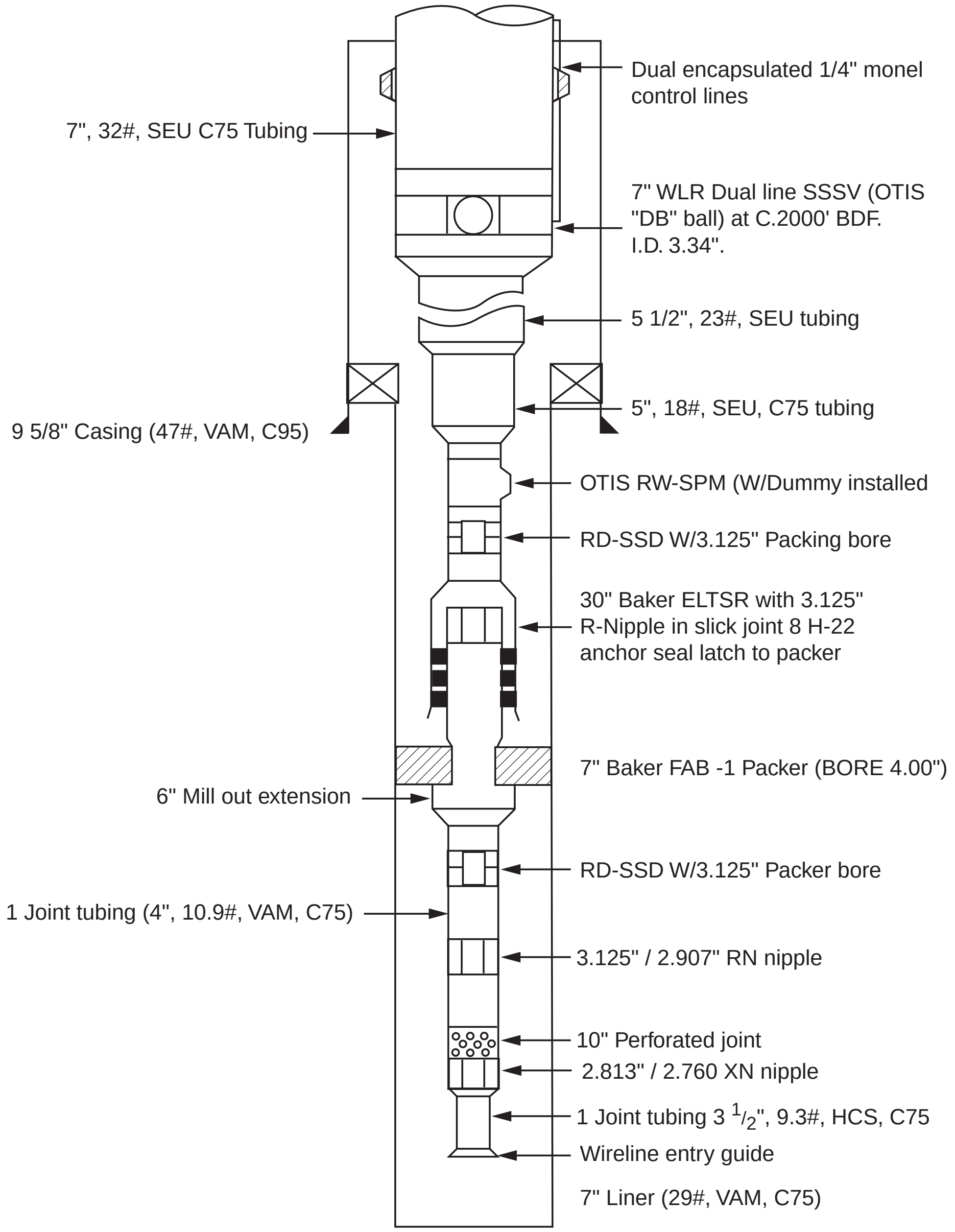


Figure (d)
Solution

Solution for completion (d).

Assuming 7" packer and tail pipe not to be pulled

1. Rig up W/L or CT and open SSD. (Check if W/L can be run through SSSV?)
2. Reverse cinulate out hydrocarbons and replace with kill weight fluid.
3. Observe well dead at surface.
4. If dead either
   (a) Set plug in 3.125" RN nipple or
   (b) Bullhead fluid below SSD into formation and then 4 (a).

5. Observe well dead.
6. Set BPV in tubing hanger nipple.
7. Remove Xmas tree and nipple up BOP.
8. Pull BPV.
9. Commence pulling tubing.

SOLUTION TO EXERCISE 2

1. Pressure depletion
   Fines migration
   Asphaltine / wax deposition
   Scaling in perforations and tubing.

Indications
   Solids production in fluid
   Chemical analysis of oil.

2. • Tubing will load up with water - high hydrostatic head pressure drop / reduced flowrate.

   • Production of fines from connate water film.

   • Possible destabilisation of sand / dissolution of calcite cement yielding sand production with possible decrease in slurry factors and higher liquid production rates.

3. Key to this is losses.

   • How much cumulative W/O fluid loss ?

   • Compatibility of W/O fluid with formation rock and oil?

   • Bottom hole pressure and overbalance.

   • Running speeds of tubing etc.

4.
   (a) No long term improvement - swelling clays lead to reduced absolute permeability.

   (b) Deferred production with no permanent loss in production assuming no side reaction damage.

   (c) Depends on the ability to remove with acid. Unlikely to recover 100% of production

   (d) Drastic and permanent loss in production.

CONTENTS

LEARNING OBJECTIVES:

Having worked through this chapter the Student will be able to:

- Classify the problems which occur in the production systems.
- Relate the problems to the main components of the system.
- Understand the interaction of the reservoir drive system and its effect on the overall production.
- Identify the main remedial actions available to the Production Engineer.
- Understand the financial implications of the proposed remedial program.

INTRODUCTION

The production system comprises:-

(1) The reservoir and its communication flow path with the wellbore.

(2) The wellbore comprising the production and intermediate casing including the cement sheath and sump.

(3) The completion which comprises the tubing and its components, the wellhead and xmas tree.

The above definition is comprehensive and as such it indicates the variety of areas where problems can occur.

In this chapter we will consider the following:
- the source of problems in injection and production wells
- the responses and options to deal with the problems

THE SOURCE OF WELL PROBLEMS

Potential problem areas within the production system are numerous and occasionally sequentially interactive, e.g.

(1) Inadequate cementation during placement or its subsequent removal, can lead to casing corrosion.

(2) Inadequate formation strength (or intergrain cementation) can lead to:
  (a) initial loss in productivity
  (b) inability to conduct effective wireline operations
  (c) erosion and failure of downhole or surface equipment.

The most frequent occurrence of well problems are grouped into general classifications as shown in Figure 1, namely:
- the reservoir
- the wellbore
- the completion

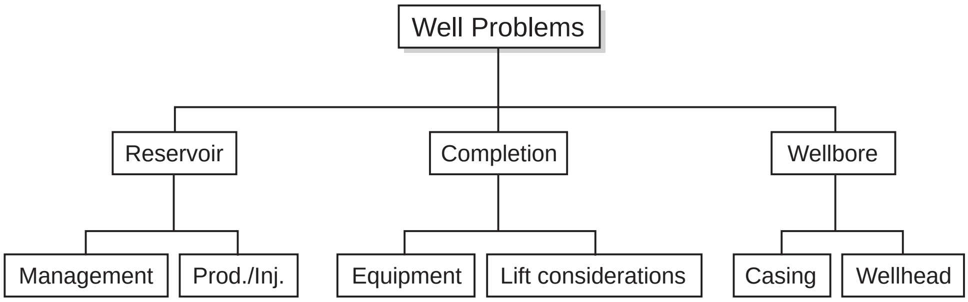


Figure 1
The sources of well problems.

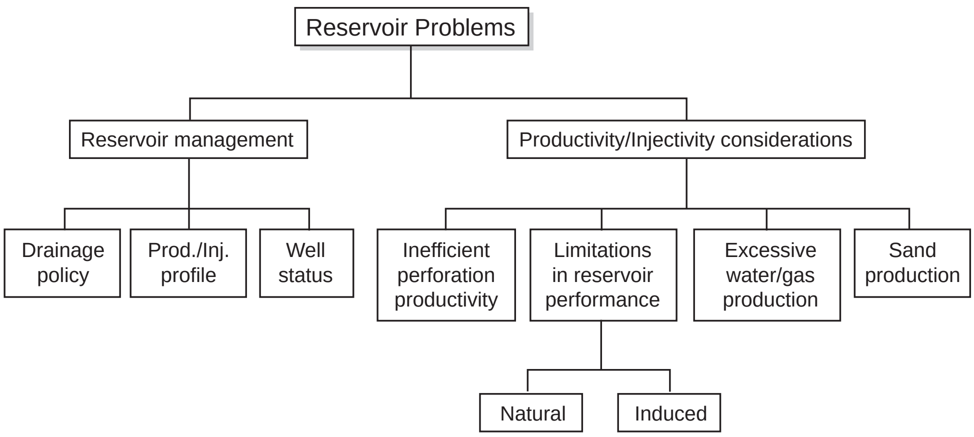


Figure 2
Reservoir related problems.

1.1 Reservoir Associated Problems

Reservoirs are highly complex geological structures which must be effectively managed if they are to be optimally economic. There are a number of fundamental reasons why reservoirs generate problems which necessitate workovers:

(1) Reservoirs are initially developed with limited data and hence an incomplete understanding of their physical characteristics. This limits the accuracy with which they can be modelled for planning purposes.

(2) Reservoirs exhibit a dynamic response to production and injection. This implies that their response has to be modelled, evaluated and updated periodically. If necessary, alternative methods for production or reservoir depletion have to be evaluated and possibly implemented.

(3) Production equipment has a finite working life which depends not only on its application but the way it is installed and utilised.

Reservoir associated problems can generally be classed as either related to
- ***productivity/injectivity considerations***

or
- ***reservoir management objectives*** (Figure 2).

1.1.1 Productivity or Injectivity Problems

The performance of a reservoir depends upon the optimum utilisation of reservoir pressure. Attention has to be given to the location and magnitude of pressure loss in the system. There are four major categories of problems identified in this area namely:-

(a) inefficient productivity/injectivity due to the perforations
(b) limitations on reservoir performance
(c) excessive water or gas production
(d) sand production

(a) Inefficient Productivity/Injectivity Due to the Perforations

The perforations through the wall of the casing, can provide a critical constraint on the fluid communication between the wellbore and the reservoir. The productivity of a perforated completion depends upon the following characteristics:-

(1) shot phasing i.e. angular orientation
(2) shot density i.e. number of perforations
(3) diameter and length of perforations
(4) perforation damage due to compaction and infiltration
(5) formation anisotropy

(b) Limitations on Reservoir Performance

There are many factors which will influence the capacity of a reservoir to “deliver” fluid into the wellbore. Some of these will exert a controlling effect. It is important however, to distinguish between ***natural*** and ***induced*** limitations.

The simplest mathematical relationship which defines the productivity of a well is the steady state radial flow equation:-

$$P_e - P_{wf} = 141.2 \frac{q_s \mu_s B_s}{K_s h} In \frac{r_e}{r_w} \qquad (1)$$

where

	P	=	pressure, p.s.i.
	q_s	=	flowrate of phases STB/d
	μ_s	=	fluid viscosity
	B_s	=	formation volume factor of fluid 's'
	K	=	permeability of rock to fluid 's'
	r	=	radius, ft.
	h	=	vertical thickness of reservoir

and subscripts

e	-	relates to outer radius of reservoir	
wf	-	bottom hole flowing	
w	-	wellbore	
s	-	fluid phase e.g.	o - oil
			g - gas
			w - water

The flow of fluid in the reservoir towards the wellbore is controlled by:

(1) reservoir pressure

(2) reservoir size and its ability to maintain pressure i.e. the reservoir drive mechanism

(3) reservoir fluid mobility i.e. the ratio of the permeability of the rock to that of the fluid i.e. to the fluid's viscosity.

$$Mobility\ Ratio\ M_o = \frac{K_o}{\mu_o} \qquad (2)$$

where the subscript 'o' refers to the oil phase.

It must further be recognised that reservoir performance limitations may be either natural or induced.

(i) Natural Limitations on Reservoir Performance

From equation (1), it can be seen that the flowrate q depends directly on the pressure drop across the reservoir (P_e - P_{wf}). A linear decline in reservoir pressure will be matched by an inversely proportional drop in production rate. Almost all reservoirs will observe a decline in pressure as fluid is produced. The rate of decline will depend upon the volumetric capacity of the reservoir compared to the volume of fluid withdrawn, and the ability of the fluids to expand or fluid inflow to occur into the reservoir, to compensate for depletion. Reservoirs will generally demonstrate less of a decline in pressure if:

(1) they contain light oil or gas (solution gas or gas cap drive)

(2) if they possess a high G.O.R. (solution gas or gas cap drive)

(3) they have good aquifer support (water drive).

The ***rock properties*** will also influence the well productivity as defined by the permeability K in equation (1).

The absolute permeability is a measure of the resistance to flow of a specific fluid through the porous media and depends principally on the pore size and morphology. In situations where more than one fluid occupies the pore space, it also depends on the relative magnitude of the fluid saturation in the pore space. In such cases, the permeability to a specific fluid is adjusted by a saturation dependent term known as the relative permeability.

e.g. $K_o = k_{ro}.K$ (3)

where K_o = permeability to oil
k_{ro} = relative permeability to oil
K = absolute permeability of the rock to fluid

The indigenous saturations found in oil and gas reservoirs are such that these phases are the mobile phases. However, when the pressure in an oil reservoir with solution gas drive, falls below the bubble point, the gas saturations will increase until it becomes mobile and thereafter both gas and oil flow through the pore space (Figure 3). This is a natural phenomenon to be expected in a solution gas drive reservoir with a resultant steady decline in oil production rate.

The viscosity of the fluid in the reservoir will have an inversely proportional effect on production rate. Heavy crude oils will particularly experience this as a limitation on their production performance.

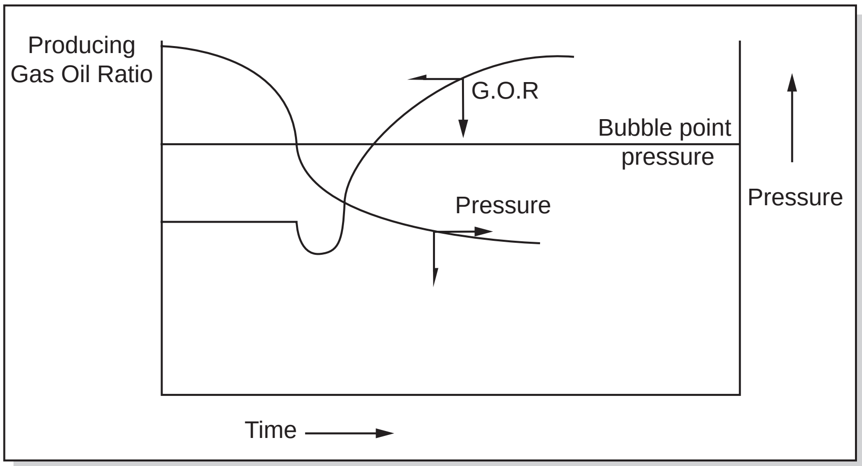


Figure 3
Production history for a solution gas drive reservoir.

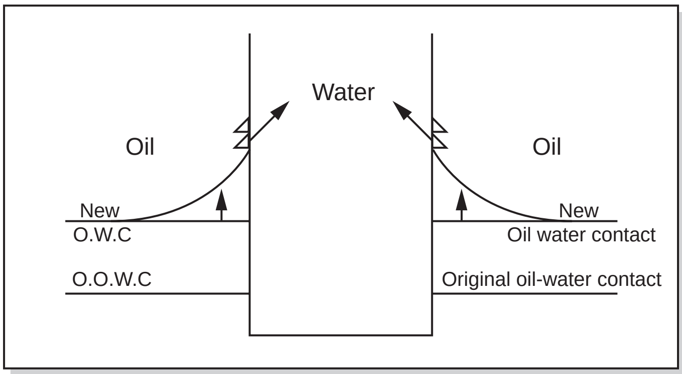


Figure 4
Water "coning" phenomena.

(ii) Induced Limitations on Well Performance

Limitations on the well performance can be induced within a reservoir at any stage of the well development i.e. from initial drilling through to production and workover. The range of mechanisms which induce limitations on well performance are referred to as ***formation damage*** and their effect is to reduce productivity by one or more of the following:

(1) reduce absolute permeability of the rock

(2) reduce the relative permeability of the system i.e. decrease in the primary mobile phase

(3) increase the mobile fluid viscosity.

The potential impact of these parameters can be seen from the equation developed by combining equations (1) and (3).

Formation damage which results in a reduction or limitation of well performance can occur because of a variety of reasons:

(1) plugging of the pore space by solids associated with drilling/completion fluids or injected fluids

(2) formation and deposition of inorganic scales due to mixing of incompatible fluids

(3) swelling or migration of clays

(4) compaction associated with reservoir depletion

(5) wettability reversal

(6) modification to fluid saturation - water blocking.

(7) emulsion formation due to reduced interfacial tension

Damage induced in the formation may reduce the productivity by an order of magnitude. However, it should be recognised that damage removal is usually not wholly effective, can be expensive and should thus preferably be avoided by the initial prevention of damage.

(c) Excessive Water or Gas Production

The production of excessive quantities of water or gas is to be avoided as it can radically reduce oil production rates and ultimate recovery (solution gas drive reservoirs) and, in addition, directly affects the production costs.

Excessive water production has the following disadvantages:

(1) reduction in oil fraction of produced fluids

(2) reduced total production rate because of greater hydrostatic head requirement in the tubing

(3) reduction in oil processing capacity

(4) increased volumes of water for disposal

(5) brings large volumes of potentially scale forming fluids into the wellbore

(6) increases the likelihood of sand destabilisation around the wellbore

Excessive gas production has the following disadvantages:

(1) reduction in oil fraction within the produced fluids

(2) reduces production rate because of increased frictional pressure loss

(3) reduction in processing capacity

(4) reduces reservoir capability to maintain pressure and hence production rate

(5) increased possibility of sand production due to erosion.

Such fluids enter the wellbore by either:

(1) communication established between the perforated interval and a fluid contact, e.g. G.O.C. or W.O.C.

(2) lateral migration towards wellbore via a high permeability layer, i.e. ***channelling***.

With increased pressure depletion in a reservoir with an active underlying aquifer, the rise in the W.O.C. may reach the lowest perforations or reach a height whereby the low pressure in the wellbore draws up the water from the aquifer, i.e. the process known as ***"coning"*** (Figure 4).

Similarly in a reservoir under "gas cap expansion" drive, with pressure depletion, the gas cap will expand volumetrically and as a consequence, the gas-oil contact G.O.C. will descend. Gas production could either occur by the G.O.C. descending to the top of the perforated internal or to such a height above the top perforations whereby it can be drawn in by the process of ***cusping*** (Figure 5).

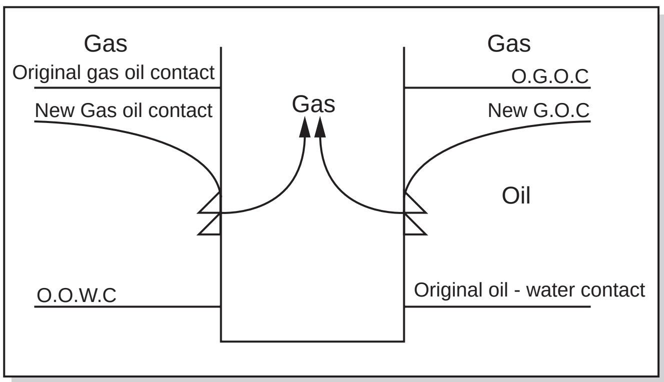


Figure 5
Gas "cusping" phenomena.

(d) Sand Production

Sand production can be a serious problem when it occurs in an oil or gas well. Some reservoirs naturally produce sand whilst others will only do so if certain production conditions exist. The break down of the formation or the production of sand can result in the following:

(1) casing damage due to formation slumping

(2) plugging and erosion of downhole and surface equipment

(3) sand disposal problems

Reservoirs which will produce appreciable quantities of sand from initiating production must be designed to exclude sand. Other reservoirs which may be susceptible to sand production depending on the production conditions may be operated such that they have a reduced tendency to produce sand, e.g. restricting the drawdown pressure/ production rate.

1.1.2 Reservoir Management Considerations

To ensure successful exploitation, a hydrocarbon reservoir must be continuously managed, as with any other resource. Earlier the concept of the reservoir as a dynamic entity was identified and this by necessity will reflect the need to adapt or change the envisaged plan for the development and production of the reservoir. There are several key areas which will cause a company to change its reservoir management policy.

(a) Drainage Policy

The model of the reservoir in terms of both structure and physical properties is based on data generated during the exploration, appraisal and development phases. The model is under continual revision, as will be the development plan. A key area under continual study will be the location of specific production and injection wells to optimise recovery and production rates.

Wherever possible, changes in target locations will be implemented as part of the normal development drilling plan. However, subsequent to production, it may be necessary to relocate the location within the reservoir to enhance recovery, e.g.:

(1) to improve sweep efficiency

(2) to improve the depletion in fault blocks

(3) to adjust the effective well spacing

(4) to optimise zonal depletion

Such changes may be effected by sidetracking, recompletion or a selective depletion strategy.

(b) Production /Injection Profile Modification

The efficiency of pressure maintenance on flooding projects which utilise gas or water injection, is heavily dependent upon the ability to control the migration of the injected fluid through the reservoir. Even in a homogeneous reservoir, the effects of gravity over-ride in the case of gas, or gravity under-ride in the case of water can be very serious. However, in large, productive, heterogeneous reservoirs such as occur in the North Sea, the effect on recovery economics and production costs can be drastic.

The need for profile correction may apply at either the production or injection wellbore. Further, it may be a function of the location of the perforated interval or be a natural consequence of the reservoir heterogeneity or layeral structure.

(c) Well Status

It may be necessary to change the status of specific wells from production to injection. This may be necessary because:

(1) an increased requirement for injection capacity due to a reduction in injection well availability, or changing reservoir conditions

(2) it may no longer be economic or technically feasible to change the location of an oil well in a reservoir, necessitated by excessive gas or water production. Instead of abandonment it may be preferable to change the well status from producer to injector.

The ease with which this can be accomplished will depend on the design of the completion.

1.2 Completion Associated Problems

Problems associated with the well completion account for the majority of workovers conducted on oil and gas wells. The necessity to workover the completion may be due to a problem in one of two major categories namely:

(1) equipment failure associated with the completion string

(2) the need to replace/change the completion due to vertical lift pressure loss considerations.

1.2.1 Completions Equipment Malfunctions or Failure

A typical completion string is complex and is often designed with an incomplete knowledge of the proposed operating conditions. Equipment may fail for a number of reasons, including:

FAILURE EVENT	OPERATIONAL CONSEQUENCES	CONCERN
Tubing failure • wall • coupling	Annulus communication	Well safety
Packer failure		
Seal failure on seal system		
Tubing hanger leak		
Xmas tree seal leakage	External communication	
Wellhead leakage	External or annulus communication	
Circulation sleeve seal failure	Annulus communication	
Failure of downhole hanger		
SSSV failure	Inability to isolate well Inability to land flow control devices	Well safety and loss of flow
Gas lift valve leakage	Annulus communication	Well control limitation
Gas life valve closure	Inability to kick off string	Operational limitation
Downhole pump failure	Failure to lift well	No production
Leaking seal assembly	Potential for mechanical failure of tubing	Well safety

Table 1
The nature and consequence of completion failure.

(1) effects of pressure

(2) effects of thermal stress

(3) applied and induced mechanical loadings can cause the tubing to part or unset packers. They can also be induced by temperature & pressure changes.

(4) internal corrosion failure due to O_2, CO_2, H_2S and acids. External casing corrosion can result from corrosive formation waters.

(5) erosion due to high rate flow and/or sand production.

It is also important to distinguish between the type of failure, namely:

(1) catastrophic failure implying a safety concern, e.g. tubing leak

(2) inability for well to produce, but with no immediate significant safety concerns.

The failure of equipment may dictate two courses of action (Figure 6):

(1) the removal and replacement of equipment

(2) the abandonment of the well in cases of extreme failure with untenable safety implications - this would obviously not be a first option.

(a) Equipment Removal/Replacement

The complexity of a completion string will define the potential for failure. However, the potential for string failure depends on both individual component reliability and that of the composite string based on component interaction. Reliability is defined as-

“The probability that a system will operate satisfactorily, for a specific period of time under specified conditions”.

Typical component failures may include:

- tubing failure - perforation of tubing wall or coupling failure.
- packer failure.
- failure of flow control devices such as S.S.S.V., circulation sleeves and wireline nipples.
- Xmas tree failure - leakage.
- tubing hanger failure at the wellhead.
- failure of gas lift mandrels and/or valves.
- downhole pump failure, etc.

The consequence of a component failure depends upon its integration with the string and its operation but may require either:

(1) removal and replacment of wireline retrievable devices or

(2) removal and replacement of the Xmas tree and partial or full removal and replacement of the completion string.

(b) Abandonment of Well Completions

In dire circumstances, as a last resort, it may be necessary to temporarily or permanently abandon the well completion. Permanent abandonment would be very much a last resort. Temporary abandonment of a well with a completion problem may be necessary because:

(1) The actual problem cannot be defined with reasonable certainty

(2) The capability to conduct the workover, may not be available.
This may be due to:-
(a) non-availability of spare completion equipment or workover equipment.
(b) more urgent alternatives for workover based on safety considerations.
(c) economically better justified alternatives.

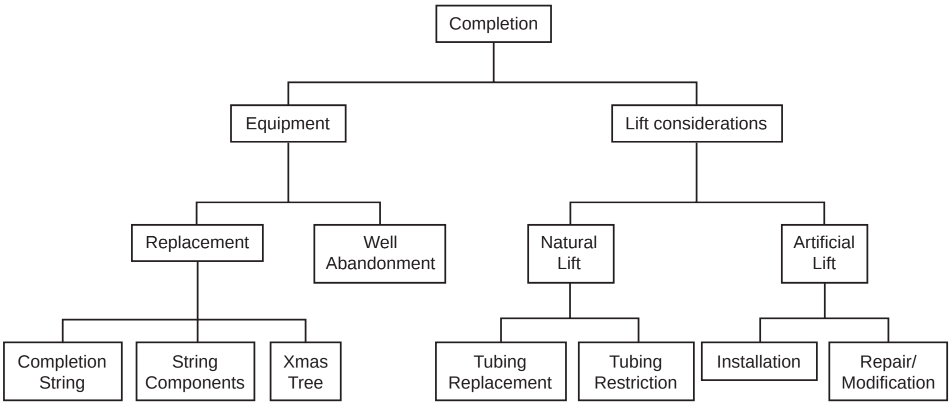


Figure 6 Completion related problems.

1.2.2 Vertical Life Performance Considerations (Figure 6)

Workovers designed to improve the vertical lift performance of a production well, account for a significant proportion of workovers, particularly in the North Sea. Workovers conducted in this area can be directed at:

(1) The improvement or restoration of the well performance on natural lift.

(2) The installation or replacement of artificial lift equipment.

(a) Natural Lift Wells

Production systems and in particular the reservoir component, can change with time. The change in reservoir production conditions can include:

(1) ***Reduction in reservoir pressure*** - decline in available pressure loss for production.

(2) ***Increase in water content*** - increased hydrostatic head and slippage - potential benefit could be derived by reduction in tubing diameter to decrease phase separation.

(3) ***Increase in gas production rate*** (e.g. solution gas drive reservoir) - increased frictional pressure drop - potential benefit derived from increasing tubing diameter.

In addition, there may be effects in the completion string generated by the production process:-

(1) tubing and nipple bore reduction due to wax and asphaltene deposition

(2) tubing plugging caused by scale deposition.

(b) Artifical Lift Wells (Figure 6)

The changing conditions in production wells as identified in 2.2.1 above may not be satisfactorily addressed by merely changing the tubing size. It may be necessary to:-

(1) Install artificial lift facilities such as gas lift or a pump system.

(2) Modify existing artificial lift facilities, e.g. increased volumetric capacity or modify valve spacing or capacity of gas lift system should the system not operate satisfactorily or require redesign. In addition, it may be necessary to repair equipment, e.g. replacement of gas lift valves which either do not open or close, or the replacement of downhole pump system.

1.3 Wellbore Problems (Figure 7)

Problems associated with the wellbore generally relate to the integrity of the casing and the associated wellhead equipment. Problems in this category normally relate to equipment failure rather than the need to modify or redesign.

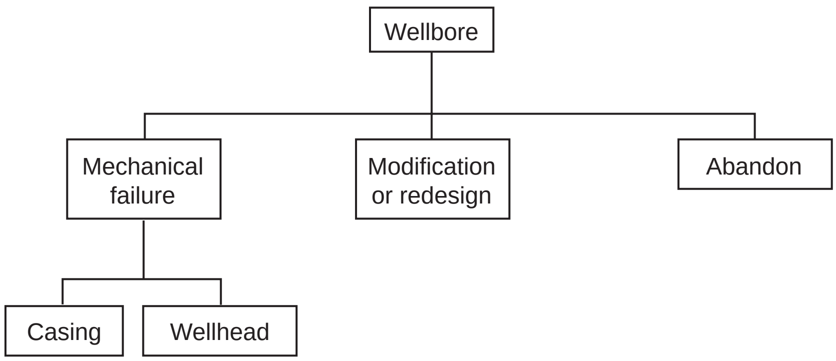


Figure 7
Wellbore related problems.

1.3.1 Mechanical Failure

Mechanical failure can occur due to:

(a) casing leakage
(b) casing hanger-seal failure
(c) casing spool leakage
(d) mechanical failure of the wellhead

(1) Casing leakage can occur due to:

(a) Internal corrosion due to packer/completion fluids, reservoir fluids and lift fluids, e.g. lift gas.

(b) External corrosion due to contact between reservoir fluids, e.g. formation water, and the casing. An effective cement sheath between the casing and the borehole is designed to prevent this. The cement sheath may not be effective because of:
(i) inefficient primary cementation
(ii) micro-annulus caused by variation in pressure
(iii) cement dissolution by water or acid

(c) Mechanical damage to the casing caused by operations inside the wellbore, e.g. milling, or by changes in the near wellbore matrix loadings e.g. slumping.

(2) Hanger failure may be associated with the method of installing the hanger and to subsequent casing strings. Damage to the hang-off-shoulder or to the actual seal system may have occurred. In addition seal decomposition may occur due to mechanical loading, the effects of pressure and temperature or chemical destruction.

(3) Casing spool leakage may also be associated with its installation or its subsequent response to operating conditions.

(4) Mechanical failure of the wellhead is less likely and if it occurs, it would primarily be assumed to be due to material defects or to improper design or specification.

1.3.2 Modification or Redesign

It may be necessary to redesign the wellbore, if the completion technique radically changes, e.g.

(1) A well completed with a production liner which demonstrates continuous fluid leakage, may need isolation at the liner top. This may be repairable by a tie-back packer, but in extreme cases may necessitate the installation of a tie-back liner to the surface.

(2) The installation of a gas lift or hydraulic pump system may not be feasible without redesign/isolation of the casing due to pressure burst limitations.

1.3.3 Abandonment

Problems which require corrective operations on the wellbore are more serious than tubing replacement workovers. The cost implications may be substantial and complete well abandonment or sidetracking from higher up in the well may be the preferred option. Finally, drilling a new well to the same or modified bottomhole location can also be considered.

2. RESPONSES TO WELL PROBLEMS

The method of responding to a well problem does, in fact, depend on the exact nature of the problem and the extent to which it can be defined. The type of response and alternatives can be discussed with respect to the three main areas of well problems, namely:

- Reservoir problems.
- Completion problems.
- Wellbore problems.

2.1 Reservoir Problems

2.1.1 Productivity/Injectivity Considerations

Which comprise:
(1) inefficient perforating productivity
(2) limitations in reservoir inflow performance into the well

(3) excessive water/gas production
(4) sand production

(1) Inefficient Perforating Productivity

When this problem is encountered in an existing well, the options for treating the problems are somewhat limited. First of all, we have to define the fraction of the perforations contributing to flow and, further, whether this flow distribution correlated with poroperm data (Figure 8).

If only a small proportion of the perforations are open we may have to clean up the perforations with either:
- a wash tool or by
- back surging

Alternatively, we may wish to use acid to clean up the perforations. This may not, however, be possible or desirable as it may have implications for the sand strength and the primary cement sheath.

If flow logging indicates a good distribution of perforations flowing, it may be necessary to re-perforate to increase the shot density. Again, the reduction in collapse resistance of the casing may be a consideration which might preclude this operation.

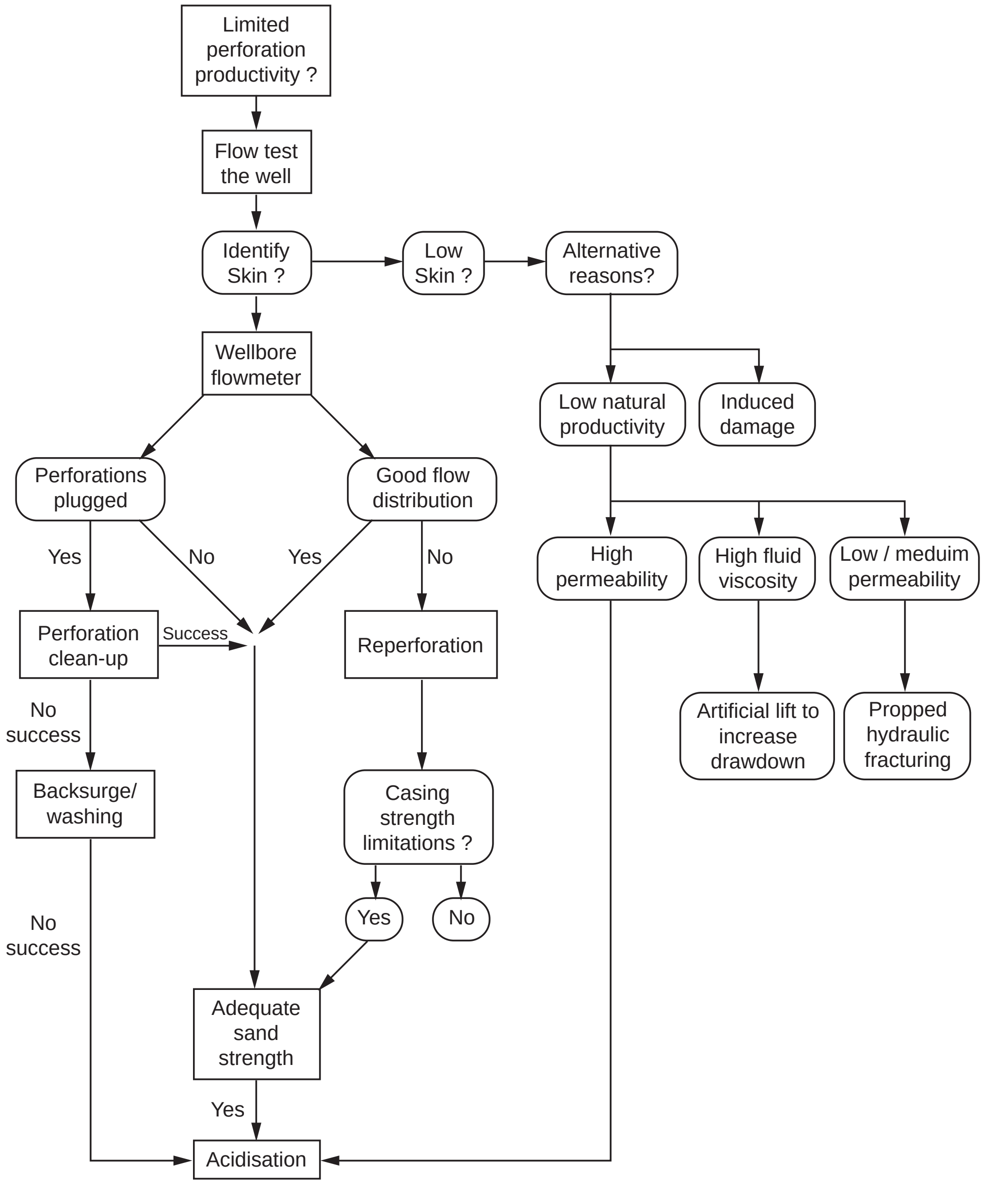


Figure 8
Options to remedy limited flow performance through perforations.

(2) Limitations in Reservoir Performance (Figure 9)

The productivity of the reservoir is controlled by:

Natural limitations such as:
- low permeability
- detrimental wettability phenomena
- high fluid viscosities

Induced limitations are the various forms of formation damage.

(a) Response to Natural Limitation in Productivity

Low Permeability:
A considerable number of reservoirs, in particular unfractured carbonate reservoirs, have good porosity but extremely poor pore space inter-connections. The techniques to improve performance in such reservoirs are:
- matrix acidisation
- acid fracturing (carbonate)
- hydraulic fracturing (sandstone)

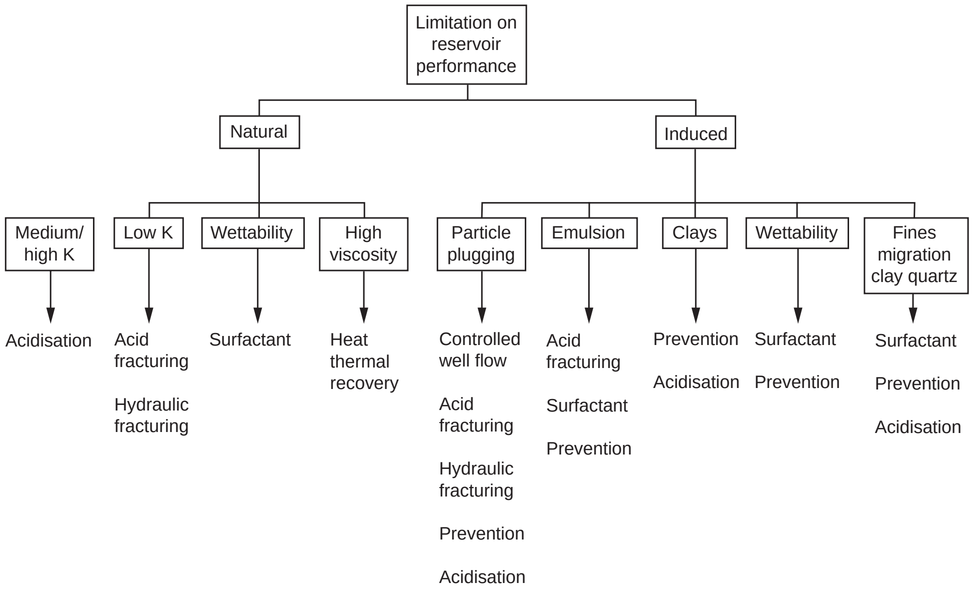


Figure 9
Options to remedy limited reservoir deliverability.

Fracturing can provide substantial increases in productivity whilst acidisation, being limited in its effect to near the wellbore, provides a limited improvement.

Detrimental Wettability Phenomena:
Most sandstones exhibit a wettability which ranges from mixed to strongly water wet, whilst carbonates can also be oil wet. The impact on well productivity if the rock is not water wet, can be very significant due to the relative permeability phenomenon.

The wettability of the rock can be changed by the use of surfactants; however, in view of the chemical complexity and the difficulties of ensuring satisfactory fluid contact within the pore space, the treatment is difficult and, if successful, is often not permanent.

Fluid Viscosity:
The principal means of improving the productivity of naturally high viscosity crude oils is to use a technique that increased the fluid temperature around the wellbore, i.e. ***thermal recovery techniques:***
- steam soak
- steam drive
- in-situ combustion

Like most EOR techniques, these need to be closely evaluated with respect to their economics for each specific potential application.

(b) Response to induced limitations in productivity, i.e. formation damage

As a general rule, formation damage should be prevented rather than create the necessity for its removal. The important issue is its indentification and prevention in future wells. This is possibly even more important than its removal in this well.

The response to formation damage mechanism: (Figure 9)

• particle plugging	- controlled drawdown production - dissolution by acid (HCL/HF) - by-passing by hydraulic fracturing
• clay swelling	- dissolution by acid (HF) - by-passing by hydraulic fracturing
• clay fines migration	- stabilisation by Al(OH) treatment - dissolution by HF or proprietary acids
• quartz fines migration	- dissolution by HF
• emulsions	- demulsifier treatment
• wettability reversal	- surfactant treatment

(c) Excessive Water of Gas Production

The available techniques to respond to water or gas ingress into the wellbore are:

- Install short (scab) liner across the perforations producing the unwanted fluid

- Squeeze-off with cement the necessary perforations and re-perforate higher (water influx) or lower (gas influx) as necessary.

- Plug back wellbore and lowest perforations with cement to isolate bottom water inflow

- Inject temporary plugging agent through desire perforations into the formation, i.e. lateral water ingress or downwards/lateral gas inflow.

Several fluid systems are available:
- polymers
- foam
- set a through tubing bridge plug TTBP above watered out perforations.

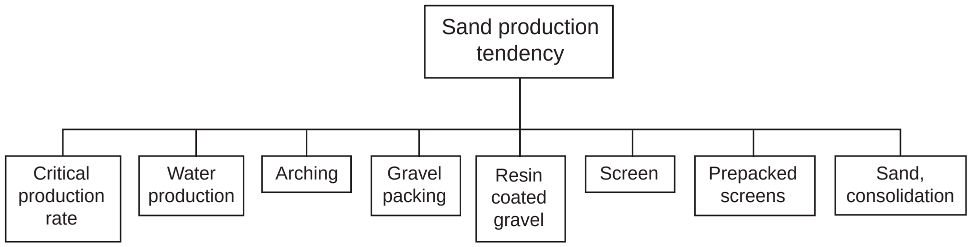


Figure 10
Options for sand control.

(d) Sand Production

Reservoirs which demonstrate a tendency to produce sand can be tackled in a number of ways (Figure 10).

The methods can be generally classified as those which attempt to restrict or eliminate sand migration towards the wellbore and those which attempt to exclude sand from entry to the production flow stream in the wellbore.

The available methods are listed below:

(a) Methods to restrict sand migration
• critical production rate - primarily applicable to gas wells.
• stabilised arch formation
• control water cuts

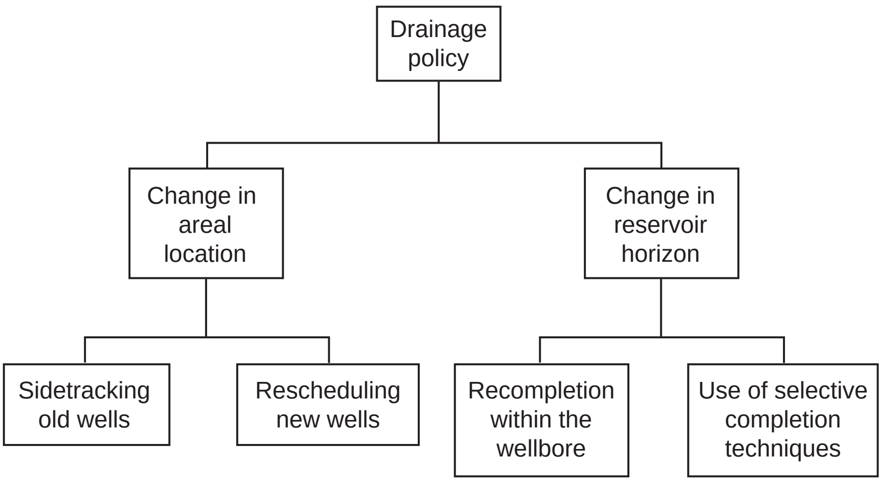


Figure 11
Options for changing the drainage location/policy.

(b) Sand exclusion technique
• use of screens or slotted lines
• gravel packing
• pre-coated screens
• resin coated gravel
• resin/plastic consideration

If possible, it is obviously less expensive to employ a technique which prevents sand destabilisation rather than the expense of a control technique.

2.1.2 Reservoir Management Problems

In this section, three types of well problem are identified.

(1) drainage policy
(2) alteration of production/injection profile
(3) change of well status

(1) Drainage Policy

An alteration in the drainage policy would normally require a repositioning of the well's drainage location areally or producing from a different reservoir horizon in the wellbore. A range of options are available (Figure 11).

Change in ***areal location*** might be required for:
(1) old wells - use sidetracking
(2) new wells - reschedule target location

Change in vertical location or reservoir horizon:
(1) Recompletion following reperforating
(2) Use of multizone selective completion

(2) Profile Modification for Injectors or Producers

Premature breakthrough of water or gas into a producer can be a function of the injection location but is normally more dependent on the reservoir heterogeneity. Profile modification can be accomplished by:

(1) Isolation of zone in the wellbore using:
(a) perforation squeeze
(b) through-tubing bridge plug
(c) plug back cement job
(d) isolate with packer

(2) Isolation within the reservoir:
(a) injection of polymers or foam
(b) use of diverter in injection wells

(3) Change of Well Status

A well which has largely gone over to excessive gas or water production may be converted for use as a fluid injector. It will require surface connection modifications but will be much simpler and less costly if no downhole modifications are required. The initial design of the completion might incorporate such a capability.

2.2 Problems Associated With The Completion

2.2.1 Equipment Considerations

(1) Replacement

Completion equipment normally leaves little option in response to its malfunction, since it will require either:

1. retrieval of the completion string from the well.
   Options:
   • retrieval of tubing and packer
   • retrieval of tubing from downhole hanger upwards
   • retrieval of tubing leaving (packer and tailpipe) in the well

2. replacement of items by wireline e.g. removal of chokes, regulators, etc., or the installation of SSVs

3. replacement of items by Through FlowLine techniques (T.F.L.)
   The precise response will depend on the specific completion design and the nature of the problem.

Completion strings can be designed with several philosophies:
- with built-in component redundancy - duplication of equipment
- maximum serviceability e.g. substantial wireline or coiled tubing servicing options, retrievable packers.
- maximum simplicity - i.e. eliminate as far as possible any complexity in the string design

The philosophies are very much in opposition to each other. It has been shown that a completion string which is mechanically simple has less reasons for failure and will generally outlast the more complex design.

Complex designs can be of specific use in several situations:

(a) A multi-zone selective completion is naturally mechanically more complex than a single completion, but provides the capability for more effective reservoir management.

(b) Completion designs can be designed to incorporate gas lift mandrels, which can be initially blanked off with dummies but brought into use when required.

(2) Well Abandonment

The well may be a candidate for abandonment if it is considered to have reached the end of its useful life. This could be due to either technical problems which cannot be corrected or that the well oil or gas production rate is no longer economic.

Important considerations in the planning of a well abandonment would be:

(1) Design of well isolation with cement plugs and bridge plugs. There is often a legal requirement for the placement and testing of plugs described in the host country Petroleum Legislation.

(2) Status of completion tubing - to be retrieved or retained in the well

2.2.2 Lift Considerations

This can be subdivided into two categories:

(a) natural lift problems

(b) artificial lift problems

(1) Natural Lift Problems

The precise flowrate obtained from a well depends on the

• Inflow performance relationship I.P.R.

• Tubing performance relationship T.P.R. (or V.L.P.)

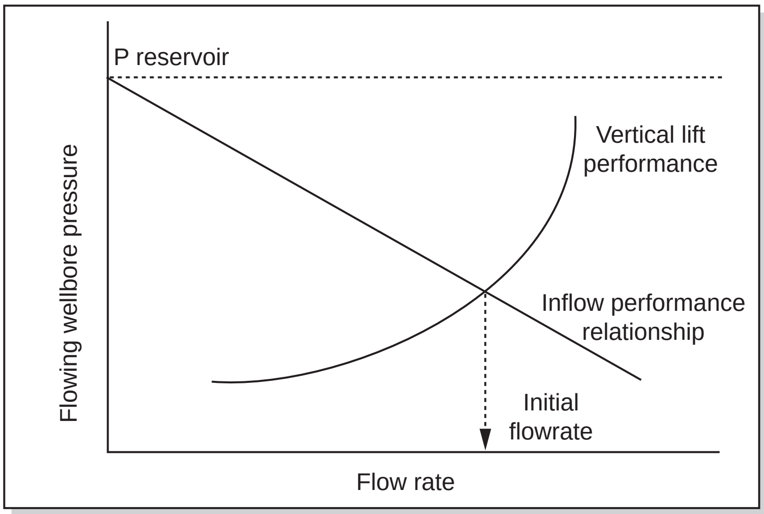


Figure 12
Ideal well performance graph.

Since reservoir pressure is finite, a well will only produce at a specific flowrate for a specific tubing head pressure (Figure 12). However, the production rate achievable with that completion can change if any one of the following occurs:

(1) declining reservoir pressure Figure 13

(2) increasing G.O.R. due to gas breakthrough Figure 14

(3) increasing W.O.R. due to water breakthrough Figure 15

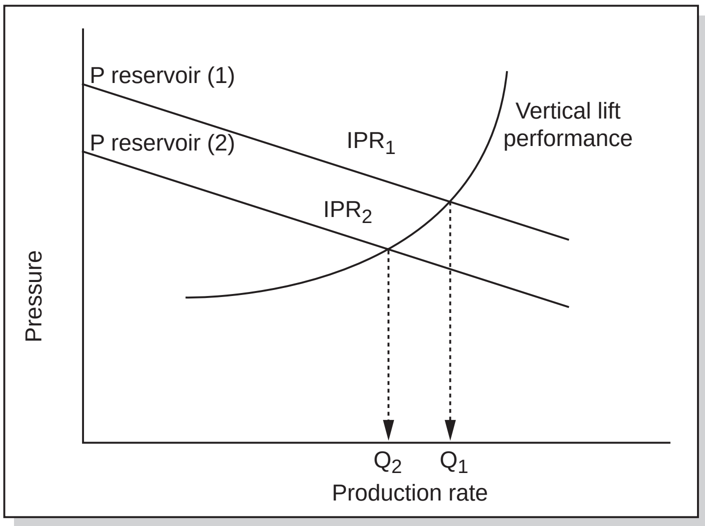


Figure 13
Effect of change in the IPR.

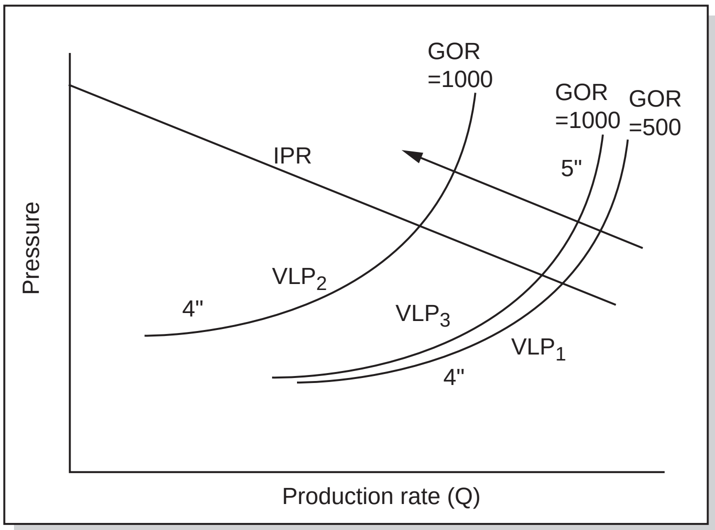


Figure 14
Effect of changing gas-oil ratio.

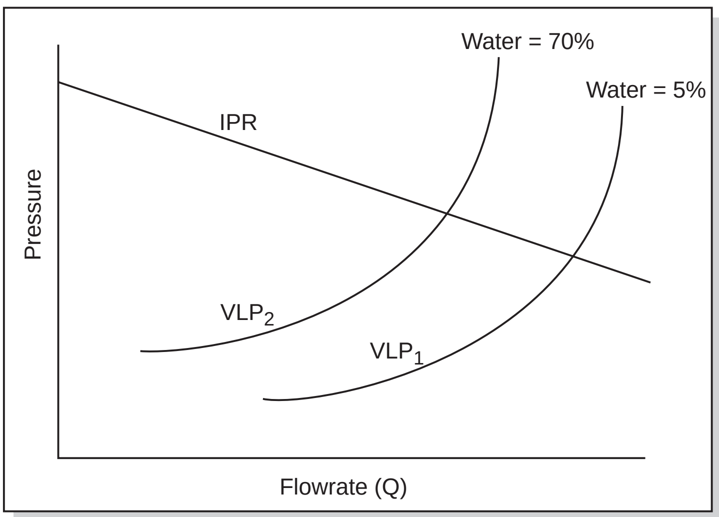


Figure 15
Effect of increasing water cut.

Declining reservoir pressure can only be counteracted by water or gas injection (from an external source) or re-injection of any unwanted fluids back into the reservoir.

Increasing G.O.R. will increase dramatically the pressure loss in the tubing. This can be counteracted by replacing the existing tubing with a large diameter tubing (Figure 14).

Increasing W.O.R. will normally be counteracted by trying to prevent water flow into the well bore by squeezing off perforations or attempting to conduct plugging treatments in the reservoir near the wellbore. The effect of increasing W.O.R. is to increase the hydrostatic head of the fluid column in the tubing and also to promote phase slippage. The hydrostatic head is not influenced by tubing diameter but in some cases slip can be reduced by using a smaller tubing size (Figure 16).

Restrictions can occur in the tubing string by either

- ***mechanical plugging***, e.g. inability to retrieve wireline plug, stuck logging tool, etc. Mechanical plugging will necessitate a wireline fishing job or, as a last resort, tubing retrieval

- ***Chemical plugging***

Inorganic & Organic scale can be removed by chemicals e.g. acid (if soluble), or mechanically by internal scraping using wireline or coiled tubing,

or subsequent to retrieval of the completion string.

(2) Artificial Lift

(a) Installation of Artificial Lift

The achievable pressure drop across the reservoir and completion controls the productivity of a well (Figure 12). If reservoir pressure declines, then it may be economic to employ a lift system to support natural productivity e.g.:

(1) Gas lift

(2) Downhole pumps can be :
    (a) hydraulic
    (b) electrical
    (c) jet

(1) Gas lift operates by providing increased gas to reduce the density of the fluids in the production tubing. This is accomplished via a series of mandrels which are a composite part of the installed completion string and a series of spaced-out, wireline replaceable valves. The following would be required if gas lift were to be installed (Figure 17):

(a) available gas for recycling

(b) good condition casing which will withstand the necessary injection pressure (burst criteria)

(c) any corrosive gases, e.g. CO_2 and H_2S, must be removed

(d) replacement of completion string

(2) Hydraulic pumping requires the injection of high pressure fluid into a pump located downhole. The fluid can either be supplied via the annulus, i.e. the casing or a concentric tubing, or down a second tubing string. If a concentric completion is required, this increases the complexity of the completion con figuration. The choice of fluid and the provision of the necessary processing capacity have both technical and economic implications. (Figure 18)

(3) Electrical submersible pumps require a specific completion design which will be considerably more complex than a standard single string natural lift completion because of the power supply cable. The availability of electrical power is essential. (Figure 18)

(4) Jet pumps would again require recompletion of the well and would necessitate considerations similar to those discussed above under hydraulic pumping. (Figure 18)

(b) Repair of Artificial Lift Systems

The repair of malfunctioning artificial lift systems can be complex. Gas lift is one of the easiest since wireline techniques can replace the valves (the primary cause of malfunctions). Pump systems require completion retrieval to service the system and this must be incorporated into the completion design.

2.3 Wellbore problems and repairs

(1) Mechanical Failure of the Wellbore

The casing and the wellhead system is fundamental to the integrity and security of the well.

Casing leakage can be approached by either:
- use of casing patches
- installation of a secondary concentric casing
- if a liner completion, a tie back can be installed

Wellhead leakage remediation requires wellhead removal and replacement. It is often complex.

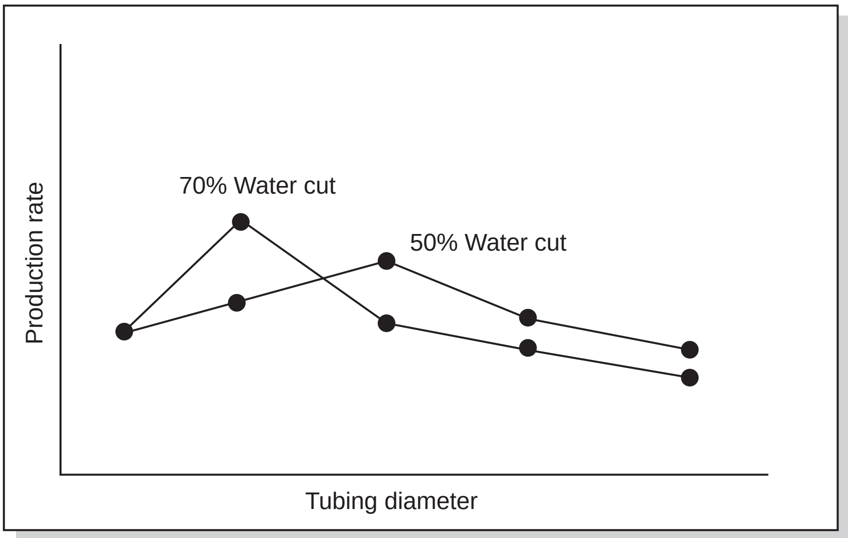


Figure 16
Impact on optimum tubing size of increasing water cut.

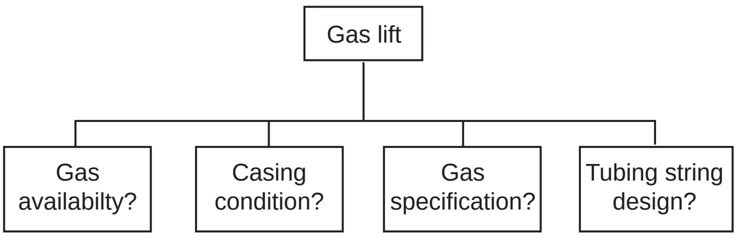


Figure 17
Options for implementing.

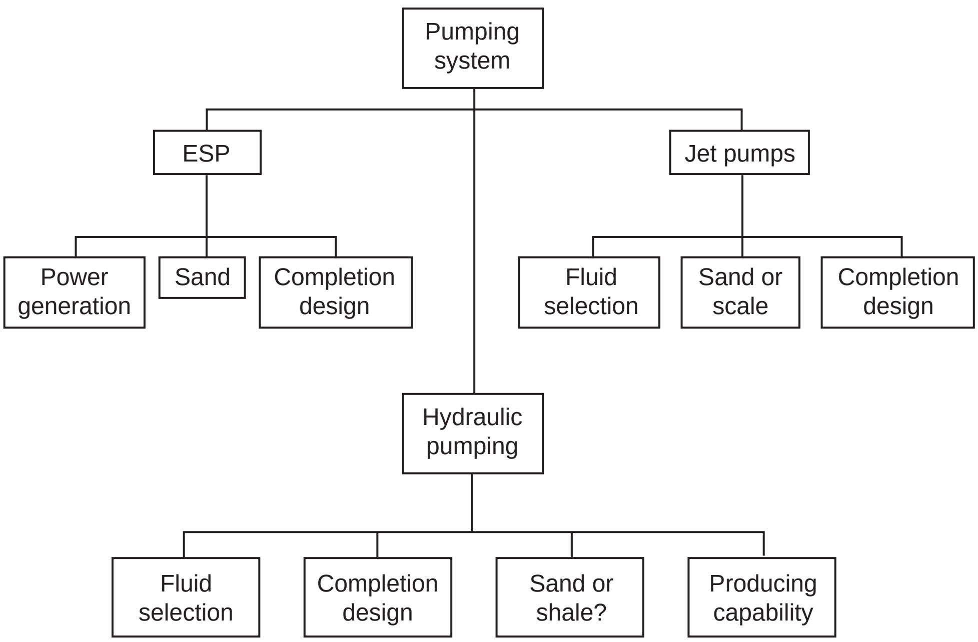


Figure 18
Considerations in implementing artificial lift using a pump.

CONTENTS

LEARNING OBJECTIVES:

Having worked through this chapter the Student will be able to:

- List the general requirements and objectives for abandoning a well.

- Describe the differences between an openhole and cased hole abandonment using cement plugs

- Describe the techniques used for recovery of equipment situated above the seabed for both fixed and floating drilling operations.

INTRODUCTION

The abandonment of an exploration or a production/injection well is required to ensure:

(a) That there is no hydraulic communication between the subsurface formation and the surface

(b) There is no communication or crossflow between formations downhole

Isolation requirements are governed by legislation guidelines/requirements. In principal a minimum of two mechanical barriers must exist between a subsurface formation and surface/seabed.

Typically the barriers comprise bridge plugs set in casing and these provide a platform on which a cement plug is placed. The bridge plugs, in themselves, are not acceptable as barriers.

Below the plugs it would normally be expected that formation isolation be provided by either:

(a) squeezing off perforations

(b) plugging back an open hole section of an exposed formation

There are three aspects to well abandonment:

(1) Provision of effective isolation between surface and any producing zones downhole i.e. **subsurface abandonment.**
(2) Recovery of equipment placed in the well, e.g. casing.
(3) To ensure that there is no obstruction left at the sea bed or surface, i.e. **seabed or surface abandonment**.

1 PLUG BACK ABANDONMENT

The most effective means of isolation is to set a cement plug downhole. The size of the cement plug to be placed will depend on the status of the well, i.e. length of open hole, formation fluids and formation of characteristics.

1.1 General recommendations for plug back

In general terms the following recommendations are made regarding cement plugs:

(1) The length of cement plug should be such that even allowing for a certain amount of contamination there is still sufficient to provide isolation, e.g. a cement plug of less than 100 ft. may not be adequate. Generally a plug length of 500 ft. minimum is recommended.

(2) Use either a neat or slightly accelerated cement to speed up the setting process. A retarded cement is not normally required since the displacement is made with a stinger.

(3) Consider using a fibreglass tubing for the work string in case the cement flash sets and there are difficulties in pulling back out of the cement plug after displacement.

(4) After the cement plug is considered to have hardened it is recommended that the top of the plug should be located. This is especially important in highly permeable or underpressured zones, which could give rise to lost circulation.

(5) If there are a number of areas of be plugged off across a long interval, requiring several cement plugs, it may be preferable to set bridge plugs by wireline and to then place a cement plug by wireline and to then place a cement plug on top of this using either a cement stinger or dump bailer. It should be realised that the bridge plug does not replace a cement plug; it merely reduces the length of cement plug required.

(6) To improve the quality of the cement plug it is recommended that a **balanced plug** be used with a water spacer ahead and behind, e.g. 10 bbls.

LENGTH OF CEMENT PLUG

As stated above, the length of plug will depend on the hole status.

Open hole

All productive zones in an open hole must be isolated by good quality cement. It is therefore advisable to use plugs of at least 500 ft. length with the top of the plug being at least 100 ft. above the top of the uppermost hydrocarbon or water-bearing zone. If the zone is productive then the plug should be at least 250 ft. above the top of the zone. **Figure 1**.

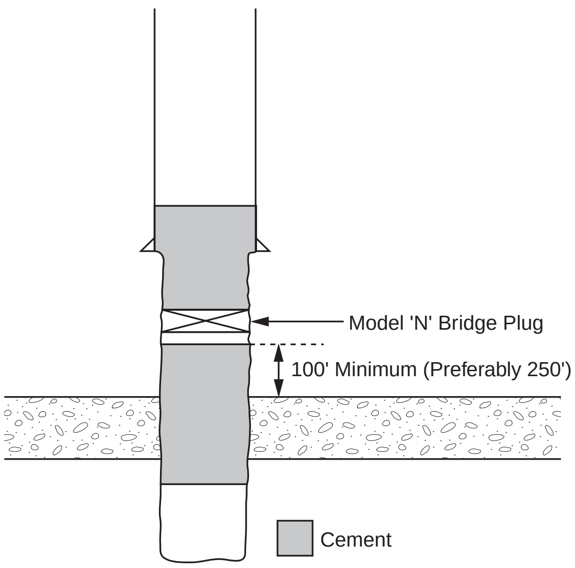


Figure 1

Open hole and casing shoe plug backs

Casing plug back

It is recommended that a cement plug be set across the shoe of the last casing string. Again it is recommended that the top of the plug be at least 100 ft. above the casing shoe. This plug should provide effective isolation of any leakage or deterioration in the bonding between formation and casing. **Figure 1**.

Perforated casing plug back (Figure 2)

This situation frequently occurs when plugging back an exploration well which has been tested. There are two options:

(a) The setting of a conventional plug, the top of which should be at least 250 ft. above the top perforation

(b) Setting a cement plug and then squeezing off the perforations. The squeeze operation can either be carried out with the B.O.P. shut or alternatively an R.T.T.S. packer can be run above the cement stinger. For the actual squeeze operation a guideline is to pull back to say 500 ft. above the T.T.O.C. and squeeze away the equivalent of 100 ft. column of cement. Care should be taken **not** to exceed the formation breakdown gradient. The amount which can be squeezed away will depend on the formation. However, the more cement that can be squeezed away the better will be the isolation even if a second cement plug has to be set.

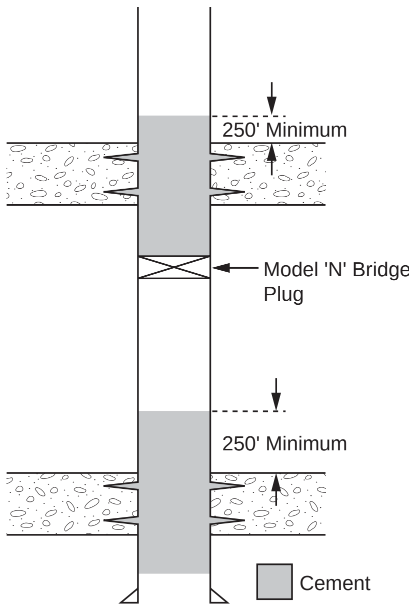


Figure 2
Plug backs in perforation

With plug back of perforated casing it is always necessary to ensure an adequate column of cement by running in and tagging the T.O.C. Additionally, it may be required to test the integrity of the cement seal by performing an **inflow test**. An inflow test is a means of exerting a drawdown on the formation by setting a packer and displacing the drill string to a fluid which is lighter than the drilling mud, e.g. sea water or diesel, and hence exerts a drawdown. Alternatively, the cement plug may be pressure tested against a closed B.O.P. However, it should be realised that both these tests can influence the cement integrity and in particular the inflow test can substantially damage the effectiveness of a cement squeeze or plug back.

2 SEABED ABANDONMENT

In this section the removal of equipment from or at the seabed will be discussed. In-general Government Legislation regarding seabed debris may cover the extent of recovery. This is particularly true for North Sea environments or other locations where deep-sea fishing is practised. For North Sea operations in U.K. waters the Secretary of State must consent to the abandonment of a well and in such cases all equipment including casing and wellheads must be removed to a minimum depth below the seabed. However, having plugged back the well with cement to provide isolation downhole there are two alternatives discussed below.

2.1 Recovery Of Equipment Above Seabed

In a large number of areas in the world (principally in waters around the lesser developed countries), wells can be abandoned leaving a minimum of equipment at the seabed.

To illustrate this type of abandonment, the Cameron mud line suspension equipment will be considered. The M.L.S. system allows the casing string weights to be hung off at seabed and each casing string can have an extension to a wellhead system above sea level. Each extension is attached to a casing hanger by a running tool which has a coarse left hand thread. To abandon such a well, cement plugs will be sent downhole as discussed previously. The B.O.P. stack can then be removed and the 9 5/8” x 7” casing spool removed. The 7” extension string can then be backed off at the running tool and raised to the surface. Similarly by sequentially removing the next casing spool and casing extensions the 9 5/8”, 13 3/8” and 20” extension strings can be retrieved. The procedure is almost the reverse of the installation sequence for the wellhead. Finally the 30” extension string can be backed off. (N.B. to back off the extension string it is necessary to apply tension and rotate above the hanger. To apply tension a casing spear is lowered on drill pipe inside the casing, set by R.H. rotation and tension applied).

With this type of abandonment the 9 5/8” hanger will project a few feet above the seabed and in such instances would obviously be a nuisance to marine operations.

2.2 Recovery Of Equipment To A Specific Point Below The Seabed

It may be necessary to recover from the well seabed equipment and casing strings for one of the following reasons:

(a) **Legal requirements**
As indicated above it may be necessary to remove all guide bases, casing, etc., protruding above seabed. This is required so that no obstruction or impediment to fishing or shipping remains on the seabed.

(b) **Economic requirements**
If casing strings have to be cut and recovered below the seabed it may be desirable to cut some of the casings deeper and recover a greater length of it. This may apply to exploration wells where the casing has not been installed for a long period and where it is not cemented up its entire length.

The type of equipment depends on the operating environment.

2.2.1 Fixed Drilling Locations

In situations where there is no relative motion of the casing and the rig, e.g. jack ups and fixed platforms, a conventional internal pipe either can be used, e.g. Bowen internal cutter (which is available to cut casing up to 20”). This type of cutter, Figures 3, 4, and 5, is run inside casing.

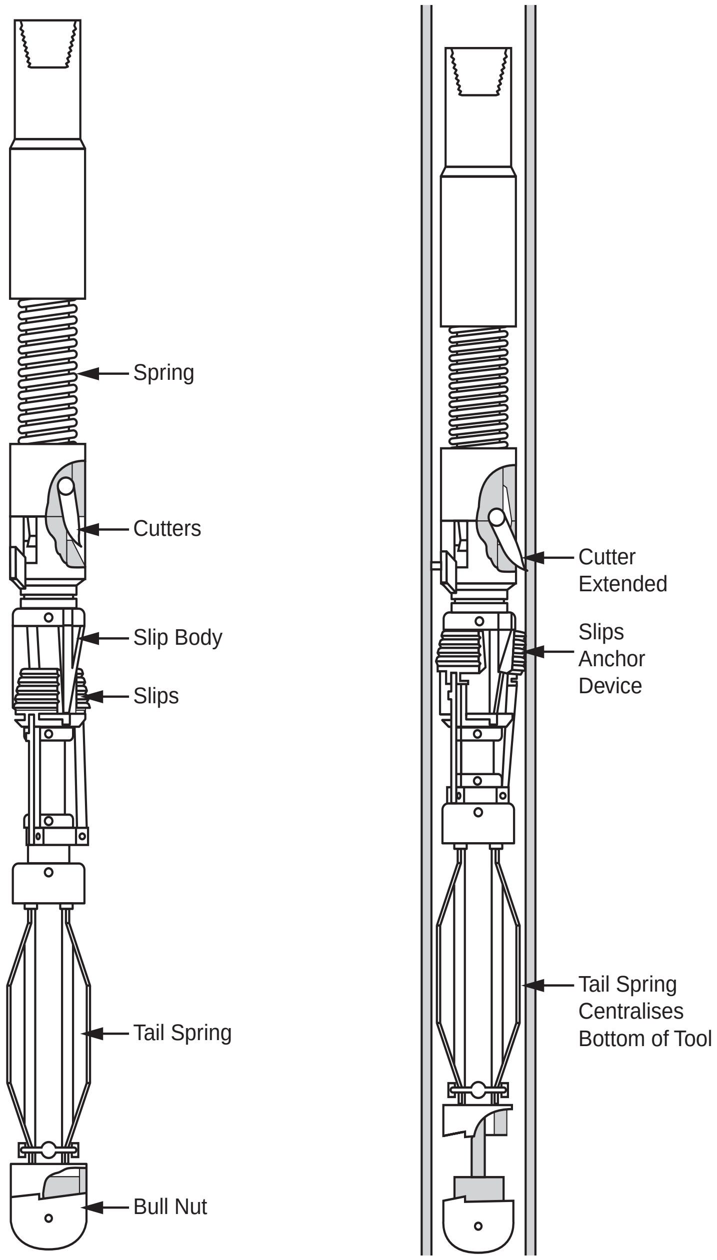


Figure 3 (left)
Internal Casing Cutter in Closed Position

Figure 4 (right)
Internal Casing Cutter in Cutting Position

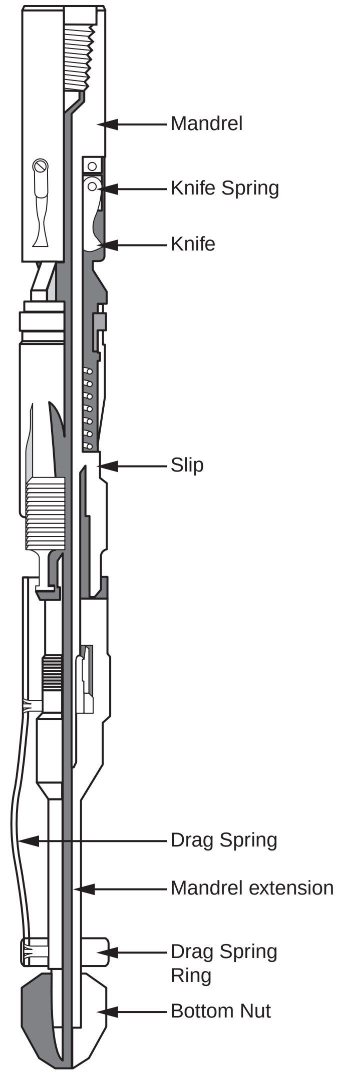


Figure 5
Bowen Internal Casing Cutter with Drag Spring

At the setting depth, the drag spring assembly permits setting of the slip and cone assembly, which fixes the cutter at that location. The cutting knives which are hard faced or ground steel are pushed out on to the inside wall of the casing by the throat blocks using weight applied to the string. Rotation then provides the cutting action.

Using this method the smallest casing string can be cut and retrieved with its hanger. The remaining casing strings are retrieved consecutively in this way. The method assumes easy retrieval of the hanger from the wellhead.

An alternative design utilises wiper blocks to provide the drag for setting the tool against the casing wall (Figure 6).

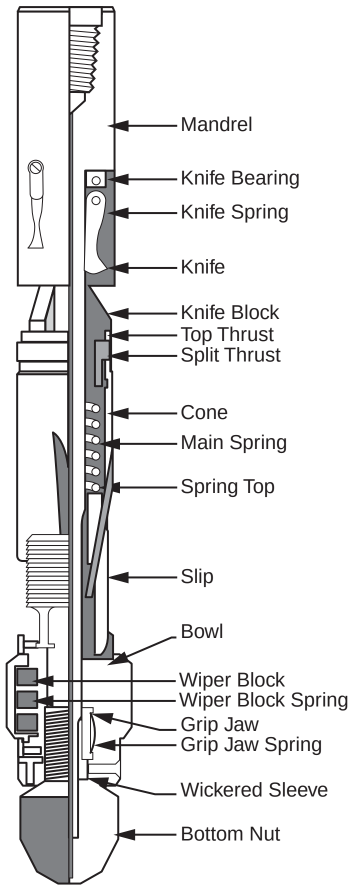


Figure 6
Bowen Internal Casing with Wiper Block

2.2.2 Floating Locations

For cutting casing from floating rigs a **Marine Casing Cutter** is used. This cutter has three arms, which are hydraulically operated. The action of pump pressure on a piston inside the tool pushes the arms out on to the casing inside wall. Rotation of the drill string then causes the cutting action. The effectiveness of the cutting action is influenced by the pump pressure and rotary speed.

One difficulty in floating operations is maintaining the cutters at a preset depth despite the influence of heave. This is accomplished by using a **Marine Swivel**, which is located in the string and is landed off inside the wellhead at a predetermined position. A long stroke bumper sub located above the swivel compensates for the heave of the rig.

It may be necessary after recovering the smaller casing strings, to cut completely through the remaining casing strings and recover these as a complete unit with their wellheads. In this situation the cutting depth would be limited to a short distance below the seabed.

Advanced Well Systems 13

CONTENTS

LEARNING OBJECTIVES:

Having worked through this chapter the Student will be able to:

1. INTRODUCTION

Exploration and production of oil and gas have been transformed over the past ten years by extensive developments in well systems and technology. Drilling and completion technology has made possible new well shapes that have increased the efficiency of oil production. The definition of advanced wells encompasses a range of new technologies that may be applied individually or in combination:

- Horizontal wells
- Extended or ultra reach wells
- Multi-lateral wells
- Intelligent (“smart”) wells
- Coiled tubing drilling/reeled completions
- Underbalanced operations
- Multiply fractured horizontal wells

This course is about the application of advanced wells to enhance the exploitation of oil and gas reservoirs. Such wells are also known as “unconventional” wells or, in the case of complex trajectories, the term “designer” well is sometimes used. The motivation for using this technology is to:

- Access otherwise inaccessible reserves
- Improve recovery factor/sweep efficiency
- Increase flow rates
- Enhance profitability per dollar invested

Advanced wells are characterised by more demanding application of established methods in production geoscience and petroleum engineering:

- The well configuration is more complex requiring an accurate reservoir description with adequate data

- Costs have to be well understood and a robust economic analysis must be carried out

- The full life cycle with possible recompletions, workovers and stimulation must be considered in advance

- A thorough assessment of risks with consequent contingency planning is essential

Advanced wells can bring commercial benefits and allow cost effective data acquisition to be carried out. The commercial benefits occur through one or more of the following:

- Reduced capital expenditure per barrel
- Reduced operating expenditure per barrel
- Accelerated reserve steam

The data acquisition occurs through probing of the lateral limits of the reservoir using logging while drilling.

Difficulties and challenges that arise in advanced well applications are:

- In conjunction with improved benefits, the potential risks are greater
- Increased complexity requires more rigorous validation and design
- Operational constraints are greater
- Concentration on fewer wells in the development increases detrimental impact of losing one well

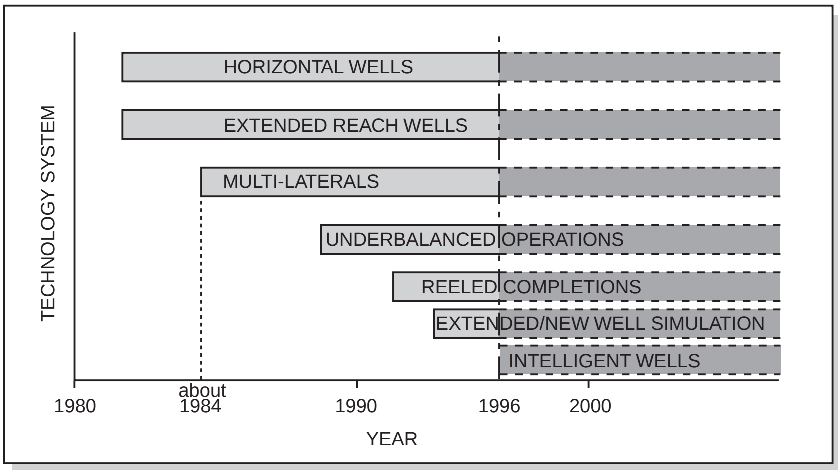


Figure 1 Development chronologically of advanced wells

The time frame begins twenty years ago when horizontal wells became a reliable option in field development. At the same time the limits reachable by extended reach wells were being extended.

Some business drivers that have boosted advanced well technology are:

- Low oil prices
- Competitive need for cost reduction
- Accelerated production and cash flow
- Increasing recovery using existing infrastructure

Many advanced well types were prototyped in the Soviet Union as early as the 1950s. They were then brought to commerciality in North America and elsewhere in the 1980s.

To get the maximum benefit from advanced well technology we need a rigorous planning process that brings together the appropriate level of knowledge and experience and enjoys the full support of senior management. A good database containing reservoir and well details in the area around the proposed well is the foundation of this planning process. The plan should not only focus on drilling, completion and early production but should cover the full life cycle of the well through to abandonment and should address all reasonable contingencies in this period. The design principles should be simple and clear to all participants and practical to implement.

Brief definitions of the six components of advanced well technology will now be presented with more detail provided in subsequent sections.

1.1 Horizontal Wells

Long lateral sections horizontal or parallel to bedding plane.

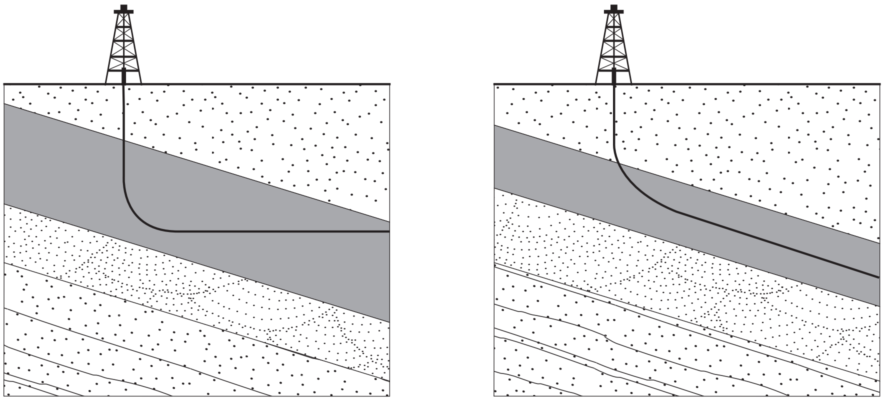


Figure 2
Alternative "horizontal well" configurations

1.2 Extended Reach Wells

Drilling technology now allows lateral research to be more than 10 times the vertical depth of the reservoir for moderate depth reservoirs. Although drillable, there are completion and intervention problems to be overcome. Generally the $/barrel cost will be higher than for a conventional, shorter reach well.

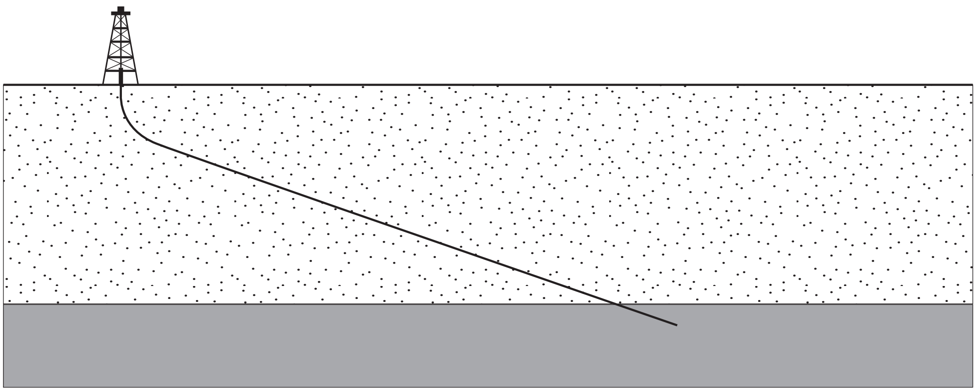


Figure 3
ERD Well

1.3 Multi-lateral Wells

Wells with two or more branches joined to a main or mother well bore. An example of a dual-opposed configuration.

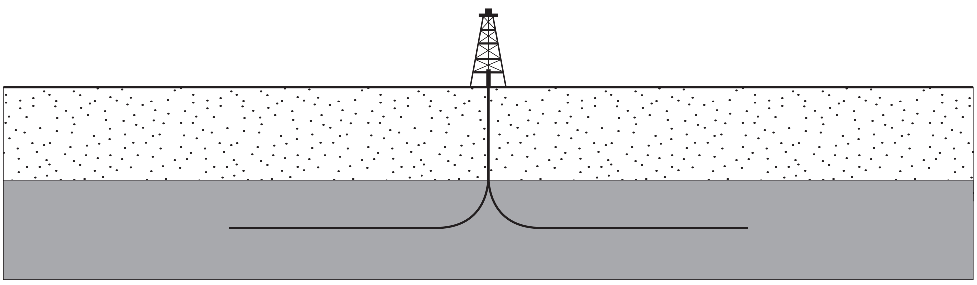


Figure 4
Dual opposed multilateral

1.4 Intelligent ("Smart") Wells

Smart wells are horizontal wells that have downhole instrumentation that can not only measure downhole parameters such as flow rate, fluid composition and pressure, but they can also have downhole flow control devices that can regulate and optimise the flow of hydrocarbons to surface.

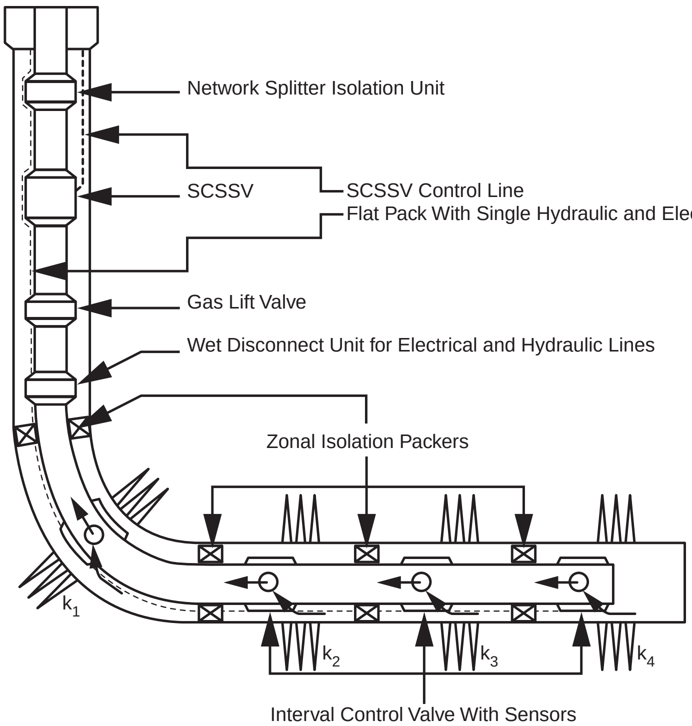


Figure 5
An "Intelligent Well" completion

1.5 Coiled Tubing Drilling

Coiled tubing drilling uses continuous pipe spooled onto a reel. The drill-bit, powered by a downhole mud motor can often be run through an existing completion, which avoids the cost of a full workover. The horizontal section that can be achieved is currently of smaller diameter and shorter than wells drilled with conventional equipment.

1.6 Underbalanced Drilling

Use of lighter mud can lead to the bottom hole pressure being less than formation pressure. Such underbalanced conditions can be safe provided adequate pressure control and fluid handling facilities are available at surface. The advantages are reduced formation damage and increased rate of penetration. Although underbalanced drilling can be carried out using conventional drill pipe with a drilling rig it is quite common nowadays to combine coiled tubing drilling with underbalanced drilling.

1.7 Multiple Fractured Horizontal Wells

In a low permeability formation where vertical wells are usually fractured it may be necessary to also hydraulically fracture horizontal wells. The orientation of the fracture depends on the principal stress direction. If the well has been drilled approximately along the principal stress direction then the fracture will be along this direction. If the well direction is approximately perpendicular to the principal stress direction then the fracture planes will be perpendicular to the well direction and many fractures will be required to get good drainage volume in the reservoir.

2. HORIZONTAL WELL BASICS

Introduction

In this chapter we introduce the basics of drilling and completing a horizontal well. We discuss well trajectory and geosteering and examine reservoir flow regimes and drainage areas. In general, this concerns high rate wells (>1000 b/d, or 160 m^3/d) drilled in deep reservoirs (>2000m TVD below surface) i.e. rates which are required offshore to be commercial. Usually such wells use medium or long radius build section; rather than the short radius build that is used for short lateral reach, small diameter wells applied to shallow reservoirs.

Drilling and completion of horizontal wells

In horizontal wells, the production casing (9 5/8" for example) is usually set just above or just within the reservoir at a fairly high angle (>70˚ say). In some cases a pilot hole (8 1/2" for example) may be drilled from that point, straight out of the casing through the reservoir. When the pilot hole has been evaluated and plugged back (or in the case where the pilot hole is ommitted), the well is turned to horizontal and drilled through the reservoir to the planned length. Depending on the choice of well completion the reservoir-wellbore interface (e.g. slotted liner) will be installed at this time.

2.1 Horizontal Well Trajectory and Build Radii

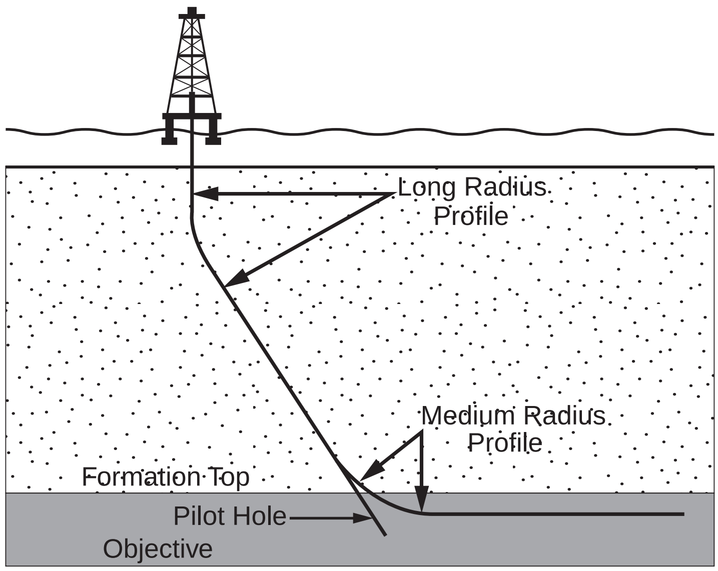


Figure 6
Build profiles

The trajectory from surface to an entry point close to the reservoir is drilled using "conventional" drilling technology with a long radius (1˚-6˚/100 feet) build-up section to get the correct "sail" angle. The build-up into the reservoir is usually medium radius (8˚-20˚/100 feet). The entry point into the reservoir is called the "heel" and the far end of the well away is called the "toe". In cases where there is a fluid contact above or below the well, the well is usually drilled parallel to that contact and the vertical distance to that contact is called the "standoff". Directional control is to between 1.0 and 1.5m in the vertical direction. The horizontal section control is to between 1.0 and 1.5m in the vertical direction. The horizontal section can be in excess of 2000m, the limit usually coming from reservoir requirements, completion or well access considerations, but not usually from drilling. Combined with extended reach, the toe of the well can be more than 10,000 meters horizontally from the surface well head. In some areas e.g. Qatar, horizontal sections exceed 6 km.

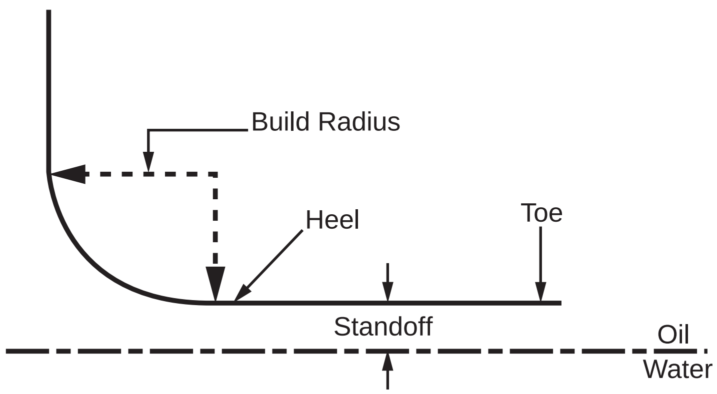


Figure 7
Horizontal well definitions

Hole Type	Build Radius for 90° turn (ft/m)
Long Radius	1,000-2,000 / 300-600
Medium Radius	300-800 / 100-250
Short Radius	30-200 / 10-60
Ultrashort Radius	1 – 6 / 0.3 - 2

Table 1
Build radii

2.3 Geosteering

The capability to drill and complete a horizontal well as discussed above is impressive but its success depends on being at the correct depth in the reservoir. Since the horizontal well encounters directly the lateral heterogeneity of the reservoir it must be steered in response to the formations and fluids penetrated. This steering process, by which a well trajectory is actively adjusted using real-time information, is known as geosteering. Its effectiveness is measured by how closely the well reaches its intended geological and hydrocarbon target. The real-time information can come from:

- microfossils to identify stratigraphic horizons
- cuttings to identify different marker lithologies and to differentiate reservoir from non-reservoir
- gas and oil shows to identify fluid contacts
- LWD tools to identify facies and lithology changes
- Dedicated geosteering tools

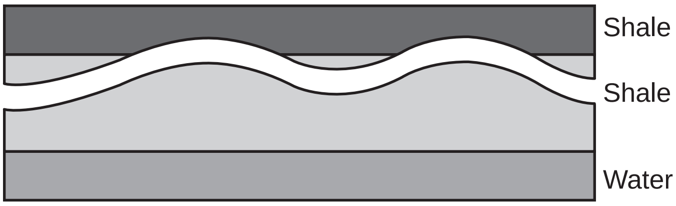


Figure 8
Geosteering on a shale zone

The main applications of geosteering are:

Horizontal steering on a fluid contact

Horizontal wells in oil rims are subject to severe gas cresting if any part of the well is close to the gas-oil contact. To make optimum use of such a well it may have to be positioned just above the oil-water contact. This can be done with resistivity tools when the water and oil zones have a large resistivity contrast.

Steering close to a shale layer

It is often desirable to steer the well just under the shale that seals the reservoir using resistivity, gamma ray or porosity tools depending on conditions.

Steering in a high permeability sand

Capillary forces usually mean that high permeability sands have lower water saturation than low permeability sands so there exists a resistivity contrast between these sands. A resistivity tool can be used to steer the wellbore through the high permeability sand.

An example of geosteering in thin sand is shown in Figure 9:

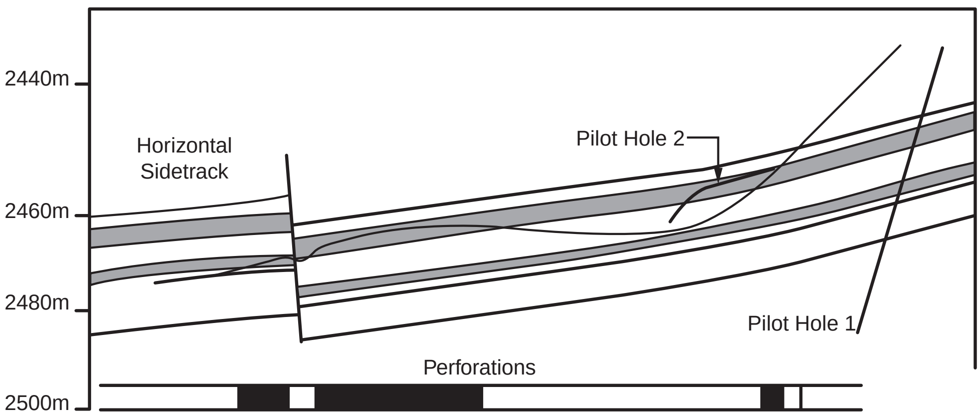


Figure 9
Geosteering example

2.4 Horizontal Well Completion

Some of the factors influencing well design are:

- Cost
- Sand control requirements
- Zonal isolation and selectivity required for shut-off and stimulation operations
- Operational constraints affecting access

At this point it is only necessary to summarise the generic types of completion with their advantages and disadvantages:

System	Advantages	Disadvantages
Barefoot completions	- lowest cost - largest internal diameter	- risk of hole collapse - difficult to abandon - no sand control
Open-hole liner completions	- avoids complete collapse - may provide sand control	- isolation and selectivity still problematic - difficult to abandon
Cased-hole liner completions	- facilitates zonal isolation - allows hydraulic fracturing treatments - can be completed as a “smart” well	- higher cost - difficult to achieve a good cement bond

Table 2
Completion options

Sketches of the three types of completions are shown Figure 10:

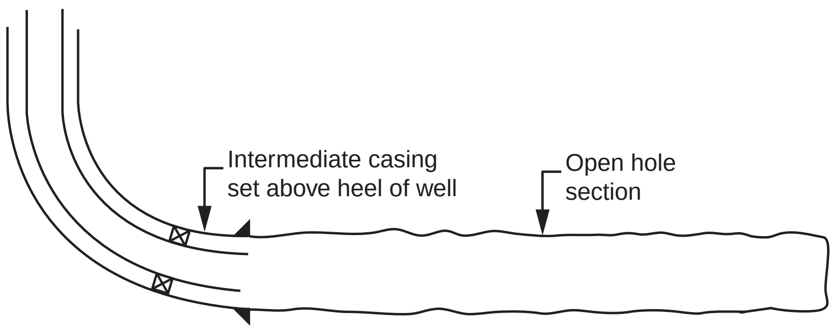


Figure 10
(a) Open hole completion of the lateral

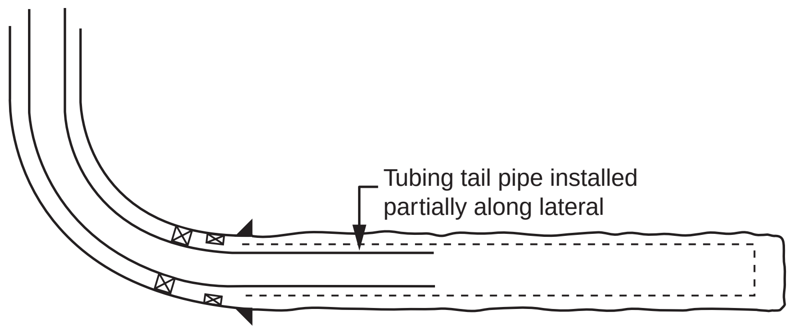


Figure 10
(b) Tailpipe accessing the lateral of an open hole liner completion

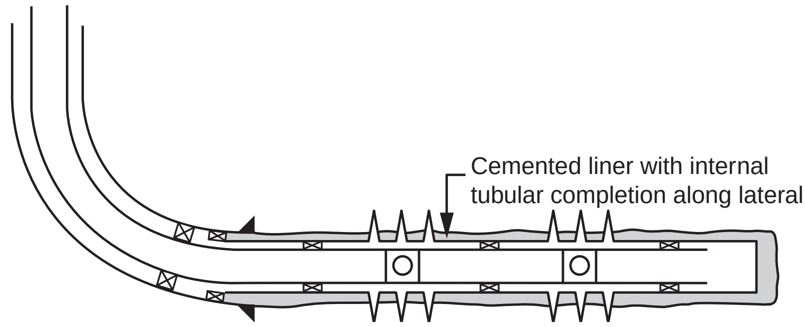


Figure 10
(c) Selective completion along the lateral

2.5 Flow Regimes

Vertical wells fully perforated across the reservoir section have a simple radial flow regime, with no vertical flow within the reservoir. For horizontal wells it is essential that fluid flows vertically in order to get to the level of the horizontal well (Figure 11). If vertical flow is not possible, (i.e. vertical permeability is zero) then the well will only drain oil from a horizontal layer whose thickness is the well diameter. In general over time a horizontal well has as a sequence of near wellbore, radial, linear, pseudo radial and hemispherical flow regimes.

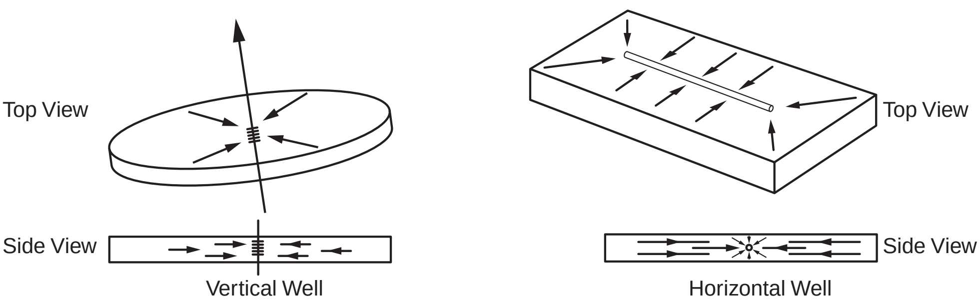


Figure 11
Reservoir flow regimes

2.6 Reservoir Drainage Area

Since the length of horizontal well that can be drilled is comparable to the well spacing between vertical wells, it is reasonable to hope that a horizontal well could have the same drainage area/volume as several vertical wells. Experience to date shows that in a field development plan a horizontal well can typically replace between two and four vertical wells (figure 12). This expectation needs to be confirmed by experience over the long term for a given field, as it does depend upon the individual structure and continuity. It can only be definitively known at the time of field abandonment.

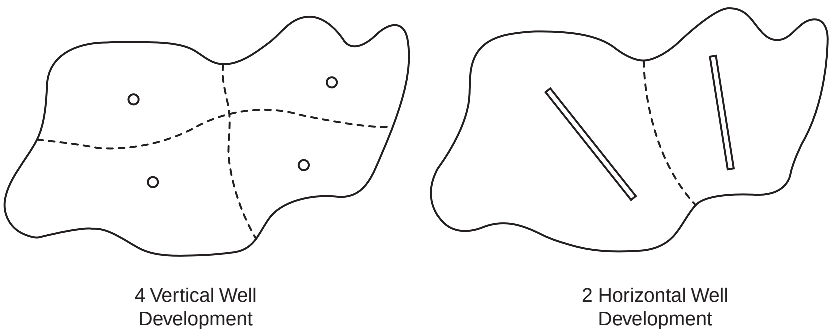


Figure 12
Horizontal and Vertical well drainage areas compared

2.7 Productivity Improvement Factor

In this chapter well productivity index *J* is defined as:

$$J = \frac{Q_{hc}}{(P_{av} - p_{wf})}$$

Where

Q_{hc}	=	Hydrocarbon Production Rate at Standard Conditions
P_{av}	=	Average reservoir pressure in drainage volume of well
P_{wf}	=	Bottomhole flowing pressure, measured at same datum level as p_{av}

The expression in the denominator of the above equation, $(P_{av} - P_{wf})$ is usually referred to as the drawdown.

Productivity Improvement Factor (PIF) is then defined as the ratio of horizontal well productivity index (J_H) to vertical well productivity index (J_V):

$$PIF = \frac{J_H}{J_V}$$

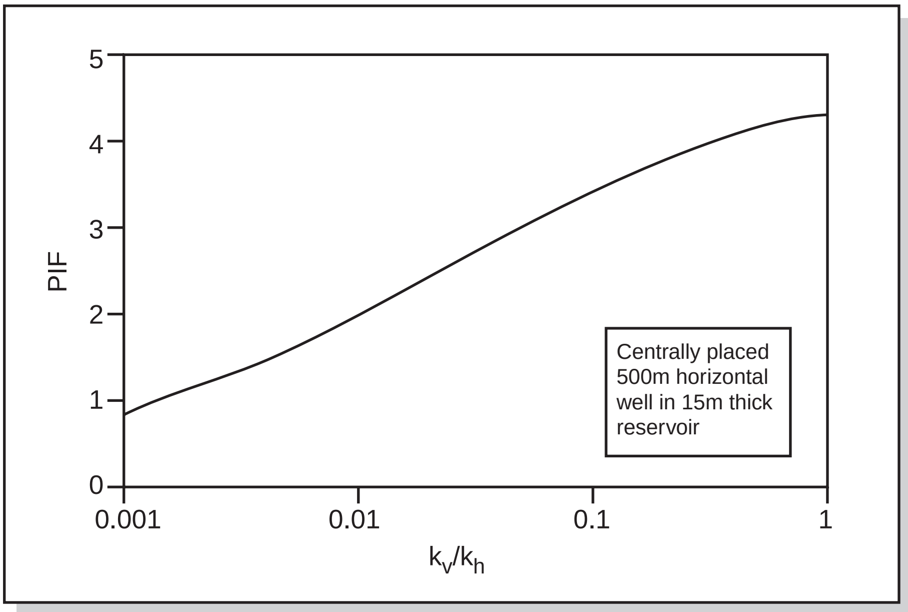


Figure 13
PIF for a horizontal well as a function of k_v/k_h

where both are measured at the same time in nearby wells assuming that production has stabilized in both wells. The PIF is one useful measure of the benefit of horizontal wells. For example it is a good way of looking at the sensitivity to k_V/k_h. Figure 13 shows a case where a 500m long well is placed in a 15m thick reservoir. At the low end of the range the horizontal well performs more poorly than a vertical well while for $k_V/k_h = 1$ the horizontal well productivity is 4.3 times better than a vertical well.

2.8 Benefits of Horizontal Wells

The benefits of horizontal wells are five-fold:

1. Increased exposure to the reservoir
2. Connection of laterally discontinuous features
3. Changing the geometry of drainage
4. Extending field appraisal laterally
5. Reduction in drilling costs and risks

These are now discussed in more detail.

2.8.1 Increased Exposure to the Reservoir

The increase in reservoir exposure benefits in two ways. In the short term the production rate is higher and in the long term the cumulative production from a horizontal well is greater giving more reserves per well. Thus, the number of wells required to achieve a given plateau production rate and recovery factor will be less.

Dennis Beliveau of Shell Canada conducted a review (SPE 30745) of more than 1000 horizontal wells comparing their hydrocarbon production performance to nearby vertical wells. Beliveau plotted the distribution of productivity improvement factors (PIF's) and found a lognormal distribution and deduced that:

1. Horizontal wells in conventional reservoirs show a mode, or “most likely”, PIF = 2; a median, or “50/50”, PIF = 3 and a mean, or “average”, PIF = 4
2. Higher PIF are observed for heavy oil horizontal wells and horizontal wells in heavily fractured fields. The common rule of thumb is that a horizontal well is likely to provide 3-5 times more production than a vertical well. This is true on average but there is a large spread and around 25% of horizontal wells are considered “disappointing”. It is necessary to make “many trials” or, in other words, drill many wells to achieve the “3-5 times” objective.

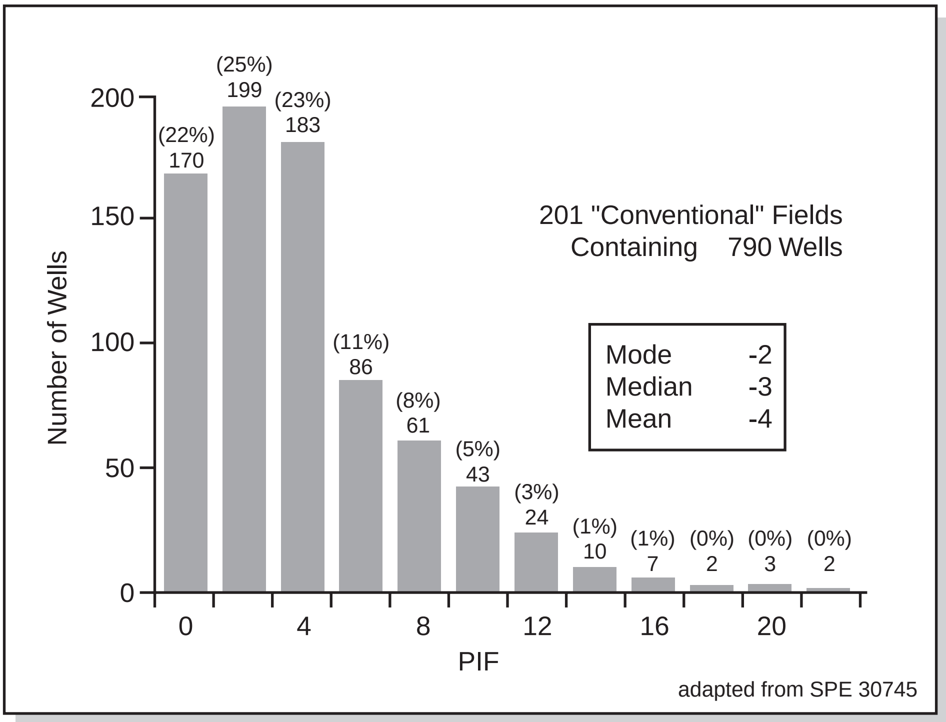


Figure 14
PIF Distribution for horizontal wells

More important is the cumulative recovery or reserves per well. Not very many horizontal wells have been abandoned so it is too soon to come to conclusions based on experience. A number of estimates have been made which fall in the range 2-4 times the reserves of a vertical well. To achieve the same reserves will require 25% to 50% of the number of wells required in a conventional field development.

2.8.2 Connection of Laterally Discontinuous Features

Naturally fractured reservoirs are an important source of reserves especially in basins with extensive carbonate deposits. Frequently in carbonates the matrix porosity and permeability are too low for commercial production rates but wells intersecting the fractures can produce at high rates. The fractures are close to vertical in deeper reservoirs and a vertical well may or may not intersect fractures, depending on their fracture density. A horizontal well has a better chance of connecting many fractures. It must be aligned to intersect the fractures normally, which means that the stress direction at the time of fracture creation must be known.

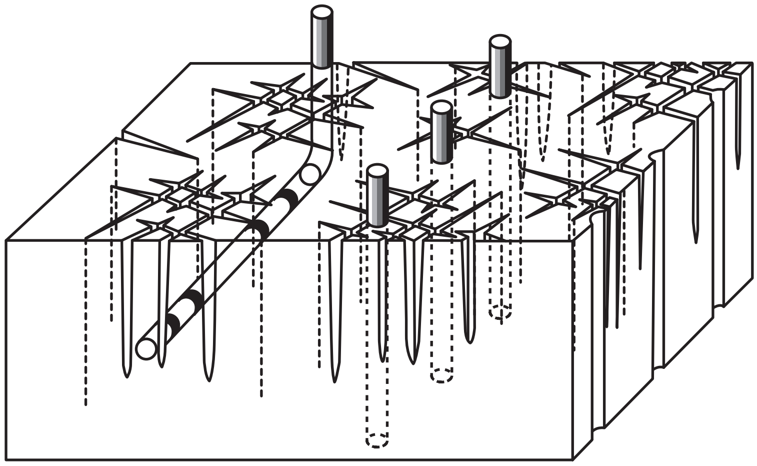


Figure 15
Vertical and horizontal wells connecting to a fracture network

Faulting is another type of reservoir heterogeneity that horizontal wells can exploit. While drilling the horizontal section the LWD (Logging While Drilling) response may suddenly go from reservoir to non-reservoir (Figure 16). If it is thought that this is due to traversing a fault then the well can be directed upwards or downwards in a search for the reservoir. It helps if there is good quality seismic available and the local faulting style is well understood.

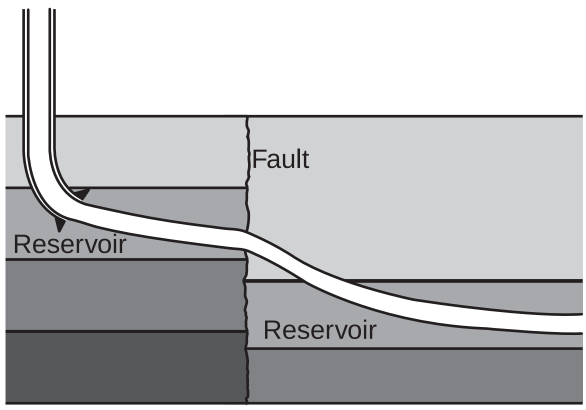


Figure 16
Fault block drilling

2.8.3. Changing the Drainage Geometry

Horizontal wells usually have greater PI's than vertical wells and, for a given productions rate, their drawdown will be lower. This lower drawdown helps delay the encroachment of unwanted fluids such as water or gas. For vertical wells this phenomenon is referred to as coning or cusping reflecting the shape of the disturbance to the previously level contact. With a horizontal well the shape becomes a crest. Figure 17 shows for a water-oil interface that the drawdown must overcome the buoyancy force for the distorted water-oil contact to reach the well. Clearly, the greater the distance of the horizontal well above the Water-Oil-Contact the greater the drawdown can be without water production. The engineer's job is to decide what this distance should be. This decision can be critical in an oil-rim reservoir or in the case of an unfavourable mobility ratio, such as often exists in heavy oil reservoirs. For an oil rim underlain by water the horizontal well must be placed parallel to the fluid contacts at a position which has been determined to be optimum with respect to the dominant reservoir drive mechanism (that is, gas cap expansion or aquifer influx).

This results in improved well recoveries. This decision will also be dependent on the position of inter-reservoir shale barriers.

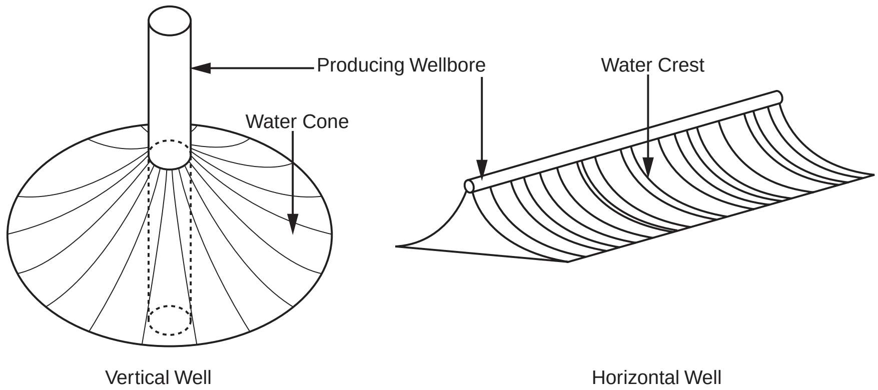


Figure 17
Coning (vertical wells) and cresting (horizontal wells) during production

2.8.4 Extending Field Appraisal Laterally

The most common method of field appraisal has been to drill (many) vertical wells and, by logging and testing them, to build up a geological and reservoir model to use in development planning. This process can be extended laterally using horizontal wells. It can be especially powerful in delineating stratigraphic traps where reservoir quality may degrade over a few kilometres. Examples of where appraisal by horizontal wells brings advantages are:

- Identification of complicated fracture networks
- Combination of appraisal and development objectives
- Appraisal of many fault blocks with one well
- Ability to penetrate top reservoir from below, useful when top reservoir is difficult to map

2.9 Disadvantages of Horizontal Wells

So far the emphasis has been on the positive aspects of horizontal wells. As expected, there are also disadvantages.

- The technology is more demanding of drilling and completion technology
- Use of substandard rigs or drilling assemblies will result in a substandard end product (the horizontal well)
- The personnel employed should also be highly trained and used to working in an innovative manner. This applies especially to the directional drilling specialist who is responsible for implementing geosteering proposals
- Horizontal wells usually have lower drawdown than vertical wells and may be more difficult to clean up
- The options for monitoring, control and intervention are often limited
- The cost of horizontal wells is higher, usually at least 20% higher

These disadvantages can all be conquered given sufficient determination and good planning. Probably the most important consideration is that there should be powerful management commitment, prepared to accept some disappointing initial results as the learning curve is climbed.

2.10 The Economics of Horizontal Wells

2.10.1 Costs

Horizontal wells normally take longer to drill than vertical wells in the same reservoir and, as noted above, require high specification equipment and specialist personnel. Experience to date shows that the first few wells in a horizontal drilling campaign may cost around twice that of a vertical well and later the ratio drops into the range 1.2-1.5 as more wells are drilled.

The operating cost of horizontal wells has not been widely reported to date. The top-hole section should have operating costs similar to a vertical well but the horizontal section may have additional costs if intervention is required for production logging, stimulation or isolation using coiled tubing.

2.10.2 Profitability Indicators

The standard oil field profitability indictors are used for well economics drawing from those widely used in petroleum economic. These are Net Present Value (NPV), Profit-to-Investment ratio (PIR), Payback Time and Cost-per-Barrel. They are cash flow based and defined as follows (using pre-tax calculations for simplicity):

(a) Net Present Value

The time period is divided into appropriate periods and the new cash flow determined for each period “i”. Net Cash Flow for period “i” is defined as Revenue – Cost, or

NCF_i = Hydrocarbon Quantity*Price – Capital Cost – Operating Cost

The sum of the NCF for the period of the project is commonly referred to as **Cumulative Cash Surplus or Ultimate Cash Surplus**. The **discount factor** for each period (using mid-year discounting at a discount rate d% per annum) is defined as:

$$df_i = \frac{1}{(1 + d/100)^{i-1/2}}$$

Discounted NPV(d) is then defined as:

$$\begin{aligned} NPV(d) &= \frac{NCF_1}{df_1} + \frac{NCF_2}{df_2} + \frac{NCF_3}{df_3} + \\ &= \Sigma_1^N \frac{NCF_i}{df_i} \end{aligned}$$

When using NPV it is important to quote both the discount rate and the reference date (the beginning of year 1 in the above example). NPV is the most direct and robust measure of value.

(b) Profit-to-Investment ratio

The PIR is defined as: $\dfrac{\text{Ultimate Cash Surplus}}{\text{Total Capital Expenditure}}$

It is generally more meaningful to use discounted quantities and to define

$$PIR(d) = \frac{NPV(d)}{Capex(d)}$$

Where Capex(d) is the total Capital Expenditure discounted at d% per annum in the same manner as the NPV above. PIR is a useful measure of the efficiency with which Capex is being deployed.

(c) Payback Time

This is the time at which the cumulative NCF (undiscounted) goes from being negative to being positive. Unfortunately there are projects for which this never happens and for which Payback Time therefore has no meaning. Payback Time tells managers how long the capital is at risk before being recovered.

(d) Cost-per-Barrel

For well projects the Operating Expenditure is usually ignored so Cost-per-Barrel is simply defined as:

$$PIR(d) = \frac{Capex(d)}{Pr oduction(d)}$$

This indicator is useful for comparing advanced well projects with conventional well projects. If the advanced well proposal has a higher cost-per-barrel then other reasons will have to be sought to justify it.

3. MULTI-LATERAL WELLS – AN INTRODUCTION

3.1 Introduction & Definitions

A multi-lateral well is defined as "a well which has more than one vertical, inclined or horizontal hole drilled from a single site and connected back to a single or 'mother' well bore". This section focuses on multi-laterals for which the branches are horizontal or close to horizontal in the reservoir.

The main reason for drilling a multi-lateral well is to increase the return on investment through improved reservoir drainage even though the initial well cost is higher. For example reported that the reserves per multi-lateral in the Austin Chalk (Texas, USA) have been reported to be 1.8 times the reserves per single lateral while the cost was 1.4 times that of a single lateral.

Since the late 1980's there has been a rapid increase in the use of multi-laterals, similar to that experienced with horizontal wells about ten years earlier. This increase has been driven by a significant number of applications and the wells have had various levels of sophistication in their design, from simple open hole sidetracks to wells where the branches could be re-entered or isolated selectively. These requirements have encouraged the service companies to invest in new methods of drilling and completing multi-laterals.

The first multi-laterals were drilled in Russia in the 1950's and 1960's, an example is shown in Figure 18. The technology was adopted and refined and the current examples are in the USA, Canada, Middle East and North Sea. A survey done recently of USA multi-laterals indicated typically two or three laterals per well and that 97% of applications were in reservoirs for which primary recovery was the dominant production mechanism. The application was usually in the case where horizontal wells were successful and further cost savings could be made by having fewer wellbores to surface. Combining a number of laterals into one multi-lateral thus made sense.

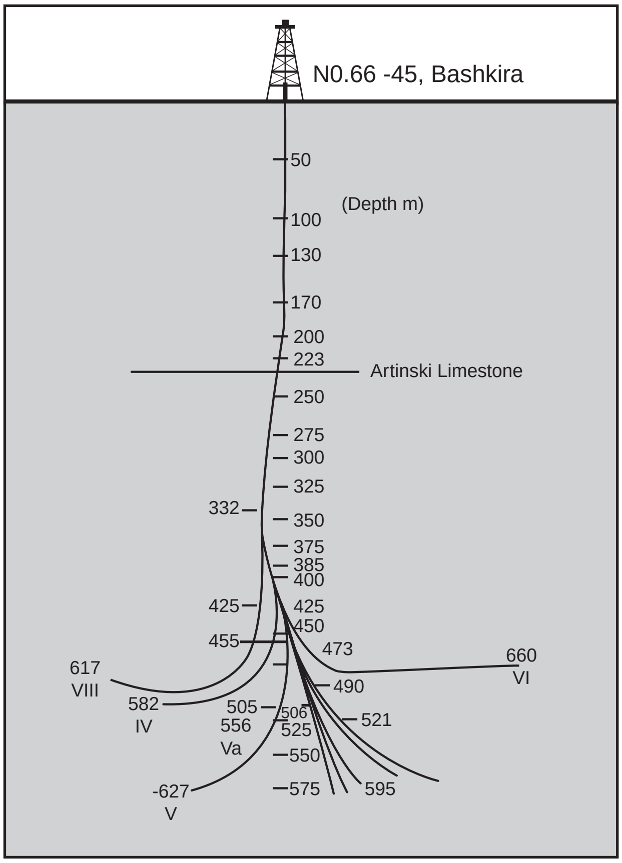


Figure 18
Bashkiria multilateral well

3.2 Factors Influencing the Potential Application of Multilaterals

There are many constraints in multi-lateral well design related to the operation of sidetracking out of the primary wellbore and the shape of the reservoir(s) targeted by the laterals. For example the primary wellbore may be 8 1/2 " hole with a gentle build angle while the sidetrack may be 6" hole with quite a severe build angle due to the small vertical distance between the junction and the reservoir. The laterals may have different lengths and different completions as a result of such geometric constraints. If the primary wellbore is highly deviated then the azimuthal separation between the laterals will be restricted. The process of multi-lateral well design often involves a few iterations between directional drillers, geologists and reservoir engineers before a satisfactory solution is found.

Many factors influence the decision of whether to deploy a multi-lateral. They can be used in new or existing fields; but it is helpful to already have some experience of horizontal wells in the area. In some cases, a lateral can be drilled in a new direction to acquire exploration/appraisal data and depending on its success, either be retained for production/injection or abandoned. Interference may take place between laterals either in the reservoir or in the wellbore.

If the laterals are being drilled in the same reservoir or in communicating reservoirs, the drainage areas will eventually overlap at later time. If this is so, then the resulting drainage area will be less than would be the sum of the drainage areas for the laterals individually, as indicated in Figure 19. However, for low permeability reservoirs the transient period may last for a long time and significant acceleration of production will be achieved before interference effects reduce production.

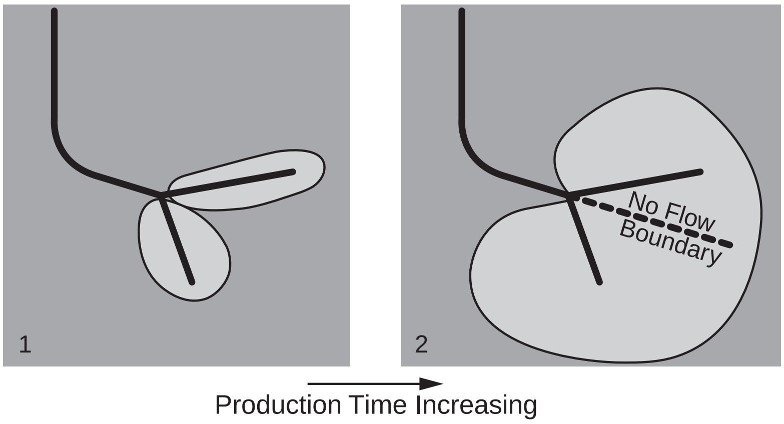


Figure 19
Multi lateral nterference

In non-communicating reservoirs, for example, in a sequence of stacked reservoirs, the same issues arise in a vertical well when deciding whether to perforate two independent flow units. Interference will take place in the wellbore unless a completely independent dual completion has been used (Figure 20). Generally it would be unwise to use a commingled completion if the reservoirs are in different pressure regimes because of the negative impact of cross flow. For reservoirs at the same pressure regime commingled production when producing dry oil causes no problem unless severe differential depletion takes place (Figure 21). With the advent of water cut in layer 1 a back pressure will be experienced due to the higher density of the fluid in layer 1 causing undesirable cross flow into layer 2.

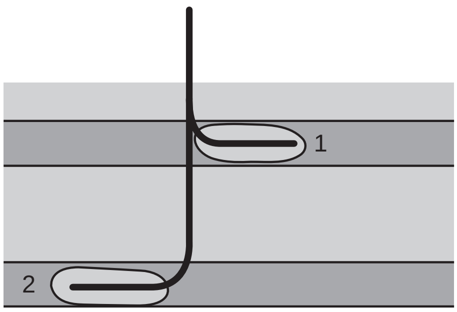


Figure 20
Multi lateral interference effects in the wellbore

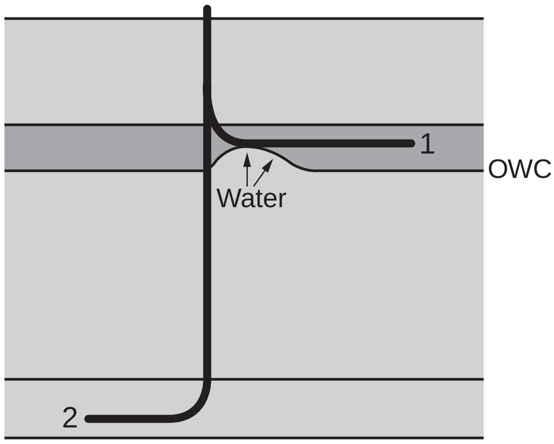


Figure 21
Water breakthrough affects the performance of both zones in a multi lateral well

3.3 Impact on Recovery and Rate

In many cases multi-laterals do not increase ultimate recovery but simply accelerate production. This in itself can be beneficial in areas where costs and risks are high. To achieve both acceleration and improved recovery as shown in the sketch it is necessary to exploit the geology to the fullest, understanding the barriers to both lateral and vertical flow. The positioning of the laterals in the reservoir will be critical and it may be necessary to provide intervention possibilities to facilitate reservoir management.

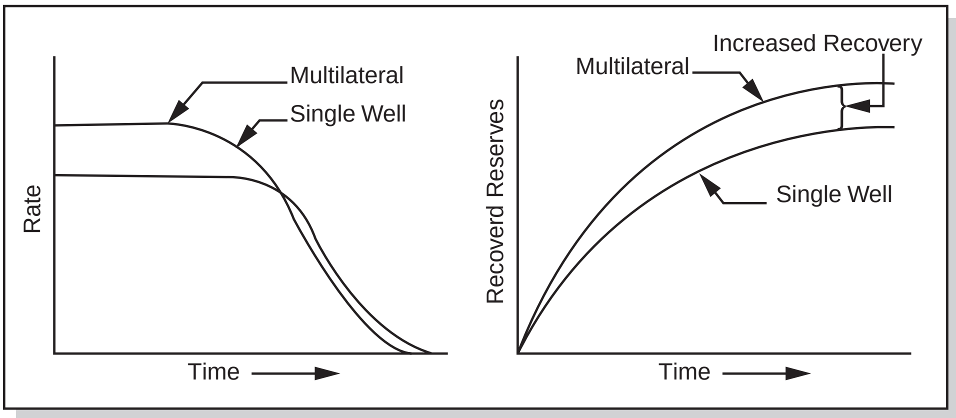


Figure 22
Economic benefits of Multilaterals

3.4 Initiation Methods for Laterals

Laterals can be initiated by a number of different methods:

- Openhole sidetracks drilled with or without whipstock
- Milling sidetracks from existing cased wellbores with full bore whipstock
- Miling sidetracks with small diameter whipstock passed through tubing

The first method is usual for carbonate reservoirs, particularly onshore where openhole completions are acceptable for horizontal wells. The second method is the method of choice for high rate wells where a large diameter lateral of significant length is required. Method three is good for coiled tubing drilled sidetracks.

3.5 Principal Multilateral Geometries

The three basic geometrical configurations are planar, stacked and opposing.

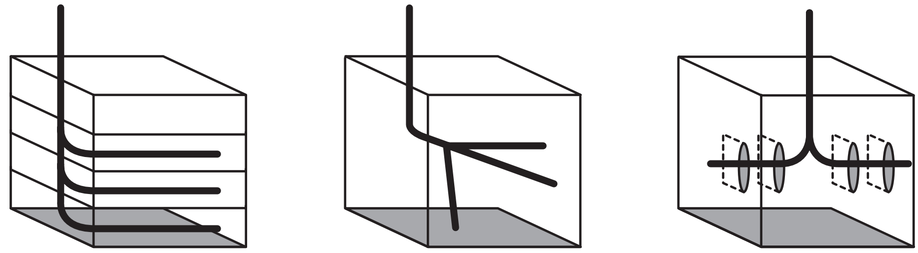


Figure 23
Multilateral options employed in the field

The *planar* configuration is useful in naturally fractured reservoirs where there is some uncertainty about fracture orientation. Having three laterals with 45º angles between them is almost certain to intersect fractures at a reasonable angle to the original well, unless the spatial distribution of fractures is very clustered. The Dan field in the Danish sector of the North Sea is a good example of this type of well.

The *stacked* configuration is designed for non-communicating layers and has been applied successfully in Dos Cuadros field offshore California by Unocal. The stacked configuration may be also useful in low permeability reservoirs where there is a long period of transient production and flow interference does not become significant for some time.

The *dual-opposed* configuration has the advantage of giving the largest drainage area for a given length of wellbore – it minimises interference at the heel of the well. This configuration has been applied successfully in numerous wells in the Austin Chalk, Texas by URPC.

3.6 Applications of Multi-Lateral Wells

In this section the benefits and constraints of multi-lateral wells are discussed and then illustrated. The benefits are both economic and technical and are balanced by costs that are discussed towards the end of the section.

3.6.1 Benefits of Multilateral Wells – Economic & Technical

The economic benefits of multi-lateral wells arise from the fact that the conduit from surface to the reservoir only has to be drilled and completed once. Conventional wells require that each traversal of the reservoir required its own conduit to surface. Multi-laterals can have a major impact offshore by increasing the production and pay section exposure for each slot available from a fixed platform or subsea template. Since the cost of platforms and templates is related to the number of slots, multilaterals can have a beneficial effect of reducing capital costs. This is especially true in new field developments where, in some cases, marginal fields can be transformed into economically viable developments.

The same effect can benefit onshore development by reducing the pad size of the drilling location due to having fewer wells per pad. Onshore permit and planning costs can be reduced simply through having a smaller “footprint” on surface. There may also be benefits in terms of reduced flowline and pipeline length. The environment can also benefit due to lower impact of a smaller surface presence.

There may be some economic disadvantages that need to be recognised and managed at an early stage. The risk is now being concentrated into a smaller number of wells that may be dependent on new, untried technology. In the longer term there may be some additional operating costs due to uncertainties in reservoir and mechanical performance. One of the branches may experience premature water breakthrough and require installation of a scab liner or a plug. There may be an unexpected mechanical problem at a junction causing an undesirable leak of gas requiring intervention. These disadvantages are difficult to quantify but need to be addressed.

Technical advantages of multi-laterals centre on greater reservoir exposure at lower cost. All the advantages of horizontal wells can be captured at lower cost per reservoir foot. To reiterate:

- Increased exposure to the reservoir
- Connection of laterally discontinuous feature
- Changing the geometry of drainage
- Extending field appraisal laterally
- Reduction in drilling costs and risk

It must be recognised that there are also technical disadvantages. Multi-laterals generally entail greater risk. Well intervention will be more difficult and reservoir monitoring and management that requires such intervention is currently limited in scope. Drilling and completion of multi-laterals introduces new difficulties in well control and also in impairment and cleanup of individual branches.

3.6.2 Application of Multilateral Wells

The applications of multi-lateral wells to oil and gas fall under two broad headings:

- improved commerciality of reserves
- data acquisition/delineation/risk reduction

Improved commerciality of reserves is achieved either through:

- enhanced physical access
- reduced investment costs
- extended longevity of wells

Enhanced physical access can be achieved through greater vertical access, improved areal drainage or higher production rate that gives acceleration of recovery.

Reduced investment costs arise due to increased reservoir footage exposed per mother wellbore.

Extended longevity of wells comes about through extended production life before well reaches economic limit, improved reliability and the ability to defer production of unwanted substances such as sand, water or gas.

Data acquisition/delineation/risk reduction comes about due to:

- well data
- reduced inter lateral spacing
- more data per well

Well data may provide increased geological and lateral stepout data, especially through infill data. The speed of acquisition may be quicker leading to faster development.

There are numerous applications of multi-lateral wells; the main reservoir applications will be the focus here:

- viscous oil
- layered reservoir
- faulted/compartmentalised reservoirs
- depleted and mature field development
- tight and naturally fractured reservoirs

Viscous oil reservoirs have a productivity that is, in general, constrained by a poor mobility ratio, i.e. (Permeability/Viscosity or k/μ) is low. To combat this and the associated high drawdowns, maximum formation exposure can be critical to achieving economic flowrates. In such cases, borehole area exposure can be more important than borehole diameter. The use of ultra short radius wells of limited lateral length can be adopted to target such reservoirs which show a reduced formation thickness and low reservoir pressure.

Layered reservoirs can be efficiently exploited using the stacked multi-lateral configuration (Figure 24). Care must be taken to plan carefully the degree of interaction of the laterals in the completion. If the pressure regimes are significantly different then it may be necessary to install separate tubings. These are strings isolated all the way to surface. The economics will be better if it is possible to commingle flow at the reservoir level.

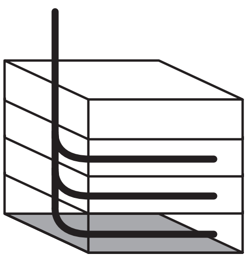


Figure 24
Three layer stacked multilateral

A reservoir in which the reserves are divided among many compartments is a good candidate for multi-lateral application especially if some of the compartments have reserves below the level at which an individual well could be justified. In drilling such wells, knowledge of the fault locations and experience of drilling in the fault zone will be important (Figure 25). Placing of the junction relative to the faults will also be important. A high-resolution 3D seismic survey with good well control will make drilling such wells easier.

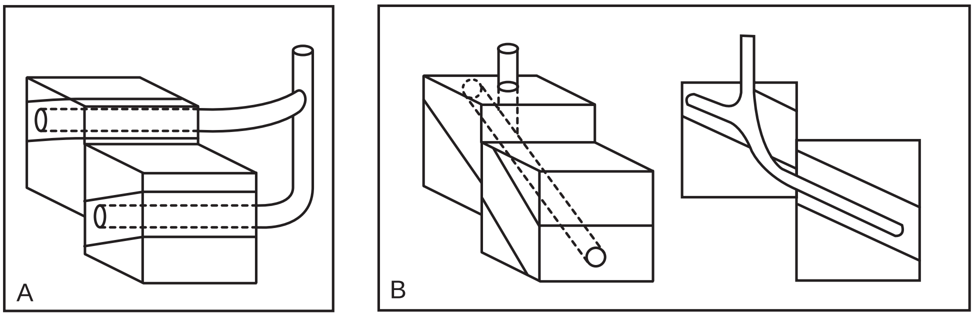


Figure 25
Multilateral configurations to access reserves across a fault block

Fields with many years of production history can lend themselves to multi-lateral application especially when the pace of development in various zones is different. Figure 26 shows two zones, one with good permeability, already quite well flooded, the other with lower permeability and still only partially flooded. The high permeability layer can produce quite well through a vertical wellbore but the low permeability is better suited to a horizontal wellbore so there is now a better chance of comparable oil rates in the two laterals.

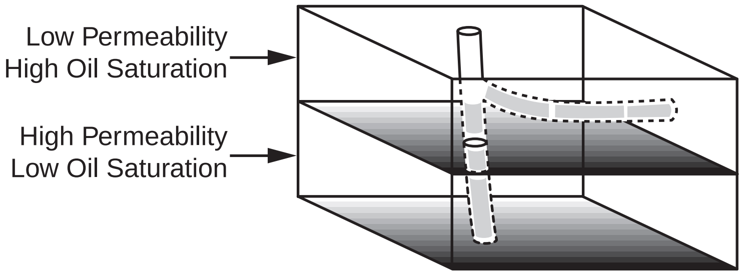


Figure 26
Mature field redevelopment of layered reservoirs

Tight (low permeability) and naturally fractured reservoirs can be exploited using planar configurations with two or more laterals being used. For tight, unfractured reservoirs a number of branches at various angles will be appropriate, increasing the reservoir exposure cost effectively. For the naturally fractured case it depends on how well the fracture orientation is known. If this orientation were relatively poorly known then it would make sense to try a few different angles, testing the production rate in each lateral to determine which is the most favourable orientation.

Besides these mainstream applications a number of more unusual applications of multi-laterals have been made:

- Multi-laterals to appraise reservoir connectivity
- Secondary and enhanced recovery applications
- Special applications for marginal fields
- Improving commerciality of tight gas fields
- Multi-laterals for HP/HT development
- Multi-lateral wells for fluid disposal
- Multi-lateral to reinject produced water

An interesting example of a multi-lateral application has been provided by Mobil North Sea Limited from their Galahad gas field in the UKCS sector of the southern North Sea (Figures 26 and 27). This low permeability gas field produces dry gas from the Rotilegendes sandstone. Previous wells have been either hydraulically fractured or drilled horizontally. The well objective for Galahad well 48/12a-7Z/7Y was to connect and appraise upper zones D, E and F. It was constrained to be a multi-lateral from an existing well in order to maintain production from the original wellbore. The operator wished to use adaptive technology in a simple fashion. The well completion used is shown in the adjacent sketch.

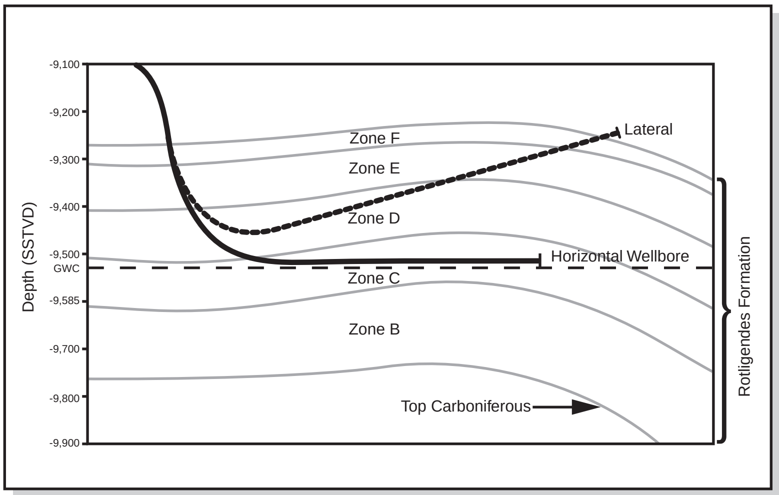


Figure 27
Galahad field – Multilateral placement

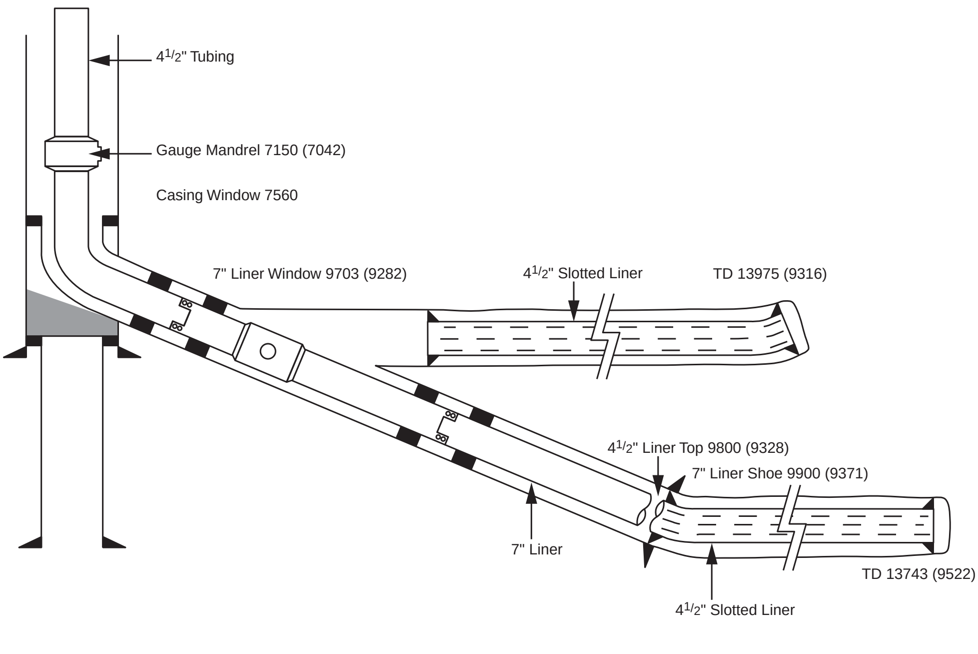


Figure 28
Galahad Multilateral – completion

Characteristics of multi-lateral well costs can be summarised as follows:

- Capital cost per well is higher
- However, total field development cost will be lower due to the reduced well count
- Operating cost – aim is to reduce operating cost
- Well cost is very dependent on well complexity and completion system used

4. EXTENDED REACH WELLS

The main characteristic of extended reach wells is a substantial horizontal displacement (HD) to (True) Vertical depth (TVD). A ratio of 2:1 is quite common. More recently BP has achieved a ratio of 10:1 at Wytch Farm. The size of the ratio depends on three factors:

- TVD
- Drilling conditions/lithology
- Equipment/technology capabilities and limitations

If the reservoir is very deep then the total length of the well restricts the size of the ratio. If drilling conditions are arduous leading to high torque or low rate of penetration then a high ratio will be difficult to achieve. Finally, the rig must be of a high standard with an adequate top drive and draw-works to handle the string weight and torque likely to be experienced.

The unique advantage of extended reach wells is greater reach so that more area of reservoir can be accessed from one drilling centre. A number of other advantages overlap with the advantages of either horizontal or multilateral wells:

- Reduced number of wells
- Greater wellbore contact area leading to lower drawdown
- Improved connectivity of compartments and layers

There are a number of constraints associated with extended reach wells:

- Concentrated risk due to the length and difficulty of the well
- Higher unit well costs
- Drilling limitations both in the topsides equipment and downhole due to high torque and drag
- Completion limitations caused by the distance to the reservoir and the length in the reservoir
- Flow monitoring and intervention are restricted by the well geometry

A summary of extended reach wells from around the world is shown in Figure 29 below. Wytch Farm well M11Y has the greatest HD:TVD ratio shown, later wells achieved horizontal departures greater than 10.5km.

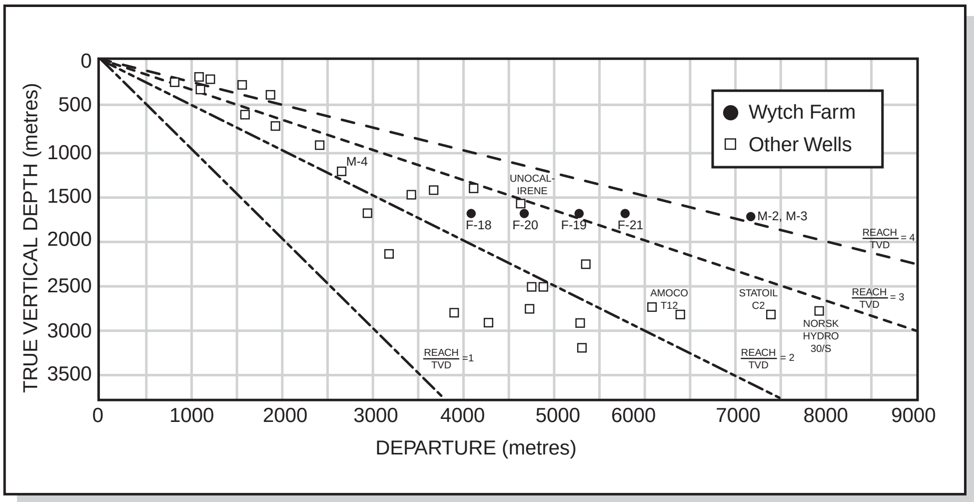


Figure 29
Examples of Extended Reach Drilling

Extended Reach Drilling applications are most suitable for:

- Thicker reservoirs. The wellbore will penetrate a larger borehole length from top to bottom of the reservoir if the angle is high
- Multiple layers they will also be fully penetrated from top to bottom
- Shallower formations. Depths less than 3000m TVD are favoured by the current technology
- Drilling from a central location

Well known examples of ERD application are at Wytch Farm field, onshore UK by BP and in the Norwegian sector of the North Sea by Norsk Hydro and Statoil. In retrospect it would now be been possible to develop some of the North Sea giant fields using fewer platforms with ERD to provide greater drainage area per platform i.e. The Brent Field with one rather than the four platforms installed in the 1970's. ERD technology could also have been used at THUMS, Long Beach, California where artificial islands were created offshore to serve as drilling centres.

5. MULTIPLE FRACTURED HORIZONTAL WELLS

In some circumstances it is beneficial to fracture horizontal wells, especially in fields where most vertical wells are fractured to achieve commercial rates. For reservoirs deeper than 500' (150m) the hydraulic fracture plane will be close to vertical and parallel to the direction of maximum stress. A vertical well will be suitably oriented to accept the flow of fluid from such a fracture. The orientation of the horizontal well will effect the connection with the fracture oriented to accept horizontal well may intersect such vertical fractures at angles from 0˚ (“Longitudinal”) to 90˚ (“Transverse”) in Figure 30.

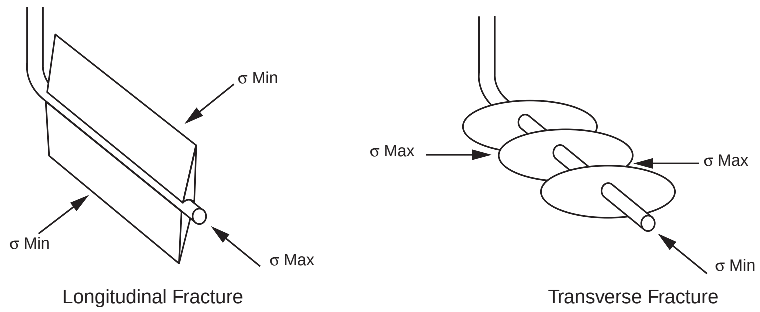


Figure 30
Longitudinal or transverse fractures intersecting a horizontal well

This angle depends on the horizontal well orientation relative to the principal stress direction. The connection from reservoir to well via the fracture is influenced by this angle. For values close to 90˚ more than one fracture will be required (Figure 31). In this example production increases for up to four fractures are required and diminishing returns are reached for further fractures. In a closed box-like reservoir (Figure 32) the PI ratio depends on the dimensionless fracture length $2x_f/L$, increasing more with $2x_f/L$ as the number of fractures (n) increases.

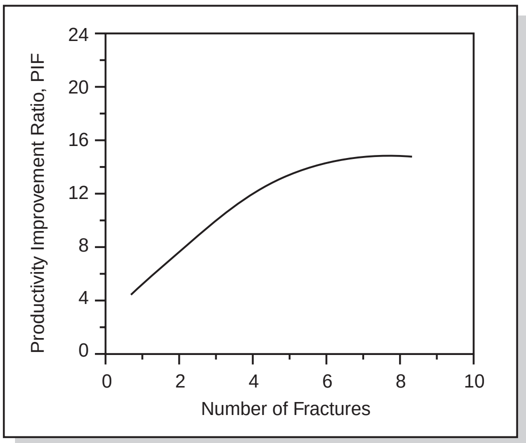


Figure 31
Effect of number of fractures on Productivity Improvement Factor

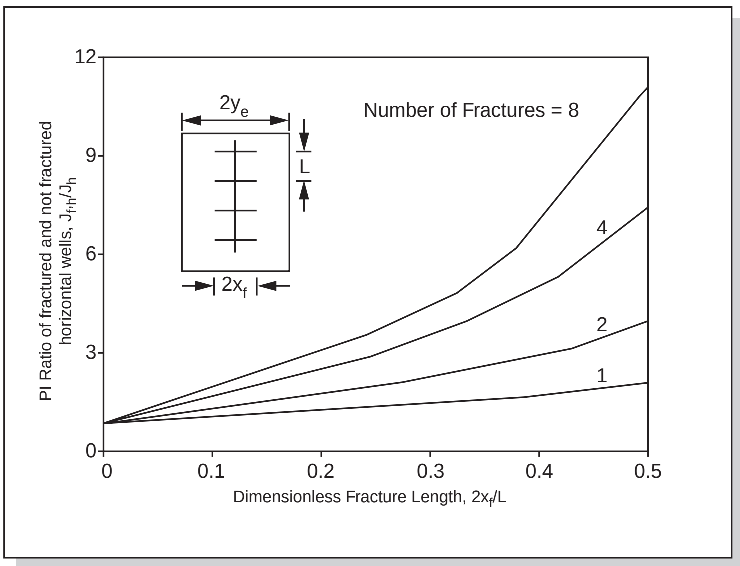


Figure 32
Effect of fracture opening on well productivity for a horizontal well in a box-like reservoir

An interesting comparison of a fractured and an unfractured horizontal gas well is shown in the Figure 33 which shows the rate vs. time for different well configurations. An open hole horizontal well is compared with the cases of 1, 2, 3 & 5 fractures. The open hole horizontal well can produce more than the cases of 1 and 2 fractures and it is only when 3 or more fractures are created that the fractured well is superior. This effect is due to flow convergence with a small number of fractures.

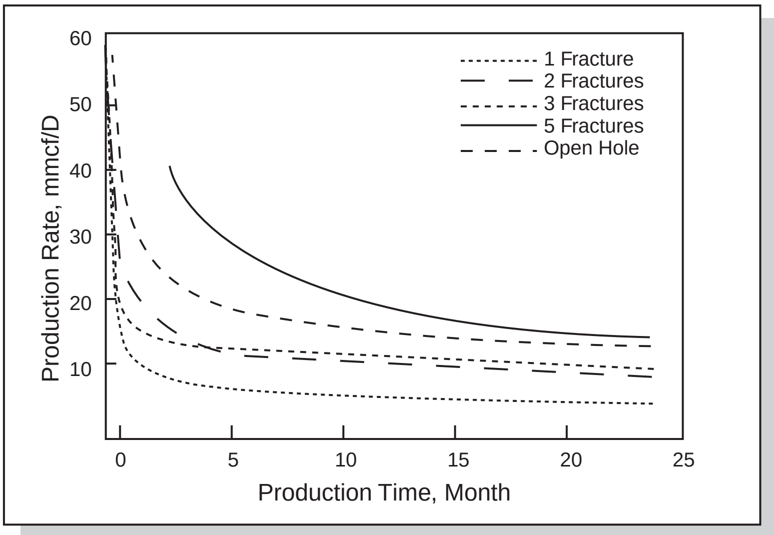


Figure 33
Production decline

6. UNDERBALANCED OPERATIONS

The main benefit of underbalanced operations to minimise impairment giving an improved well PI. There may also be a secondary benefit of improved drilling penetration rate. The benefits are difficult to quantify and to implement underbalanced operations safely and efficiently, requires special equipment and increased costs.

Reservoirs for which underbalanced drilling (UBD) is likely to be successful include:

- Highly permeable consolidated intercrystalline sands and carbonates
- Highly permeable/poorly consolidated sands
- Macro-fractured formations
- Underpressured/depleted formations where conventional drilling would exert more than 1,000 psi hydrostatic overbalanced pressures

There are also some reservoirs where underbalanced drilling might be successful:

- Formations containing significant concentrations of water-based mud filtrate sensitive materials
- Formations exhibiting severe potential incompatibility issues with water based mud filtrates
- Dehydrated formations exhibiting sub-irreducible water saturation or hydrocarbon saturation

Underbalance techniques are difficult to maintain with conventional rotary drilling, but **Coiled Tubing Drilling** offers the capability to drill and complete in a continuous underbalanced operation. Some advantages of Underbalanced Coiled Tubing Drilling are:

- Reduction of wellbore impairment
- Theoretical elimination of mud losses
- Improved rate of penetration due to reversed chip hold down effect
- Improved hole cleaning
- Extended bit life
- Well immediately ready for production/accelerated production + minimal exposure time
- Decrease in differential sticking and key seating
- Ability to test well while drilling

The use of UBD has two beneficial effects on production. The resulting higher PI will give a higher production rate and the reduced drilling time will mean that the well may be brought into production earlier.

Use of UBD will give maximum benefit if the completion is also underbalanced so that the well is never killed before being brought on to continuous oil production. Coiled or reeled tubing completions provide this possibility. There are some impairment mechanisms that need to be taken into account; such as glazing due to excessive temperatures at the bit and imbibition of fluid into the formation in spite of the underbalanced condition.

As well as the above impairment mechanisms there are a number of potential disadvantages of UBD:

- Wellbore stability/near wellbore mechanical damage
- Failure to keep the underbalanced condition throughout the reservoir payzone
- Well control problems/control of production while drilling
- Reservoir cross flow
- Poor knowledge of original reservoir pressure
- Slug flow and liquid hold up in the vertical section of the wellbore
- Fallout of cuttings if circulation is stopped, leading to mechanical stuck pipe

7. SMART/INTELLIGENT WELLS

Smart wells are normally but not necessarily horizontal wells, equipped with downhole monitoring and control. To date, systems use surface readout so that data from downhole measurements of pressure, flow rate and flow stream composition are available at surface. These data can be processed and then used to adjust flow control devices commanded from surface. In principle the downhole information could be used directly for downhole control; but so far this step has not been taken.

The main driver leading to smart wells has been the problem of reservoir management in horizontal wells. Reservoir management has the objective of ensuring that the reserves of each flow unit are efficiently extracted with a minimum of unwanted fluids such as water. This requires the ability to close off perforated intervals and/or open new perforated intervals. The methods of perforating and of setting bridge plugs and scab liners in cemented casing used in conventional vertical wells are more difficult in horizontal wells. If the well were divided into a number of segments, each of which could be monitored and controlled separately, then more efficient reservoir management could be practiced. It could also reduce operating and processing costs as well as reducing workover frequency.

Conventional workover methods as describe above have a number of drawbacks:

Timing Availability of equipment, crews, rig of Diving Support Vessel

Cost A typical straddle isolation (zone change) can take up to 10 days, plus the deferred oil during the intervention. A subsea zonal isolation treatment can be ten times more expensive than a platform job. One operator has quoted a cost in the North Sea of greater than £2 million.

Risk Straddle isolations have an inherent risk due to mis-settings, elastomer swelling and failure to retrieve.

Constraints Limitations to further downward development without drilling out plugs

There are a number of cases which benefit from selective development and management:

- thin zones
- compartmentalised reservoirs
- vertically isolated sand units
- heterogeneous sand unit

7.1 Thin Zones

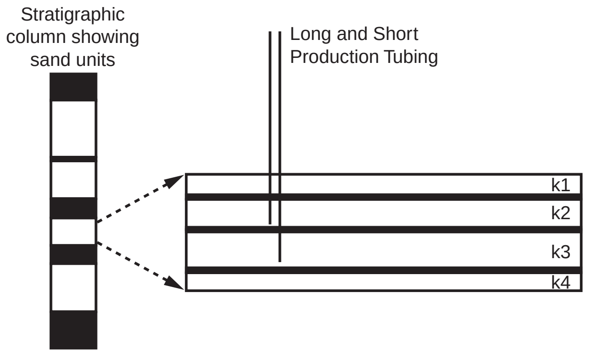
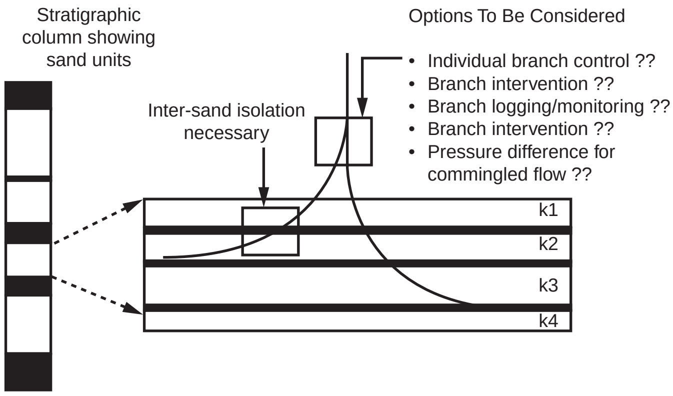


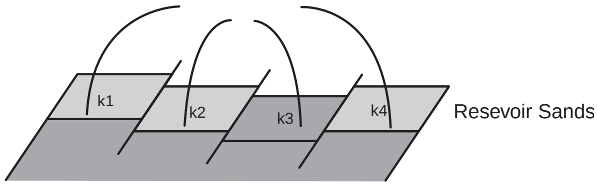
Figure 34
Dual completions are not really suited to thin zones

Figure 35
With monitoring and control devices shown the well can now be operated with either or both intervals flowing and the flow rate can be maximised.



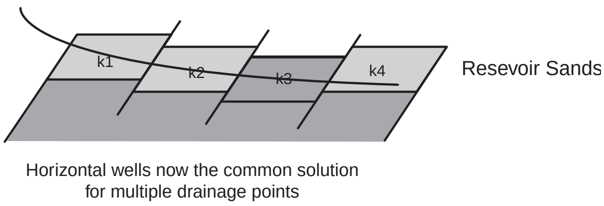
7.2 Compartmentalisation

Figure 36
Conventional approach to drain compartments too small to support single drainage points



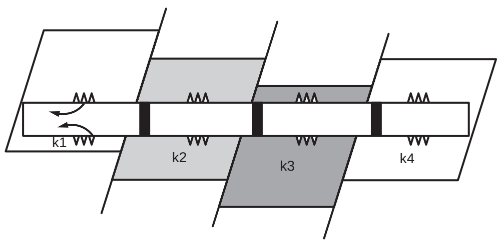
An individual well can be drilled to each compartment but the compartments may be too small to justify the cost of the four separate wells shown. (Figure 36)

Figure 37
Connecting multiple compartments with horizontal wells, but can the drainage be effectively managed?



On the other hand, a horizontal well could access all these compartments with just one wellbore (Figure 37); but there may be a requirement to manage the drainage.

Figure 38
Inclusion of flow control for each reservoir compartment



The compartments could be sequentially completed (Figure 38) but this may give an excessively low production rate and could also have high intervention costs each time an interval is to be changed.

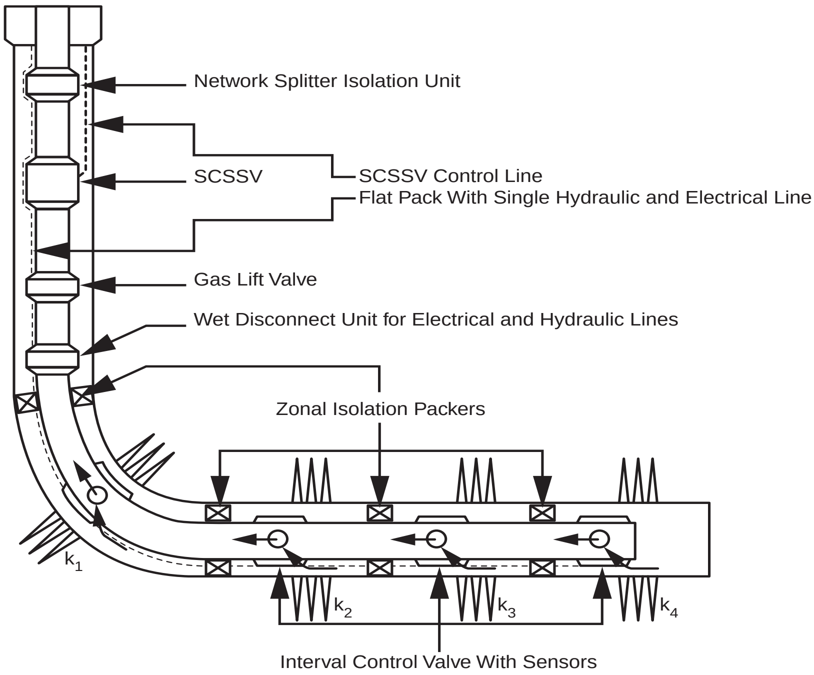


Figure 39
An "Intelligent Well" completion

The best solution may be to use an "intelligent" well completion with monitoring and depletion control of each of the four compartments independently (Figure 39).

8. COILED TUBING DRILLING

The two defining characteristics of coiled tubing drilling (CTD) are the use of continuous pipe spooled from a reel and the provision of drill-bit rotation by pumping drilling fluid through a mud motor located just behind the bit. A downhole thruster is also required to provide the necessary "weight on bit".

There are many arguments in favour of CTD some of which are:

- Drainage of remaining oil from smaller pockets
- Improved production using multilaterals
- CTD can be carried out through tubing
- CTD operations can be done underbalanced (UBD) resulting in less formation damage
- CTD can be deployed in situations where drilling facilities have been mothballed or previously removed
- CTD can be used simultaneously with conventional drilling units
- Additional production assessed through CTD can utilise "free" production plant capacity
- Replacement of jackups and other mobile rigs for wellhead platform drilling
- Small footprint
- Reduced mobilisation cost
- Ever increasing world-wide availability
- Shortage/high cost of alternative drilling facilities

- Less manning required
- Reduced cost because of more efficient operations
- Safer operations with fewer personnel exposed to drilling hazards
- More friendly to the environment

The basic elements (Figure 40) of a coiled tubing unit (CTU) are the **coiled tubing reel**, which stores the coiled tubing and from which it is reeled into the well, the **gooseneck** which acts as a guide, turning the coil through an angle of 120º before the **injector head** whose function is to push the CT into the well through the **stuffing box**, **BOPs**, and **lubricator** the latter being attached to the top of the **wellhead**, as for wireline operations. A power skid to power the reel and injector head is located close to the coiled tubing reel. A control skid from which the operations are controlled is set up with a good view of the reel and gooseneck.

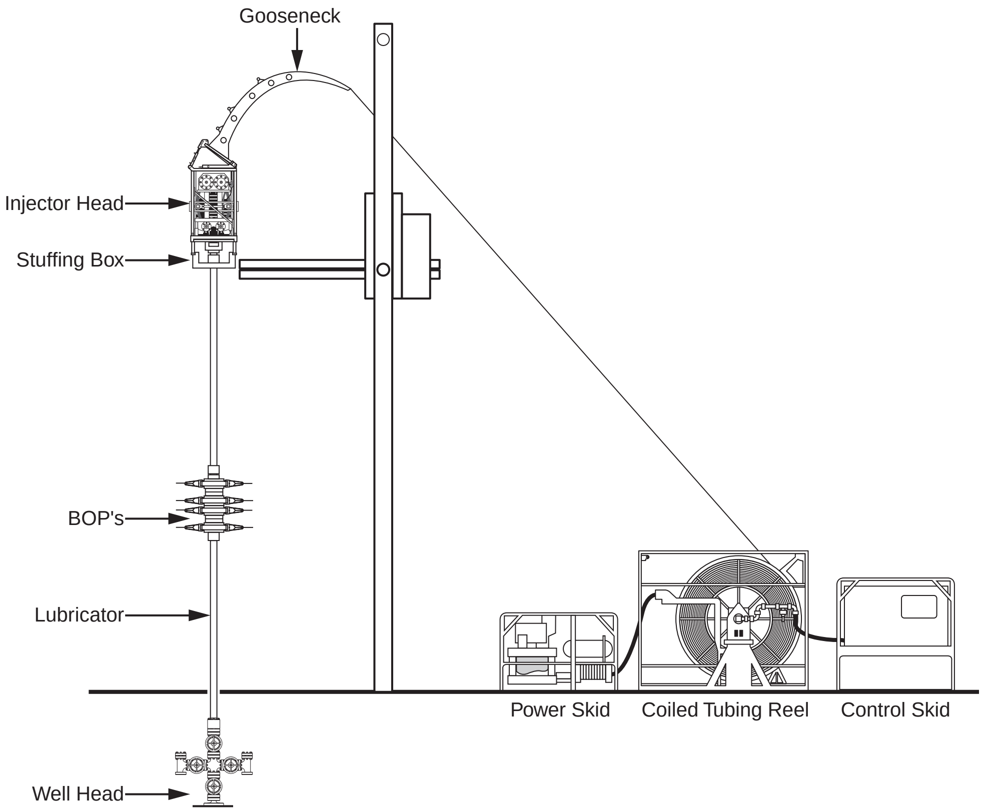


Figure 40
Coiled Tubing Unit rigged up on wellhead

Some of the technical advantages of CTD are:

- No pipe handling
- Continuous circulation
- Electrical wireline can be run inside the CT
- Underbalanced CTD is better than conventional UBD
- Can drill through existing completion
- Stand alone system
- Ease of mobilisation and small footprint

- Low noise level
- CTD is safer than conventional drilling
- Can be automated
- Can handle higher wellhead pressures and downhole temperatures

Some disadvantages of CTD are:

- Smaller hole sized available which will limit production rates
- Well length and weight on bit limitations
- No pipe rotation which can lead to stuck pipe
- Limit on length of horizontal section that can be drilled
- No jointed pipe handling provided on a simple CTU – may be required for running casing or making up a tubing string
- Buckling of CT may be a problem
- Strength and coil diameter limitations
- Life of string is limited by the number of trips into and out of the hole
- With larger sized of CT there may be limitations in the size of reel that can be transported by road
- Lifting capacity of offshore cranes may be a limitation
- Small internal diameter of CT may impose hydraulic limitations

While underbalanced CTD is an attractive option there are a number of disadvantages that need to be overcome:

- The snubbing force and stripper pressure required increases as the WHP increases
- Snubbing force increases with pipe size when WHP is held constant
- Chances of mechanical failure on coil above the stripper increases with snubbing force
- Increase in internal pressure in the coil reduces the cycle life
- Larger diameter coil has lower cycle life than small diameter pipe
- The low density drilling fluid used in UBD leads to less effective cooling/ cleaning of the bit

The evolution of CTD in the 1990's has seen a gradual increase in the number of new wells drilled using CTD. In 1990 twice as many CT wells were re-entries of old wells compared with the drilling of new wells. During the 1990's the number of new CT horizontals drilled annually increased by a factor of three; while CT re-entries only showed a modest increase.

The principal applications for CT re-entries are to extend the existing production interval or to reach new well targets. The completion diameter can be up to 41/2 in. outside diameter. Many of the re-entries can be through tubing. The newly drilled section may be a branch of a multilateral. BP in Alaska have perfomed over 40 such jobs have been done without pulling the existing completion. A thorough-tubing retrievable whipstock and window milling system has been used. The outturn cost was 50% less than the cost of a conventional workover.

A variation on CTD through tubing re-entries has been done on Lake Maracaibo, Venezuela using conventional rigs with slimhole drillpipe and downhole motor.

A Hybrid CTU is a unit equipped for pipe handling so that casing or tubing can be made up if required. Hybrid CTU is becoming widely applied in Alaska, but a number of offshore re-entries have been done using hybrid CTD in the North Sea. The latter have given underbalanced penetration of reservoirs with reduced mobilisation costs. While technically successful they have not so far been particularly economic.

Course:- G19PT
Class:- G137*
G137X

HERIOT-WATT UNIVERSITY
DEPARTMENT OF PETROLEUM ENGINEERING

Examination for the Degree of
MSc in Petroleum Engineering

Production Technology 1

Wednesday XX April 200X

09.00 – 12.00

NOTES FOR CANDIDATES

1. This is a Closed Book Examination.

2. Examination Papers will be marked anonymously. See separate instruction for completion of Script Book front covers and attachment of loose pages. Do not write your name on any loose pages which are submitted as part of your answer.

3. Question 1 is compulsory. Three questions are to be answered from questions 2-7. Answers should be written in separate answer books as follows:

Question 1	Blue
Question 2-7	Green

4. Where necessary please state any assumption that you made in answering the questions.

Question 1

1(a)
The flow characteristics of a hydrocarbon in a vertical tubing string vary as the position of the fluid in the tubing varies. Describe fully, the main flow regimes that would be encountered in a well producing fluid from a reservoir containing oil and dissolved gas. The flowing bottomhole pressure is above the bubble point pressure.

[20]

1(b)
A well and reservoir have the following completion and reservoir data. There is zero water cut.

depth of tubing	6000ft
average reservoir pressure, $\bar{P}_r$	2700psi g
PI (linear)	2.3b/d/psi
wellhead pressure, P_{wh}	160psi g
gas liquid ratio	400scf/b
tubing diameter	4in

Determine the bottomhole flowing pressure.

[20]

Figures 1 to 4 are the required Flowing Gradient Curves

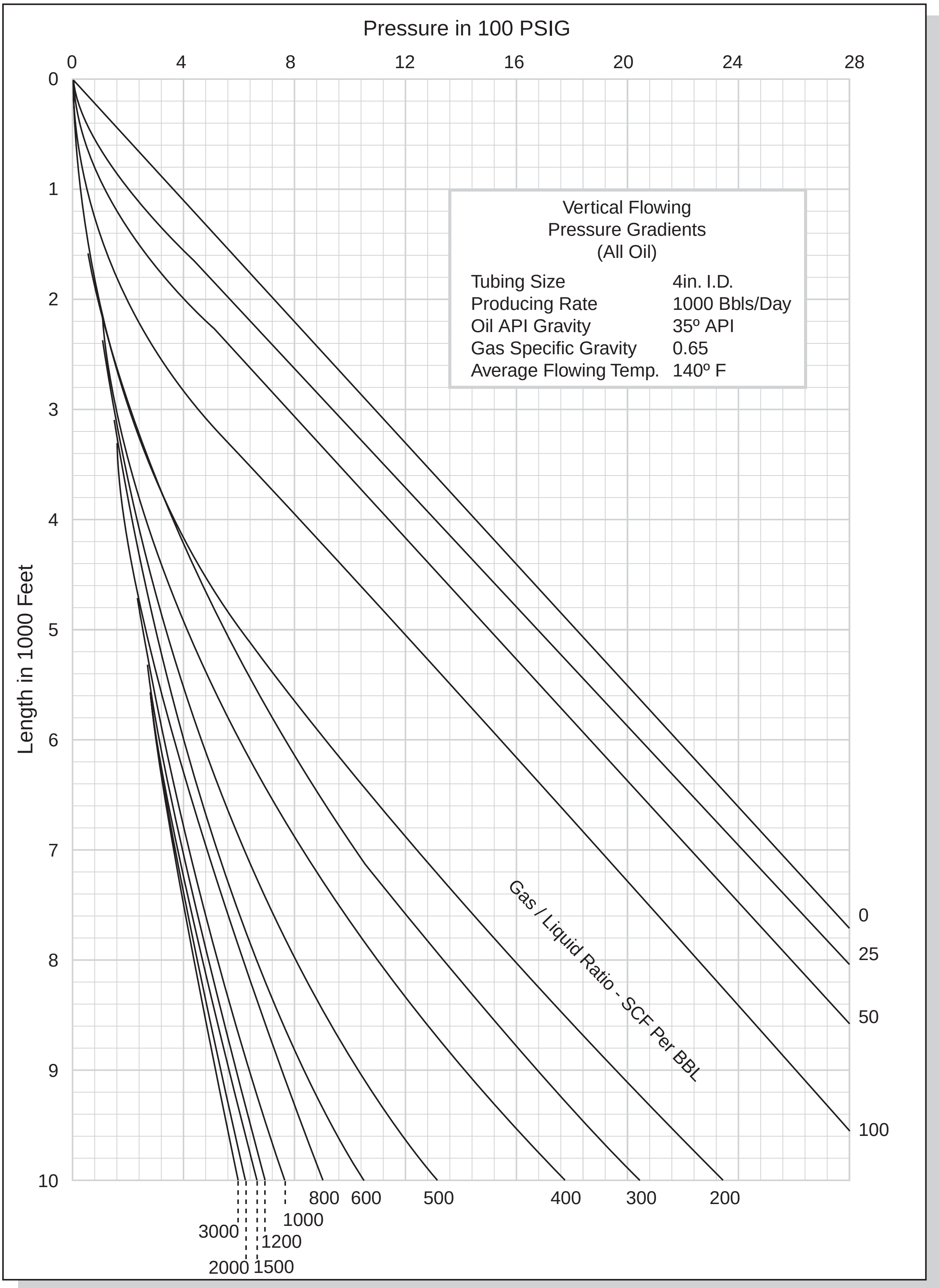
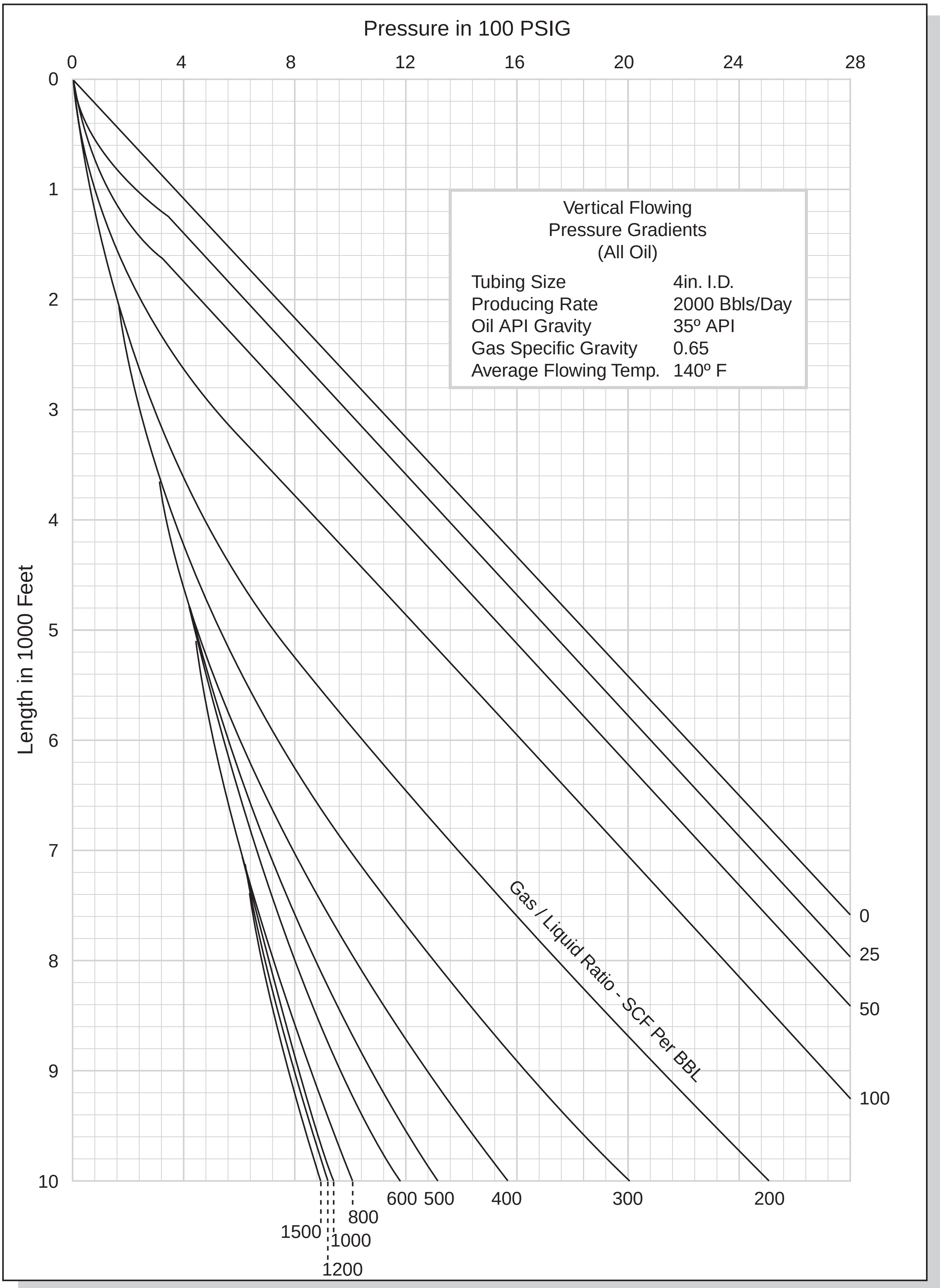

Pressure in 100 PSIG
0
4
8
12
16
20
24
28
Length in 1000 Feet
0
1
2
3
4
5
6
7
8
9
10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 1000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
200
300
400
500
600
800
1000
1200
1500
2000
3000

Figure 1


Pressure in 100 PSIG
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28
Length in 1000 Feet
0
1
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8
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10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 2000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
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200
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400
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600
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1000
1200
1500

Figure 2

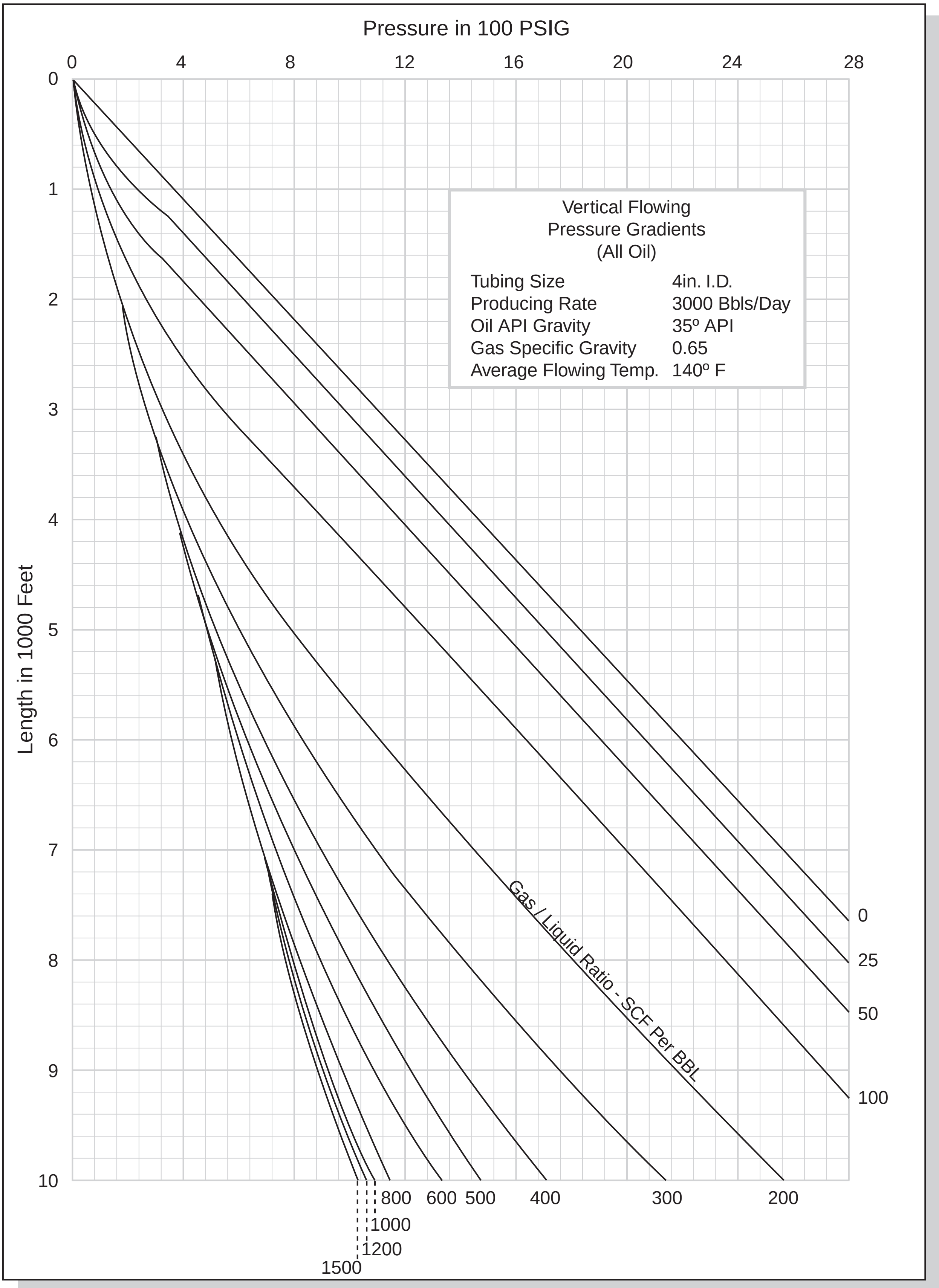
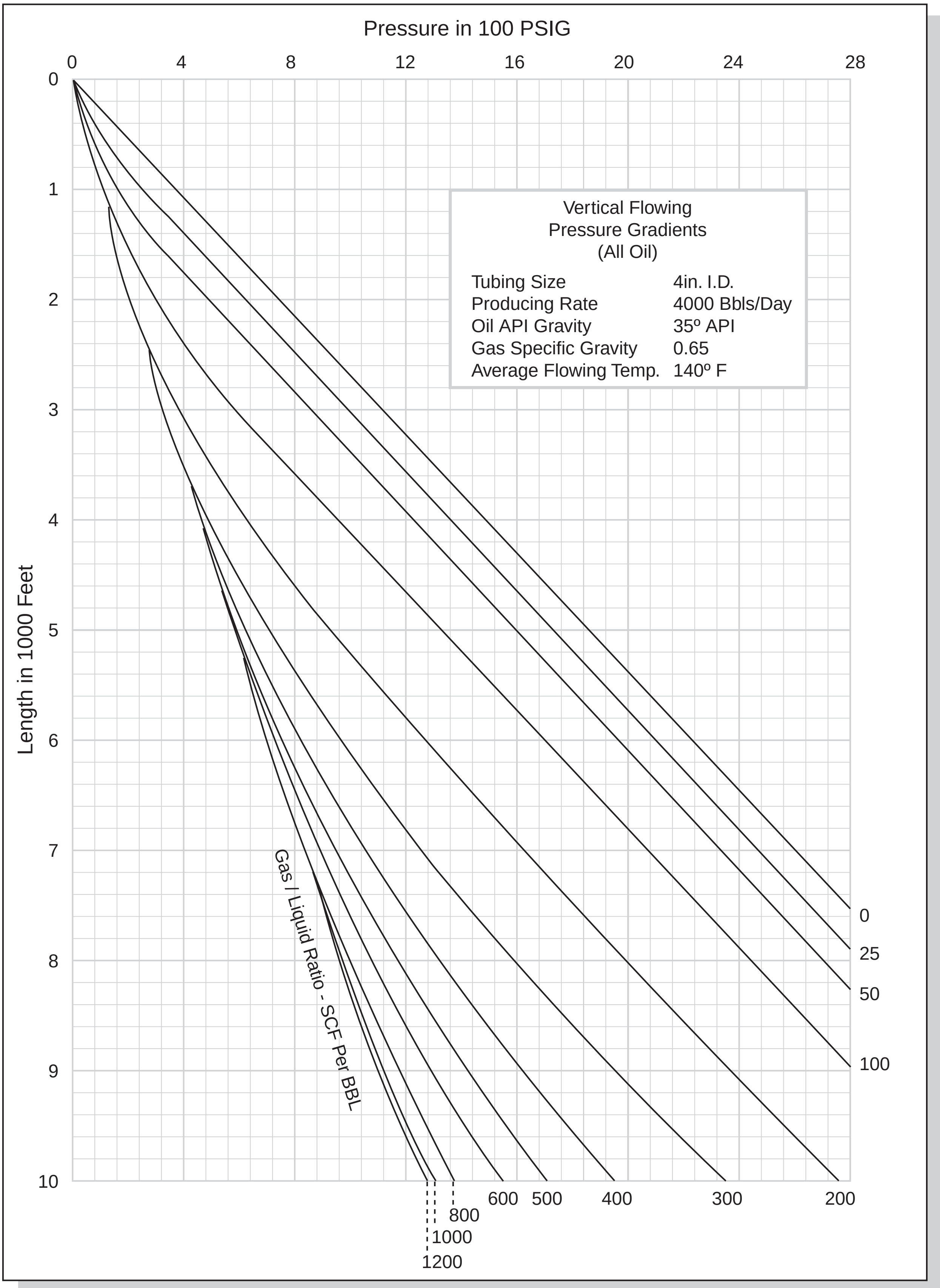

Pressure in 100 PSIG
0 4 8 12 16 20 24 28
Length in 1000 Feet
0 1 2 3 4 5 6 7 8 9 10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 3000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
800 600 500 400 300 200
1000
1200
1500

Figure 3


Pressure in 100 PSIG
0
4
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12
16
20
24
28
Length in 1000 Feet
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7
8
9
10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 4000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
200
300
400
500
600
800
1000
1200

Figure 4

Question 2

2(a)
Completion installation practices require a coordination of the equipment and the running procedures. Describe the preparations required prior to running tubing for

i) open hole completion
ii) cased hole completion.

[8]

2(b)
Once the downhole completion has been installed, describe the process of surface completion of a well and bringing it on production.

[12]

Question 3

3(a) List the 5 main technical disciplines that a Production Technologist needs to understand so that he/she can make a full contribution to reaching his Asset team's Objectives.

[4]

3(b) At which periods in the well's lifetime is input required from the Production Technologist?

[1]

3(c) What are the business drivers that guide the Production Technologist's actions with respect to capital investment, planning and operating cost budgeting?

[4]

3(d) Draw a simple sketch of the Composite Production System, indicating clearly the systems start and end points

[4]

3(e) Write one or two basic equations to quantify the "Total System Pressure Drop"

[4]

3(f) Wells producing from :

i) a solution gas drive reservoir and
ii) a water drive reservoir where there is a large aquifer present the Production Technologist with differing challenges when he manages the well's performance.

Draw a simple sketch to compare and contrast reservoir performance of these two drive mechanism types

[4]

3(g) For each of the above reservoir types, list 2 of the resulting Production Technology challenges that will control the well design and Production operations Policy.

[4]

Question 4

4(a) A recommendation is required to choose a perforating system for a completion in a formation
with a variable rock strength – ranging from a weak Unconfined Compressive Strength (C_f =
2,000 psi) to a strong value (C_f = 18000 psi).

Calculate the expected perforation lengths for the following perforating guns to be run in a 9.675 in. OD casing placed inside a 12.25 in. drilled hole.

Gun Type	API RP 43 Test Penetration
2 $^3/_8$ in. Wireline through tubing gun	6 in.
6 in. tubing conveyed perforating gun	33 in.

N.B. API RP 43 data available for these guns can be converted to downhole performance using the equation:

$$\mathbf{P_f = P_t * e^{0.086*(C_t - C_f)/1000}}$$

Where $\mathbf{P_f}$ is the expected penetration (inches) in formations with an Unconfined Compressive Strength, C_f (psi) and $\mathbf{P_t}$ is the API RP43 test penetration in the test formation (Unconfined Compressive Strength, C_t = 6,500 psi)

[4]

4(b) Drilling of the strong formation (C_f = 18000 psi) results in a hole with the same diameter as the drill bit. By contrast, drilling of the weak (C_f = 2000 psi) formation resulted in an enlarged hole (or "washout"). The hole diameter has increased by 8 inches.

Which perforating guns do you recommend and why?

[4]

4(c) A new drilling mud with a low leak-off rate is chosen for the weak formation. This mud creates a zone 2 in. deep around the wellbore of Formation Damage or reduced permeability (permeability is reduced to 5% of the original value). Also, a better quality hole is drilled. The washout (hole enlargement) is now only 3 in. greater than the drilled hole diameter.

Does this alter the perforating gun you recommend?
Explain the reasoning behind your answer.

[4]

4(d) Briefly list 4 major advantages & 3 disadvantages of using a tubing conveyed perforating system.

[9]

4(e) Briefly list 3 different techniques used to detonate a tubing conveyed perforating gun.

[4]

Question 5

5(a) Travel joints, sub-surface safety valves, side pocket mandrels, sliding side doors, perforated joints and landing nipples and among completion string components. Briefly explain them and their roles.

[6]

5(b) Tubing flow without annular seal is one of the options available for flow conduit selection. Describe the advantages and disadvantages of this technique (use sketches).

[4]

5(c) A well is drilled in an unconsolidated formation. Sand production is expected in particular after water breakthrough. The reservoir produced 15,000 bbl/day during DST with a drawdown of 500 psi. The reservoir and well data are as followings:

a. Oil gravity 35
b. Bottom hole temperature 100 °C
c. Top of the reservoir at 6500 ft
d. Thickness of the pay-zone 200 ft
e. GOR 500 SCF/bbl
f. H_2S=30 ppm
g. CO_2=1 mole%
h. Total Depth Drilled 6800 ft
i. Reservoir pressure=4500 psia
j. Bubble point pressure=3000 psia
k. K_v/K_h=0.15

Identify the available option for completion. What will you select for bottom hole completion and flow conduit and why?

[4]

After 2 years of production, the reservoir pressure has dropped to3500 psia and the water cut has increased to 30%, resulting in significant reduction in the well flow rate. Well test analysis shows that the aquifer is not very active and reservoir pressure drop is likely to continue. Suggest a workover strategy and justify your answer.

[3]

Was it possible to avoid/delay this workover by modifying initial tubing design? How?

[3]

Question 6

6(a) Describe the techniques and equipment used in measuring the length of wire and tension on the wire during wireline operations.

[6]

6(b) Describe Impression Block (tool), Wireline Bailers, and Wireline Spear and their applications.

[6]

6(c) An oil well is completed with 4.5” tubing (WEG at 6000 ft) and a 7” liner (6200-6700ft). The annular space is isolated by a permanent packer at 5800 ft. Production is through three sets of perforations (6300-6350 ft), (6420-6450 ft) and (6550-6600 ft). After few years of production the water-cut has increased to 50%, reducing the productivity of the well. A production logging has been planned to identify the water production zone (s).

The production logging tools have a maximum external diameter of 3.5”. Suggest steps taken prior to production logging.

[2]

If during initial examination an obstruction is detected in the tubing, what set of equipment do you recommend to identify the source of obstruction and why?

[2]

What steps do you recommend if the obstruction is due to wax deposition?

[2]

After removing the obstruction in the tubing, if sand is detected at the top of lower perforations (i.e., 6550 ft). Mention available options. What do you recommend?

(2)

Question 7

7(a) Describe the role of packers and their components (use sketches where necessary) and their various setting mechanisms.

[6]

7(b) Describe the available options for completion configuration in a dual zone reservoir (use sketches), assuming no fluid mixture. Mention their advantages and disadvantages.

[6]

7(c) Field “A” is an offshore field in approximately 1000 ft water. The exploration wells proved the existence two reservoirs with similar fluid compositions. The top of the two reservoirs have been identified at 6000 and 7500 ft.

Gas injection is required for achieving optimum production rate from both reservoirs. However, due low pressure rating of the top 1000 ft of the casing it is not possible to inject gas through annulus.

Your task is to develop an outline completion string for the oil production wells, producing from both reservoirs. It is necessary to have flexibility in selective production and/or stimulation of individual reservoirs. Identify key design features and the reasons for their selection.

[4]

Identify the components required for the completion configuration. Draw a sketch of your proposed completion configuration.

[4]

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8 Pages

NAME:
REGISTRATION NO.:
COURSE:
YEAR:
SIGNATURE:

Complete this section but do not seal until the examination is finished

Date:

Subject: Production Technology 1

INSTRUCTIONS TO CANDIDATES

1. Complete the sections above but do not seal until the examination is finished.
2. Insert in box on right the numbers of the questions attempted.
3. Start each question on a new page.
4. Rough working should be confined to left hand pages.
5. This book must be handed in entire with the top corner sealed.
6. Additional books must bear the name of the candidate, be sealed and be affixed to the first book by means of a tag provided

No.	Mk.

PLEASE READ EXAMINATION REGULATIONS ON BACK COVER

Answer 1

(1a)	Each of the phases, both gaseous and liquid, have individual properties
	such as density and viscosity which will be a function of pressure and
	temperature and hence of position in the well.
(1)	<u>Gas Liquid Mixtures</u>
	In the production of a reservoir containing oil and gas in solution, it is
	preferable to maintain the flowing bottom hole pressure above the
	bubble point so that single phase oil flows through the reservoir pore
	space.
	Consider such a case where oil flowing from the reservoir enters the
	production tubing. The flow of oil up the tubing and the associated
	pressure profile is illustrated in the Figure. The oil enters the tubing
at	
	a flowing pressure above the bubble point and hence no separate gas
	phase exists. The changing nature of the flow up the tubing can be
	considered in various stages from the base of the tubing.
(a)	Single phase liquid will occur in tubing whilst $P_{TUB} > P_{BUB}$. The
	pressure gradient is primarily influenced by the density of the liquid
	phase and is thus dominated by the hydrostatic head component of
	the pressure loss. Liquid expansion may contribute to a very slight
	reduction in liquid density and thence the hydrostatic gradient.
(b)	At the bubble point, the first gas is evolved which will:

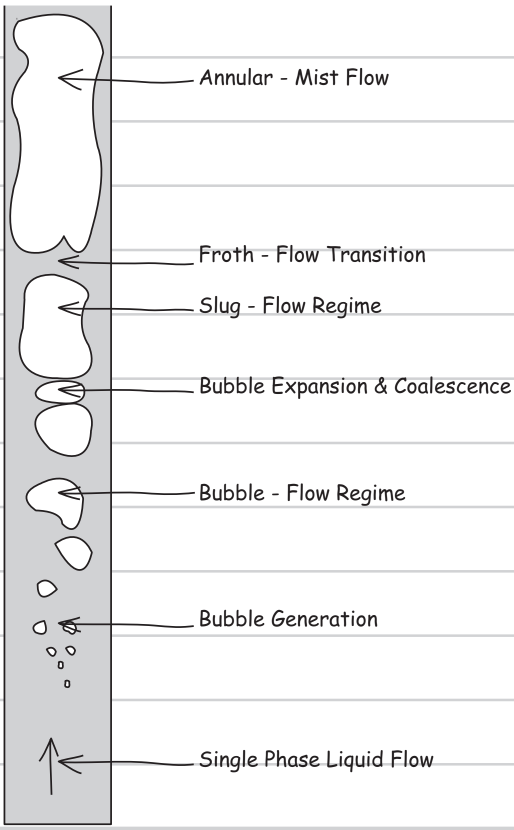
(i) Lower the average density of the fluids in the tubing

(ii) Increase the in-situ velocity

The gas is present in the form of discrete bubbles dispersed within continuous oil phase. The flow regime is termed "bubble flow" and the pressure gradient will decline provided the decrease in the hydrostaic head pressure loss exceeds the increase in the frictional pressure loss.

(c) With continued upwards flow, the pressure on the fluid declines. The decline in pressure on the fluid will cause:

(i) Expansion of the liquid phase



(ii) Evolution of additional gas components-increasingly heavier molecules-resulting in an increased mass of hydrocarbon in the gas phase. A simultaneous reduction of the mass of the liquid phase will accompany this mass transfer. the concentration of heavier components in both the gas and liquid phases would increase.

(iii) Expansion of the existing gas phase

This section of the tubing would demonstrate a continuously declining pressure gradient provided the decrease in the hydrostatic component exceeded the increasing frictional gradient

The above mechanisms will occur continuously as flow occurs up the tubing.

(d) As the flow continues higher up the tubing, the number and size of gas bubbles will increase until such a point that the fraction of the tubing volume occupied by gas is so large that it leads to bubble coalescence. The coalescence of bubbles will yield a "slug flow" regime characterised by the upward rise of slugs of gas segregated by continuous liquid columns. the upwards movement of the slugs will act as a major mechanism to lift oil to surface.

(e) Often, as velocity continues to increase in the slug flow regime, it may be possible that a froth type transitional flow occurs where both the oil and gas phases are mutually dispersed, i.e. niether is continuous.

(f) With continued upward movement, further gas expansion and liberation will occur, resulting in slug expansion and coalescence, leading to slug enlargement and eventually "annular flow". In annular flow, the gas flows up the centre of the tubing with oil flow occurring as a continuous film on the inside wall of the tubing.

(g) At extremely high velocities of the central gas column, shear at the gas-oil interface can lead to oil dispersion in the gas in the form of a "mist". This "mist flow" pattern will occur at very high flow velocities in the tubing and for systems with a high gas-oil ratio GOR.

It is possible that, as flow nears the surface, the increase in frictional pressure gradient exceeds the reduction in the hydrostatic pressure gradient and in such cases, the total pressure gradient in the tubing may start to increase.

(h) At very high flow velocities, the movement of liquid may occur predominantly as a mist of liquid particles compared to being an annular film.

These flow patterns have been observed by a number of investigators who have conducted experiments with air-water mixtures in visual flow columns.

(1b) i) The Productivity Index is described by

$$PI = \frac{q}{\overline{P}_r - P_{wf}}$$

$$P_{wf} = \overline{P}_r - \frac{q}{PI}$$

$$P_{wf} = 2700 - \frac{q}{2.3}$$

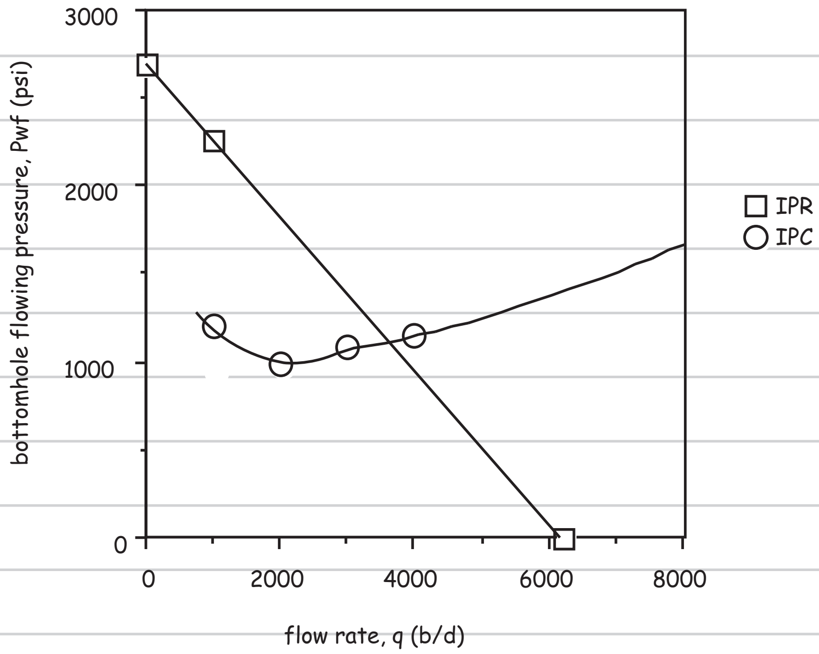
The Inflow Performance Relationship is developed by assuming several flow rates

flow rate, q	flowing bottomhole pressure, Pwf
0	2700
1000	2265
6210	0

ii) For the given tubing and fluid properties, assume various flow rates and calculate the flowing bottomhole pressure required to flow the fluid up the tubing at that particular flow rate. Try the following flow rates:

	Fig 1	Fig 2	Fig 3	Fig 4
flow rate, b/d	1000	2000	3000	4000
equivalent depth of top of tubing, ft	2700	2100	1800	1500
equivalent depth of bottom of tubing, ft	8700	8100	7800	7500
flowing bottomhole pressure, psi	1280	1000	1085	1160

The IPR and the IPC are plotted below



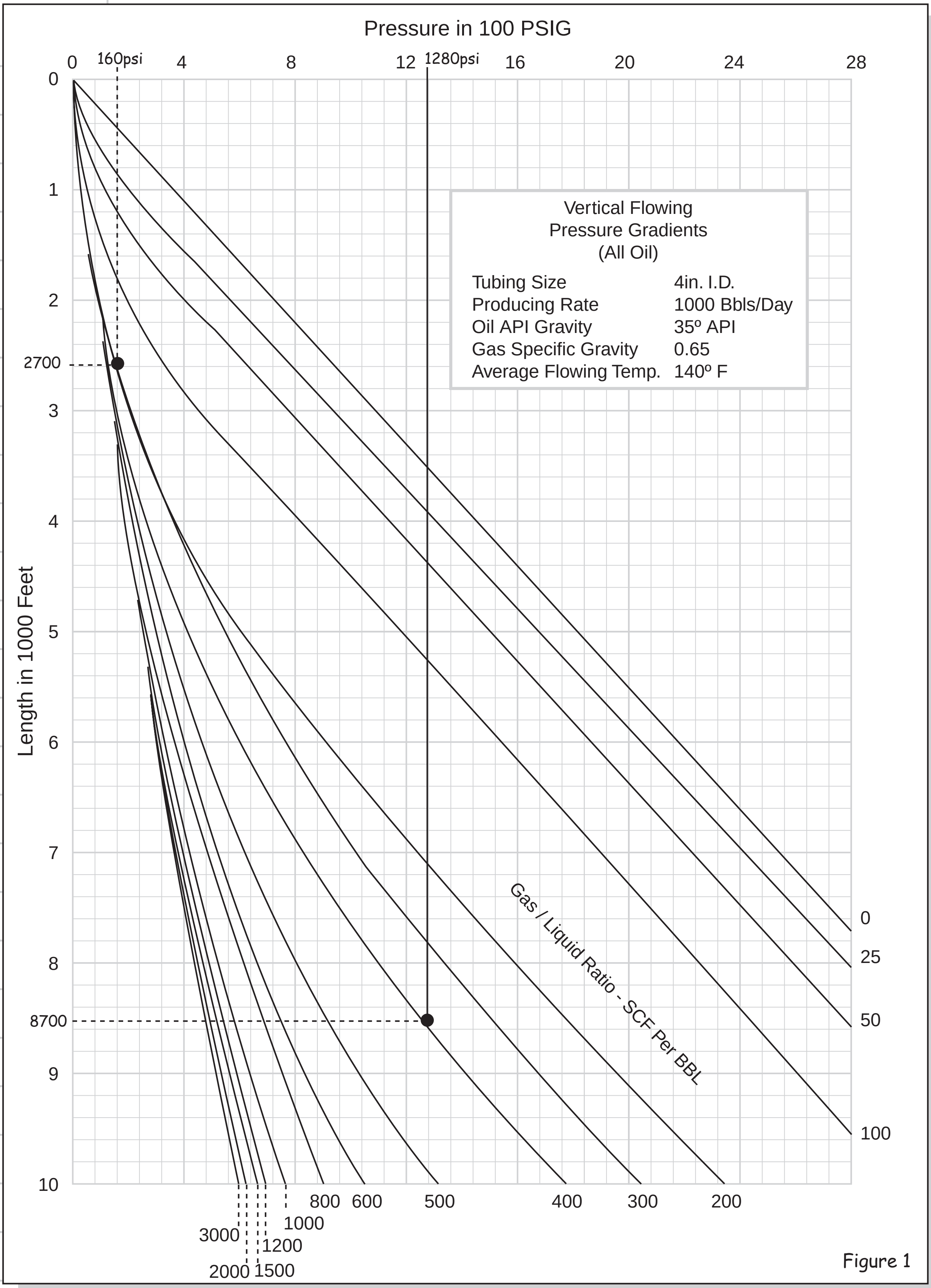
The operating point is where the two curves intersect: 3602b/d, 1134psi in the plot

Asa check:

$$P_{wf} = \overline{P}_r - \frac{q}{PI}$$

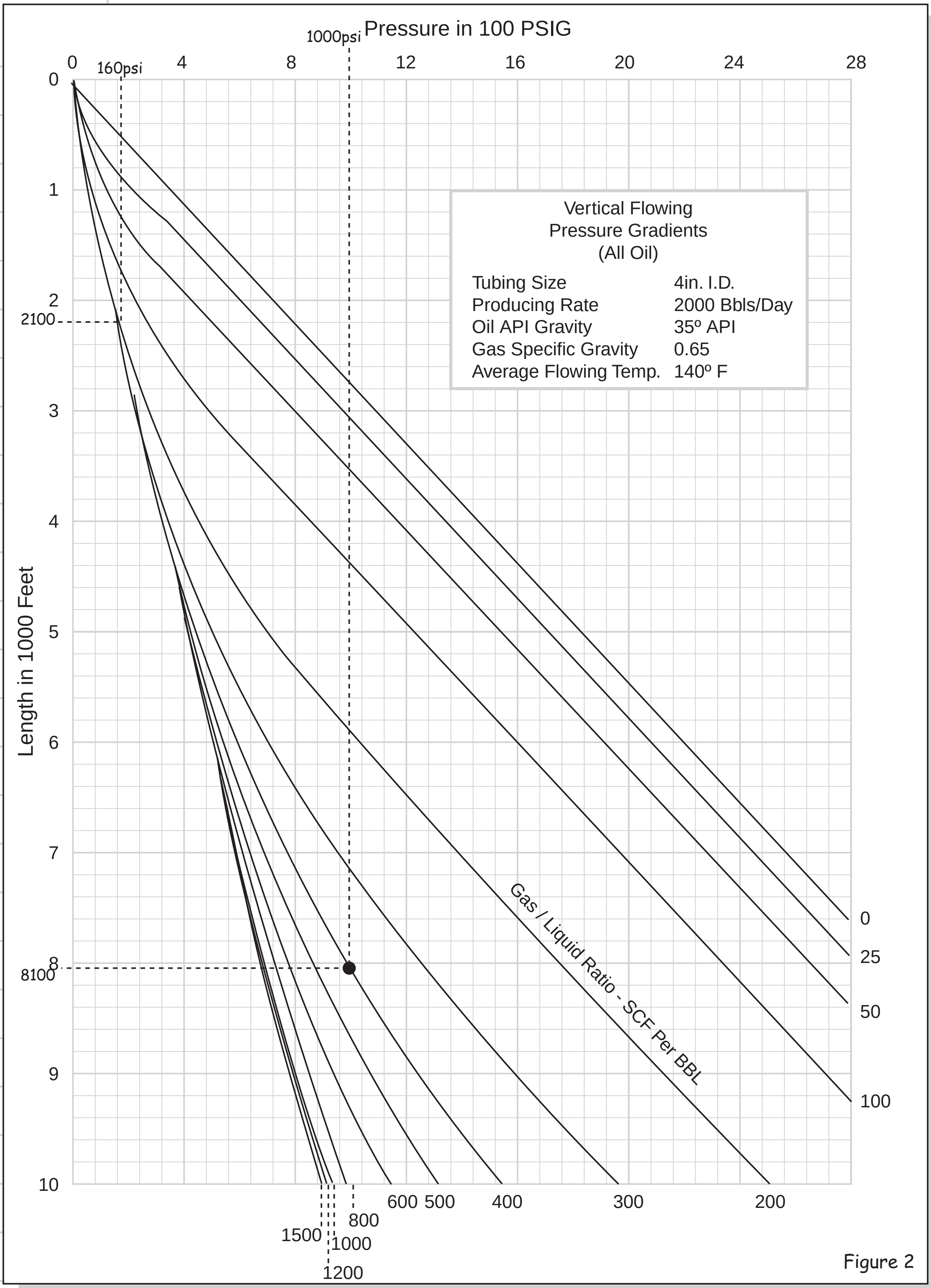
$$P_{wf} = 2700 - \frac{3602}{2.3}$$

= 1134psi



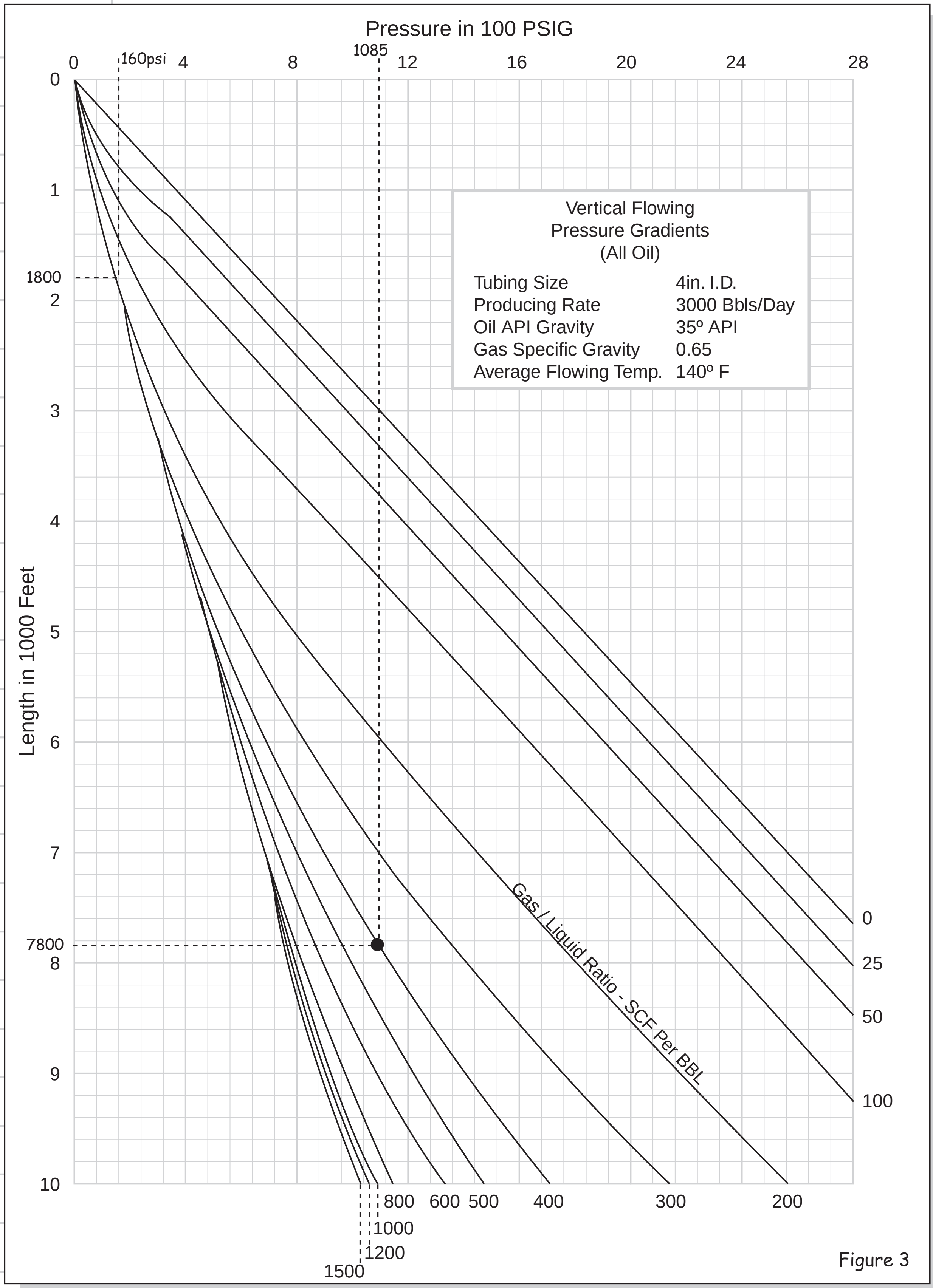
Pressure in 100 PSIG
0
160psi
4
8
12
1280psi
16
20
24
28
Length in 1000 Feet
0
1
2
2700
3
4
5
6
7
8
8700
9
10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 1000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
800
600
500
400
300
200
1000
3000
1200
2000
1500

Figure 1



Pressure in 100 PSIG
1000psi
0
160psi
4
8
12
16
20
24
28
0
1
2
2100
3
4
5
6
7
8
8100
9
10
Length in 1000 Feet
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 2000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
600 500
400
300
200
800
1500
1000
1200

Figure 2



Pressure in 100 PSIG
0
160psi
4
8
1085
12
16
20
24
28
Length in 1000 Feet
1800
7800
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 3000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
800
600
500
400
300
200
1000
1200
1500

Figure 3

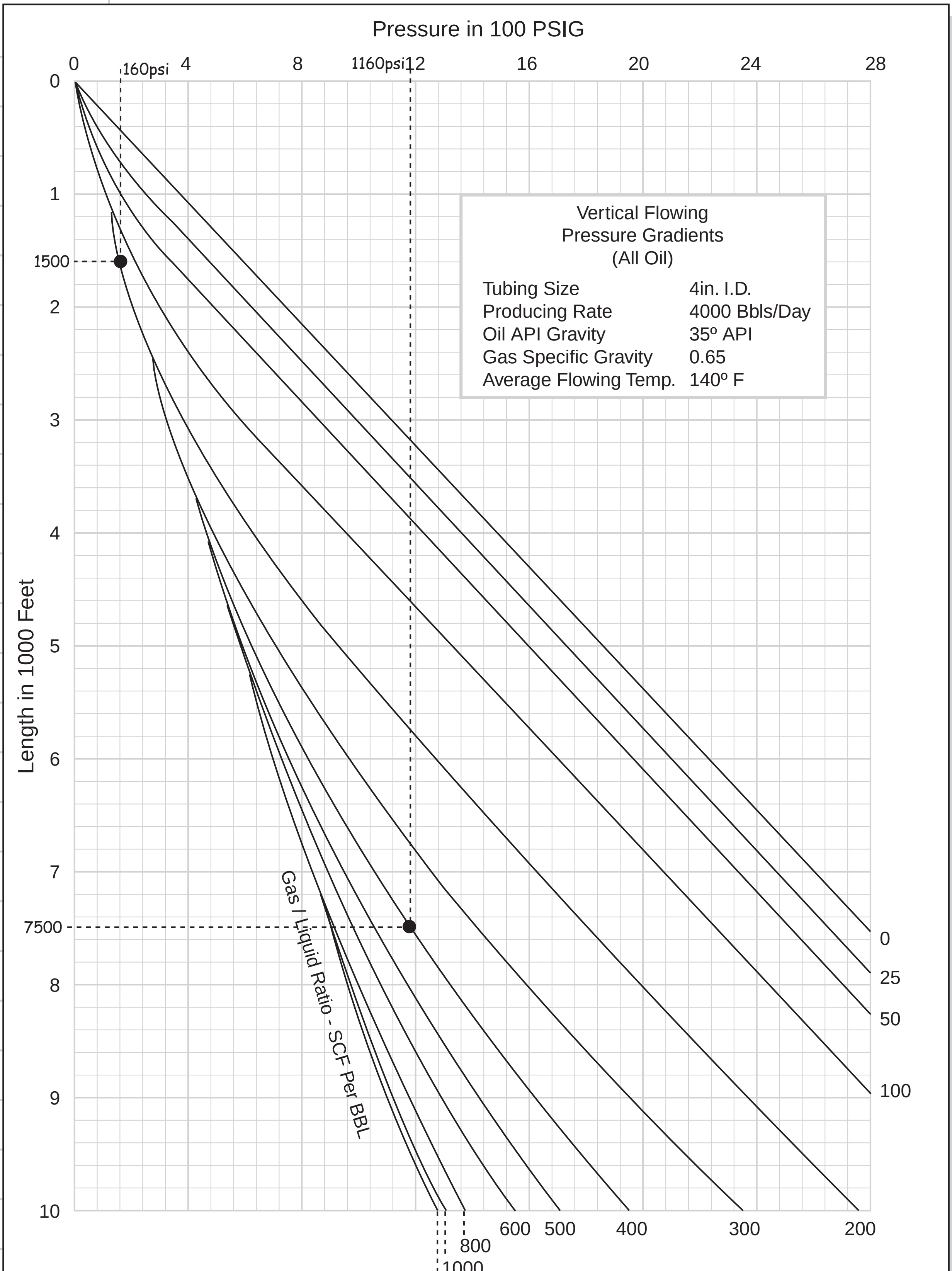

Pressure in 100 PSIG
0
160psi
4
8
1160psi
12
16
20
24
28
Length in 1000 Feet
0
1
1500
2
3
4
5
6
7
7500
8
9
10
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 4000 Bbls/Day
Oil API Gravity 35º API
Gas Specific Gravity 0.65
Average Flowing Temp. 140º F
Gas / Liquid Ratio - SCF Per BBL
0
25
50
100
200
300
400
500
600
800
1000
1200

Figure 4

Answer 2

(2a)	i) Open hole
	Ensure
	• Borehole free from drilled cuttings
	• Borehole is stable and not subject to continuous caving/collapse
	• Borehole contains the required fluid to allow effective completion of well
	• No obstructions internally in casing
	• Internal walls of casing are clean across proposed packer setting interval
	ii) Cased hole
	• Downhole logging suite available to allow depth correlation between formation intervals and location of couplings
	• Identify the location of the top of the cement shoetrack and dress the TOC as required
	• (No obstructions exist internally in casing – as per openhole)
	• Internal walls of casing are clean across the proposed packer setting interval (as per openhole)
	• Wellbore contains required completion fluid in good condition
(2b)	
	Surface completion:
	• Install back pressure valave in tubing hanger
	• Remove BOP stack
	• Install control line inlet flange/ adaptor spool
	• Connect control line and pressure test to SSSv
	• Install Xmas tree

- Pressure test tubing seals and Xmas tree
- Connect flow lines and pressure test connection to Xmas tree
- Remove Back pressure valve
- Install tree cap

Production start up

- Place required fluid in annulus for long term protection, in tubing for hydrostatic drawdown or balance pressure conditions
- If the well hasn't been perforated, install and pressure test wireline lubricator to allow subsequent fluid circulation with a positive tubing head pressure
- Open the circulating device and displace annulus/tubing to required fluids (normally packer fluid in annulus will act as kill fluid while tubing fluid will underbalance. At end of circulation there will be a positive THP. This can be reduced in unperforated well to produce the required drawdown differential between bottomhole and reservoir pressures.
- For preperforated wells, well can be opened for production, in case of unperforated wells, perforating operation can be conducted
- Well opened up initially to achieve stable flow rate and monitor performance, then beaned up to operating flow rate over a few days

Answer 3

(3a) The Production Technologist requires a full understanding of the physical & chemical characteristics of the production system. The main Production Technology technical disciplines are:

(1) Production Engineering:

- Fluid flow in well
- Reservoir dynamics
- Equipment design, installation, operation & fault diagnosis

(2) Production Chemistry:

- The Fluids (produced, injected and treatment fluids)
- The Formation (mineralogy, physical/chemical properties, rock strength and response to fluid flow).

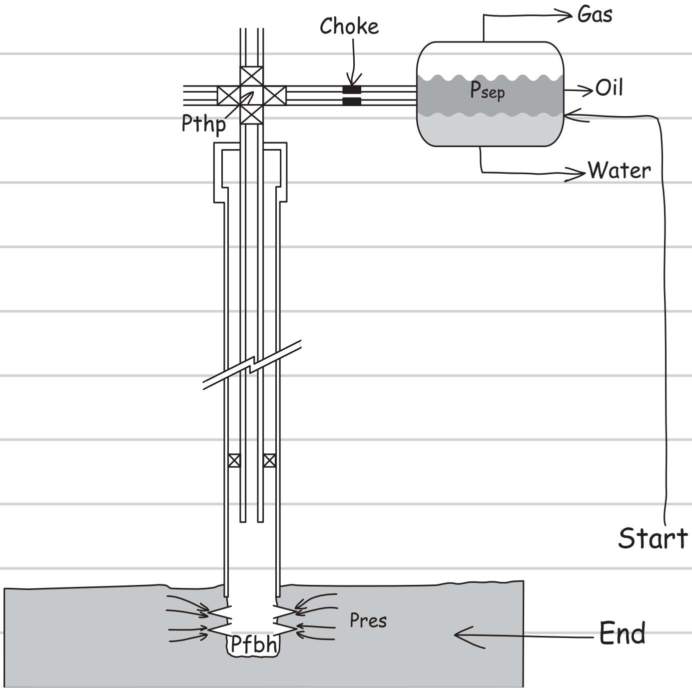
(3b) The Production Technologist is involved at all stages from conceptual well design to well abandonment

(3c) The Production technologist aims to: ***"Minimise total lifetime costs commensurate with maximum recovery of reserves"***

(A) **Cashflow** - Maximise both cashflow and reserves:
Maximise (i) production rates + (ii) economic longevity & (iii) minimise down time,

(B) **Costs** - includes both fixed (Capital) and Operating costs: The latter is a sum of *Fixed* costs (associated with the operation) & *Direct or variable* costs associated with the level of production and the nature of the operating conditions.

(3d)



(3e)

$$\Delta P_{TOT} = [\Delta P_{RES} + \Delta P_{BHC} + \Delta P_{VL} + \Delta P_{SURF} + \Delta P_{CHOKE}]_Q$$
$$\Delta P_{VL} = \Delta P_{FRICT} + \Delta P_{HHD} + \Delta_{KE}$$

(3f)

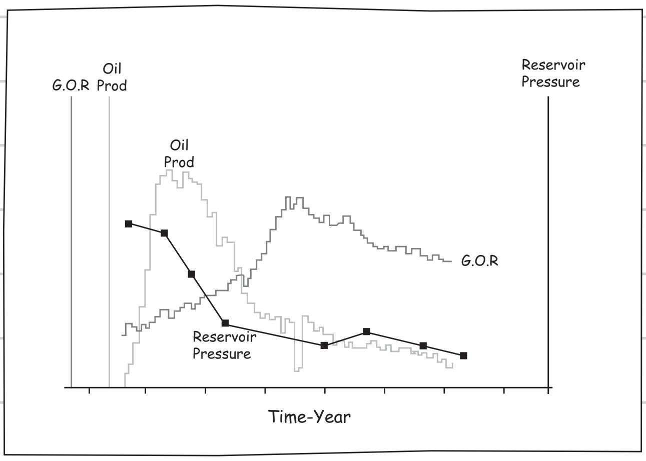


Figure 2 Performance of a *solution gas drive reservoir*

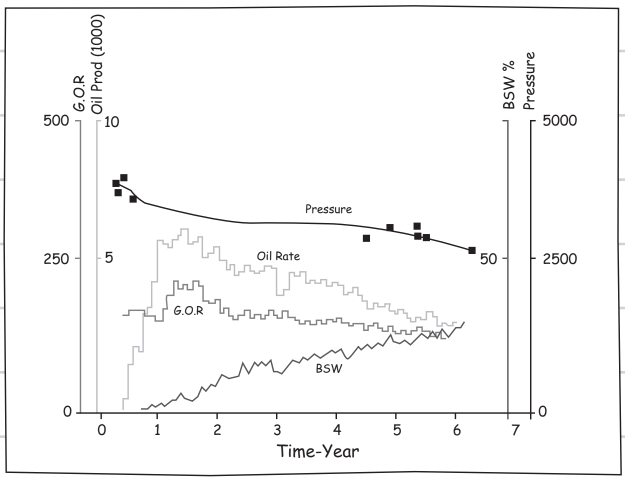


Figure 6 Performance of a well with *water drive*

(3g)

Solution Gas Drive Reservoir

- Pressure declines rapidly – early introduction of artificial lift
- GOR increases and gas cap forms – maintain completion zone in the oil rim so as to minimize gas production & conserve reservoir energy

Water Drive Reservoir with large Aquifer

- Pressure remains high – delaying need for artificial lift installation (wells may even continue to flow naturally if the reservoir is sufficiently overpressured)
- Level of Aquifer Water rised as oil is produced - maintain completion zone in the oil zone so as to minimize water production

Answer 4

(4a)

Perforation Penetration (in)			
Perforating Gun	Formation Unconfined Compressive Strength (psi)		
	6500	2000	18000
Wireline Through tubing	6	8.8	2.2
Tubing Conveyed	33	48.6	12.3

(4b)

The penetration achieved by the thru-tubing gun (5.8in) is similar to the cement depth of the drilling wash-out (5.3in). In the strong formation the perforation will only penetrate less than 2 in beyond the cement.

The tubing conveyed perforator is recommended since this is the only gun which will penetrate to the weaker, washed out (probably more permeable) formations.

(4c) The total depth (3.5 in) of the extra cement in the washout (1.5 in.4) and the formation damage (2 in.) is marginally less than the perforation penetration (5.8 in.). This makes the W/L gun more acceptable. However, the casing may be eccentrically placed in the washout, making the W/L gun unacceptable.

(4d)

The advantages of tubing conveyed guns are:

(1) The ability to use high shot densities and to create large entrance hole sizes can lead to reduced hydraulic erosion in the formation around the perforations. This allows higher flowrates to be realised without formation breakdown.

(2) The perforating operation can be completed in one run even for long intervals. Intervals in excess of 1000 m have been shot in one run with TCP.

(3) Unlike wireline operations, even if the interval is fairly large, the ability to shoot the interval with one gun means that all the perforations are created simultaneously, which benefits well clean up and productivity.

(4) As with the through tubing techniques the well is not perforated until the well is completed and it is safe to allow well fluids to enter the wellbore.

(5) With wireline conveyed guns, whilst perforating under drawdown, there is a danger that the guns will be damaged or blown up the wellbore if too high a pressure drawdown is used. With TCP, the durability of the system allows high differential pressures, e.g. >2500 psi, to be used.

(6) If the hydromechanical firing option is used the technique is feasible, even in highly deviated wells, as there is no dependence on wireline.

(7) If either the mechanical or hydromechanical firing system is used there is no necessity for radio silence.

The disadvantages of TCP are:

(1) If a misfire occurs, then gun retrieval will require a round trip which is both time consuming and costly. There is also a safety concern as to why the gun has not detonated. Detonation whilst the string is being retrieved, although rare, has occurred.

(2) If the gun is not detached but is to remain opposite the perforated interval, it will prevent production logging or through tubing wireline below the tailpipe.

(3) Since the running procedure for the guns is prolonged, the charges may be exposed to well temperatures for an extended period and this may lead to degradation.

(4) In general, the costs of TCP are higher than conventional wireline perforating. The cost differential will decrease as the length of interval to be perforated increases. Further, if the gun is to be dropped into the sump the cost of drilling the additional sump length must be considered.

(5)	Surface observation of the degree to which the charges have fired is not possible unless the gun is retrieved.
(4e)	(i) Mechanical
	(ii) Hydromechanical
	(iii) Wire Line

Answer 5

(5a) **Travel joint:** This device consists of two concentric cylinders with elastomer seals between them. The outer and inner cylinders are attached to the tubing. They accommodate any change in the tubing length due to any variation in system conditions. The length of travel joint is normally 20 - 60 ft but can be varied to suit the particular requirements.

Sub-Surface Safety Valves (SSSV): Their function is to provide remote sub-surface isolation in the event of a catastrophic failure of the Xmas tree or as a failsafe shutdown system.

Side Pocket Mandrels (SPM): This component, contains an off-centre pocket with ports into the annulus. Using wireline or coiled tubing, a valve can be installed in the packer which allows fluid flow between tubing and annulus, e.g.: Gas Lift Valves, Chemical Injection Valves and Circulation

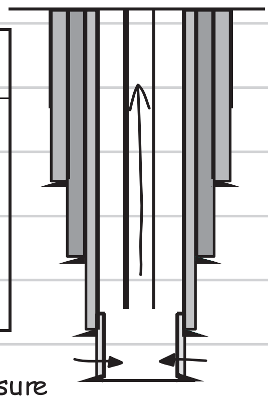
Sliding Side Doors (SSD): This device permits communication between tubing and annulus. It consists of two concentric sleeves with elastomeric seals between them and each with slots or holes. Using wireline or coiled tubing, the inner sleeve can be moved upwards or downwards to align the openings on both sleeves. Its application is for well killing and placement of fluids in the tubing or annulus by circulation.

Perforated Joints: It is a perforated tubing section which allows for flow to enter the string even if the base of the tubing string is plugged by, say, pressure gauges.

Landing Nipples: A landing nipple is a short tubular device which has an internally machined profile, capable of accommodating and securing a mandrel run into its bore on wireline or coiled tubing. The nipple provides a recess to mechanically lock the mandrel in place using a set of expandable keys a pressure seal against the internal bore of the nipple and the outer surface of the mandrel.

(5b)

Advantages	Disadvantages
Cost of packer and rig time Simplicity Ease of circulation Kick-off Gas lift	Casing exposure to high pressure Corrosion Annulus heading



Casing exposure

(5c) The available options are:

Slotted liner or gravel pack for bottom hole completion to prevent/minimise sand production

Tubing flow with annular isolation to prevent/minimise the risk of corrosion damage to the casing.

If necessary the water producing sections should be closed. Artificial lift (gas lift or ESP) should be installed.

Perhaps. Provisions for gas lift valves could have been considered during the initial completion. Also if water production is from the lower part of the formation, it might have been possible to cement that section and delay the workover by plugging the water producing zone.

Gauge cutter should be run to identify the depth and diameter available for the operation.

Answer 6

(6a) The length of cable used and accordingly the depth of the tool string with reference to a datum point e.g. the tubing hanger in the wellhead, is measured by allowing the cable to be held without slippage against a hardened wheel or odometer. The actual depth of the equipment depends on cable's expansion or contraction in the wellbore. Depth correlation is required for accurate depth measurements.

Weight indicator is used to measure the tension. The cable tension is continuously monitored to ensure that the breaking strength of the cable is not exceeded.

(6b) **Impression tool:** A lead impression block has a lead filled core at its base and when lowered on to the fish will provide an imprint of the physical condition of the top of the fish. They are used to identify the type of fish and/or availability of the fishing neck prior to a fishing operation.

Wireline spear: The wireline in normally expected to break at the rope socket during normal failure such that the wireline itself can be pulled from the hole. In the event that the wireline breaks at a different location, the wire may form a 'birds nest' in the tubing which will need to be removed by a grapple known as a wireline spear.

Wireline bailer: The build up of solid deposits e.g. sand in the wellbore or perhaps the deposition of solids on top of a tubular component such as a mandrel, may necessitate the use of bailers.

Particularly in the latter case it may be necessary to remove the solids prior to gaining access to the pulling neck of the mandrel. A bailer can be run on a wireline tool string. Two general types are available, the first is operated by jarring up and down on a piston bailer which acts to suck sand into the bailer. The other design known as a hydraulic bailer, comprises a chamber at atmospheric pressure, a shear disc and non-return ball valve. Downwards jarring on the solids will shear the disc and the solids will be sucked up into the low pressure chamber.

(6c) Gauge cutter should be run to identify the depth and diameter available for the operation.

Impression block could give an imprint of the top of the obstruction which could be helpful in identifying the obstruction.

Some of the available options are:

1. Mechanical removal (e.g., bailer, gauge cutter)
2. Solvent (using coiled tubing or dump bailers)
3. Hot oiling (coiled tubing)

- It may not be necessary to remove the sand. For sand removal various techniques, including coiled tubing, wireline bailers, and in some countries flowing the well for clean up could be used.

Answer 7

(7a) Packers provide physical isolation of the casing/tubing annulus above the production zone or isolating various production zones.

Their components consists of: Sealing elements, Slip system, and Hold Down Buttons.

Their setting mechanisms are: Weight set, Roto-mechanical set, Electric wireline set, and Hydraulic set.

(7b) **Casing/Tubing Flow:** One zone is produced from casing and one zone from tubing.

Advantages: Simple, cost effective

Disadvantages: Corrosion, erosion in the casing. Annular safety valve, Pressure limitation in reservoir stimulation. Potential fluid segregation and high pressure drop.

Dual Tubing Flow: Each zone is produced through individual tubing.

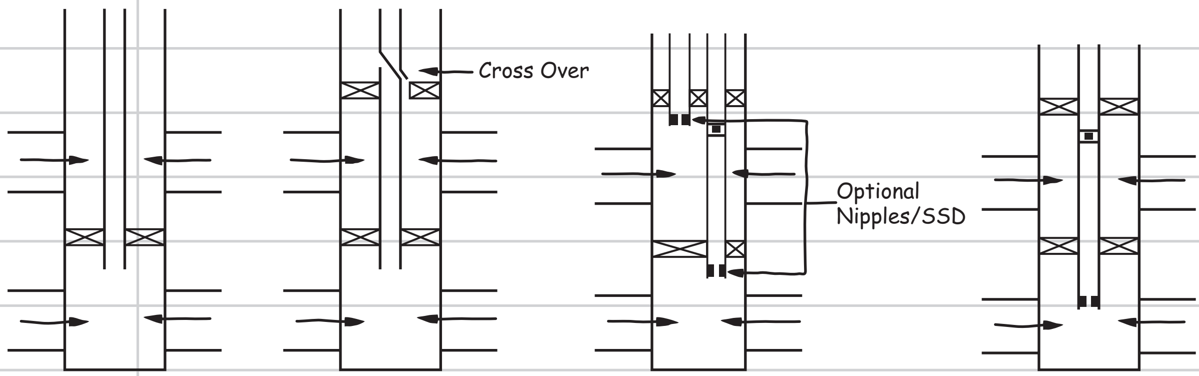
Advantages: Better control, potentially lower pressure drop, reducing the risk of corrosion and erosion.

Disadvantages: Cost, complexity

Single String Selective Producer: One tubing is run and is used for alternate production from the two zones:

Advantages: Relative simplicity, cost

Disadvantages: Lower production rate from the well.

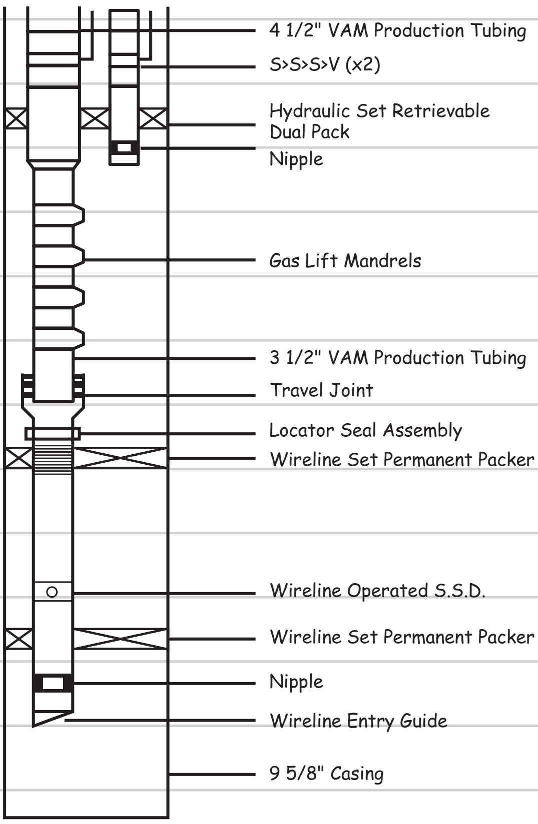


Upper Zone/Annular Flow Lower Zone/Annular Flow Single String Selective

- Because the oils from the two reservoirs are very similar the best option is to go for co-mingled flow. It is possible to set the packer above the two reservoirs and perforate and flow the two reservoirs through a single tubing. However, there won't be any flexibility in fluid

(7c)
- The necessary components are identified in the figure below. production or reservoir stimulation. The best option is to use two packers and a combination of SSD and wireline plugs for isolating the individual reservoirs.

- To prevent casing exposure to high injection gas pressure, it is possible to install a separate tubing/packer combination for gas injection.


4 1/2" VAM Production Tubing
S>S>S>V (x2)
Hydraulic Set Retrievable Dual Pack
Nipple
Gas Lift Mandrels
3 1/2" VAM Production Tubing
Travel Joint
Locator Seal Assembly
Wireline Set Permanent Packer
Wireline Operated S.S.D.
Wireline Set Permanent Packer
Nipple
Wireline Entry Guide
9 5/8" Casing

Course:- 28117
Class:- 289033a

HERIOT-WATT UNIVERSITY
DEPARTMENT OF PETROLEUM ENGINEERING

Examination for the Degree of
MEng in Petroleum Engineering

Production Technology 1a

Thursday 22nd April 1999
09.30 - 11.30

NOTES FOR CANDIDATES

1. This is a Closed Book Examination and candidates are allowed to utilise course notes for reference during the exam.

2. 15 minutes reading time is provided from 09.15 - 09.30.

3. Examination Papers will be marked anonymously. See separate instructions for completion of Script Book front covers and attachment of loose pages. Do not write your name on any loose pages which are submitted as part of your answer.

4. Candidates should attempt ALL questions.

5. The marks allocated to each question are shown in brackets after the question.

6. State clearly any and all assumptions you make.

The Alpha oil reservoir is a small offshore field which is currently being considered for development. It is likely that the field will require 3-5 production wells. Currently the use of a small fixed jacket is preferred with the possible use of a subsea template/completion if further delineation causes a significant downsizing in reserves.

The general conditions for the field are shown in Table 1 with the fluid and reservoir characteristics shown in Table 2 and 3 respectively. A projected casing schedule is shown in Table 4. Table 5 outlines the probable trajectories.

It is anticipated that the well deliverability will require the use of $4^1/_2$" OD tubing. However as the wells are anticipated to be under a depletion (solution gas in late life) drive, well deliverability will decline almost immediately.

Table 1 - Field Location and General Data

Water depth	180 ft
Location	100 miles offshore NE Scotland
Adjacent existing platform is	8 miles to the SW
No. of wells projected	3-5
Reserve estimate	47 x 10^6 STB
No aquifer	
No gas cap at initial reservoir pressure	

Table 2 - Reservoir Fluid Data

API Gravity = 31 degrees
Oil viscosity at reservoir conditions = 7 cp
GOR = 420 SCF/bbl
H2S concentration = 5ppm
CO2 concentration = 8%
Bubble point of crude oil = 1800 psia

Table 3 - Reservoir Data

Top of oil column = 5900 ft TVDSS
Thickness of reservoir sand = 140 ft
Bottom hole temperature = 180°F
Permeability = 80-270 md
Average permeability = 170md
Initial reservoir pressure = 2900 psia at 5900ft
KV/KH = 1.0 (approx)

The reservoir consists of a consolidated to friable, heterogeneous, fine grained sandstone with limited clay content. It is slightly overpressured and overlain by a thin (150 ft) shale layer.

Table 4 - Provisional Casing Schedule

Hole Size in		Casing Size in	Setting Depth (TVDSS) ft From	To
26		20	Surface	1000
17 $^{1}/_{2}$		13 $^{3}/_{8}$	Surface	2600
12 $^{1}/_{4}$		9 $^{5}/_{8}$	Surface	4700
8 $^{1}/_{2}$		7	4200	5950
6	option 1.	4 $^{1}/_{2}$	5500	6150
	option 2.	4 premium screen		
	option 3.	Open hole		

Table 5 - Projected Well Trajectory

All wells will have the following outline trajectory

Hole Size in	Hole angle from vertical in section Top	Bottom
26	0º	0º
17 $^{1}/_{2}$	0º	15-25º
12 $^{1}/_{4}$	15-25º	60-65º
8 $^{1}/_{2}$	60-65º	65-80º
6	65-80º	80-90º

Use short notes and sketches to answer the following questions.
State all assumptions and give reasons where possible.

1. For this particular development, discuss the options for the bottomhole completion technique, namely, perforated/cemented liner; premium screen or openhole. What would you recommend and why?

[15]

2. What would be your concerns about the selection of a drill-in fluid for the 6 inch hole and what fluid and additives would you recommend?

[10]

3. Provide a sketch of a conceptual configuration for the completion of the oil producers. Specify:

   a) Key components and your reasons for their selection

   b) Approximate setting depths

[25]

4. Assuming that the wells were drilled overbalanced how would you lower the bottomhole pressure to initiate flow?

[10]

5. If it is necessary to pull the tubing, how would you secure the well, isolate flow and kill the well?

[10]

6. If the reserves are downgraded and a platform is uneconomic, how would you modify your design if the field were developed by a maximum of 3 subsea satellite production wells? Provide a sketch.

[15]

7. Propose a contingency configuration for satellite water injector completions.

[10]

8. If the reservoir were put on water injection, how would this impact on your design for the oil producers?

[5]

End of Paper