- Mechanical removal by drilling or erosion with a slurry with beads if the scale coats the inside of the tubing. Re-perforating can replace blocked perforations.

- **Waxes (paraffins)**
  - The wax is normally kept in solution in the crude oil by ensuring that the temperature is maintained above the cloud point at all times. This involves the insulation of flow lines, tanks, etc. as well as the use of heaters where appropriate. Heated crude oil tankers are used for sea or road transport.

  Accurate modelling of the temperature distribution in the wells and facilities needs to be performed to ensure that the minimum temperature that prevents wax forming at the coldest point in the flow system is maintained at all times. This is particularly important for deep subsea wells where long flow lines between the wellhead and the surface facility are exposed to seawater temperatures of a few degrees ^{o}C. *One of the major problems with wax and other scales or hydrates is a system shutdown. It is important to replace the production fluids, or inhibit them in the lines when the production for some reason is stopped and the lines can cool down while also possibly being at high pressure.*

  It is quite common that scaling starts at surface and then propagates downhole with production time as the low wellbore pressure and temperature conditions, promoting scaling, move deeper down the well. As mentioned, proper modelling of the temperature distribution in the wells and facilities needs to be performed to ensure that this minimum temperature is maintained at all times.

  - The rate of agglomeration of the wax crystals can also be reduced by the addition of an inhibitor (pour point depressant): once again kinetics of the precipitation process can be influenced, not the thermodynamics.

  - Wax in production facilities can be removed by mechanical scraping (e.g. using paraffin scrapers a.k.a. paraffin knives during wireline well servicing).

  - Wax deposits in the formation, tubing and surface facilities can be dissolved in hot stock tank crude oil (cheap and readily available) a.k.a. 'hot oiling' or with solvents (e.g. aromatic solvents that are more expensive, but can dissolve a higher concentration of wax).

- **Asphaltenes:**
  - Solid asphaltene is normally removed mechanically from the well and facilities.

  - A range of commercial solvents are now also available (e.g. aromatic solvents with alcohols).

- **Gas hydrates (or clathrates):**

Hydrates are ice-like solids forming in the presence of gas and water at high pressures and low temperatures. Water molecules form a structure around a gas molecule (e.g. methane, ethane, propane, or CO_2). The hydrate formation favourable conditions normally happen at the surface facilities (especially around restrictions, in shut-down pipelines or wells, etc.), seldom in the tubing or annulus.

Hydrates can block the tubing or flowline.

- Continuous inhibition of hydrates by e.g. methanol and other alcohols or glycol, especially in the wells and lines prior to shut down, is common. Low Dosage Hydrate Inhibitors (LDHI) can also be used such as surfactants, anti-agglomerates, etc.
- Thermal insulation and heating of the lines can prevent hydrates forming conditions.
- Dehydration of gas, either exported or used in gas lift (as discussed earlier in this course) is a standard practice.
- If a hydrate plug has formed in the well, depressurisation (at surface) can be dangerous as the plug can start moving as a projectile since the wellbore pressure below the plug is high. Injecting e.g. glycol from surface to equalize pressure, and to gradually dissolve the plug while reducing the wellbore pressure is an option.

There are many more, less common formation damage and flow assurance problems (e.g. naphtenates, elemental sulphur, etc.) that are beyond the scope of this course.

A good summary of the common types of damage is provided in Appendix A.

7. APPENDIX A (NOT EXAMINABLE)

Appendix A is a summary of common types of formation damage, diagnostic clues and remediation techniques from "An Introduction to the Basis of Well Completions Stimulations and Workovers" (2nd. edition), courtesy of George King (Tulsa, 1996).

coning of water	onset of water production after extended production; formation has no vertical permeability barriers and sufficient vertical perm to allow water to move toward drawdown	limit rate, some treatments may temporarily be useful; most water control products are not useful without natural reservoir barriers
commingled water production	initial production of water with oil in primary, with breakthrough in flood; water cut increases in flood	no treatment or temporary at best
waterflood breakthrough through high permeability zone	examine produced water analysis and compare with flood water	high permeability zones should be plugged deep (d > 100') from producer and injector when oil recovery from zone is complete
micro porosity	caused by some forms of clay; may bind water and make high Sw readings on log	no treatment necessary
emulsion	unstable emulsions, breaks on standing; created in tubing at pressure drop points in piping system from pumps to choke	no down hole treatment suggested; treat on surface if string redesign is impractical
stabilized emulsion	very stable emulsion, partially wetted fines at interface; common after drilling mud dispersal or cleanup of mud or cement fines by acid; may also occur on polymer cleanup; common in production form unconsolidated formations, especially after acid or gravel packing operations	treat with mutual solvent and acid; remove downhole source of solids if possible
oil base mud emulsion damage	very common in wells drilled with oil base mud; if treated with acid or brine before the sulfonate emulsifiers are washed off the cuttings by production or solvent treatments, an emulsion from that can lock up the well; the first one or two treatments may be short lived as more mud and mud filtrate moves back toward the wellbore, this is often the case in naturally fractured formations	wash with aromatic solvent followed by mutual solvent and acid; may require several treatments; cuttings removal is important
surfactant stabilized emulsion	stable to very stable emulsion; common to severe after acid treatment; may be able to see the stabilized skin at the drop interface	treat on surface if temporary; use mutual solvent or surfactant to prevent emulsion with next acid job
sludge	sludge is an emulsion that is nearly solid; it may be triggered by acid, oil based mud, asphaltenes, or iron compounds; disperse the sludge in xylene and analyze for components, particularly iron	prevention is best cure; use non sludging acid systems, test with iron content expected in well
paraffin / wax	Forms in tubing near surface as oil cools and cloud point is reached; may become increasingly a problem as field ages; most paraffin deposits melt at < 150°F. Often form at pressure restriction in tubulars; soft to hard mass found at press drops; color reddish brown to black; even white or gray possible;	scraping, cutting for mechanical removal; hot oil useful if deposit is < 100 ft from surface; solvent soaks on deeper deposits; some inhibitors available for pipelines and few problem wells; some wells require continuous downhole treatment through macaroni string; special bacteria are also used to prevent precipitation

Type of Damage	Diagnostic Clues	Remedial
hydrates (ice)	gas well, intermittent flow, near total shutoff, followed by return to flow in a few minutes; produces a small amount of water	glycol or alcohol injection below hydrate formation point. Insulated risers or tubing.
	oil well, usually only forms near mud line in arctic regions; may also form in drilling mud	insulated risers
migrating fines	kaolinite or fibrous illite clay or some feldspars (non clays); brine salinity changes may trigger fines movement; sporadic reductions in flow rate, variable production rate tests; fines in prod, emulsions rare but possible	clay control for prevention, retarded acid for removal; may need to limit rate in extreme case
swelling clay	smectite clay, sometimes illite and smectite interbedded clay; permeability is sensitive to change in water salinity or brine type	acidize with HCl/HF if damage is shallow Hydraulic Fracture if damage is deeper than 12"
water blocks	usually gas well, small pore throats, untreated water, low pressure formation; if very low pressure (< about 0.2 psi/ft), pore throat size doesn't matter	matrix treat with alcohol or surface tension lowering surfactant; inject gas in gas reservoir to distance of 10 ft
poor load fluid recovery	usually formation dependent; may decrease production rate in severe cases or cause long cleanup time. Most common in formations with small pores and microporous clays	Prevention - avoid or minimize water contact and lower surface tension of water. Removal - alcohols and some surfactants
fill in perforations	high skin, can inject into well at very low rates; reperforating may show sharp increases	cleanout of reperforate
fill in casing	high skin, difficult or impossible to inject into well; partial fill will show skin on a build up but injection possible at a reduced rate; confirm with a sinker bar on wireline	reverse circulation or regular circulation
particle damage	skin on buildup test, difficult to inject; sometimes shows emulsions in oil wells; poor mud conditioning before cement; frequently encountered in open hole completions and horizontal wells	HCl or HCl/HF acid in matrix acid job solvent wash follow with acid in wells with oil base mud; foam or jetting cleanups are often useful
	may also be encountered following acid or frac stimulations or workover fluids where a dirty water was used or the water was hauled or stored in a dirty tank	filter treatment fluids - use clean tanks
	can reduce injection in flood projects - backflow shows particles and oil carry-over return	better cleaning of water
fracture plugging	large whole mud losses in naturally fractured formations; intermittent production at low and moderate rates; infrequent recovery of whole mud and mud fines. Some emulsions, especially after acid treatments; may also occur if hole is poorly cleaned during drilling	acid useful if damage is shallow; frac if deep; to prevent, improve solids recovery

paraffin in formation	seen as skin on test, may or may not disappear if well is shutin for several days; cloud point of oil is near the reservoir temperature; pressure drop may trigger paraffin drop out	treat with downhole heat generating processes if well is good producer; solvent soaks also used; some inhibitors available to be used with a hydraulic fracture treatment
paraffin after stimulation	injection of a cool stimulation fluid may precipitate paraffin in reservoir on contact; well may be clean up slowly (1 to 4 weeks) after stimulation even though load fluid is recovered more quickly; may see a decreasing skin if multiple buildup tests are run	allow the well to clean up on its own; use xylene preflush ahead of acid when the problem is known to occur
paraffin in flow lines	soft to hard deposits (not scale) in surface flow lines and equipment; paraffin will melt when exposed to enough heat (usually, about 150˚F is sufficient)	mechanical or solvent removal or pigging; inhibitors can be used
asphaltenes	soft to hard black mass that may occur as flakes, sludge, marble-size balls and as a stick buildup often occurs with paraffin; precipitation is triggered by destabilization of maltene resins caused by acid contact, outgassing, shear in pumps, electrically charged metal surface, temperature reduction and CO_2; asphaltenes soften with increasing temperature (t > 150˚F) but do not melt	treatment with aromatic (cyclic ring) solvents such as xylene or toluene; some surfactants are also useful for dispersion of asphaltic mass; use anti-sludge additive or xylene with acid in reservoirs with more than 0.5% asphalt to prevent sludges
tar	flows very slowly into perforations during production of oil; usually associated with the presence of a tar deposit near pay, frequently highly asphaltic; may contain some water that is tied up as droplets or "pockets" in the high viscosity mass	solvent soak as needed; test solvent with sample of tar before job; heat often helps
calcium carbonate scale	may form at any pressure drop, either in the formation or in the tubulars; may form very fast and can sharply limit production especially at gravel pack interfaces or near perforations in wells with high draw down across the perforations; may occur more frequently in earlier stages in some fields when pressure drop is more severe. Usually amorphous, non-crystalline form	HCI to remove and inhibitor to prevent; inhibitor may be squeezed into the formation for longer lived protection; some HCI jobs may trigger calcium carbonate scale in rare cases; inhibit acid or treat with EDTA if this is a problem
calcium sulfate scale	usually forms at pressure drop where induced by turbulence; more frequent where high sulfate waters contact high calcium waters and in CO_2 floods; scale is not acid soluble; may be found on outside of pumps and at intakes and gas expulsion ports and valves in downhole; crystals are characteristic for this scale	chemical converter or dissolver followed by acid; (do not contact converter or dissolver with acid); acid is not useful by itself; inhibitors placed by squeeze treatments are useful to prevent

barium sulfate scale	non reactive scale that forms at pressure drawdowns or where outgassing occurs; no readily apparent crystal pattern in many deposits; may occur as radioactive NORM scale in some areas where radioactive isotopes form in the lattice. NORM scales are detectable with gamma ray logging tools	scraping, water blasting or other mechanical removal; chemical treatment is usually not possible if scale occurs as nearly pure (> 90%) deposit or as thick (> 1/4", 6mm) deposits in pipes. Can be prevented by inhibitors
wettability problems	frequently occurs after an acid job where the corrosion inhibitor was not mixed in the acid just before injection; emulsions and reduced flow are common, particularly after inhibitor loss or oil base mud contact; may be temporary or permanent but most clean up slowly with time and flow; attempts to reverse natural wettability usually are short lived; natural wettability is determined by the natural surfactants in the produced fields	treat with mutual solvent wash over the pay, displace and soak
relative permeability problems	may occur when oil is injected into a gas zone or gas is injected into an oil zone that is above the bubble point	treat with high API gravity solvent such as condensate or xylene (low flash point); squeeze and produce back
retrograde condensate	a special case of relative permeability effect; a condensate (liquid phase) that forms from a rich gas; if the condensate forms in the tubing or casing, heading may occur; if condensate forms in the formation - creation of another phase will reduce permeability to gas; usually occurs near the wellbore where it manifests itself as an extra pressure drop	control drawdowns and repressure reservoir; redesign of tubing may be required
tubing problem	well refuses to flow although pressure is sufficient with the expected assistance from dissolved gas; well may head and die or liquid slugs may be produced if string is too large; rate is restricted by friction back pressure if tubing is too small	redesign string; a velocity string that will fit inside existing tubing may help if tubing is too large
salt	salt precipitates as a white mass in the tubulars or in the formation; usually associated with a cooling of super saturated water but may also be triggered by a pressure drop; may be seen early in the lives of some wells and become less of a problem as water cut increases; look for problems in formations with produced water salinity that is near saturation	fresh water or weak brine wash

bacterial infestation	a difficult problem to predict; it is more common in injection wells where surface or produced water is injected, if the colony is established in the water handling system, it can occur with injection of any waters; when tubing is pulled, brown to black slimy masses or an H_2S odor are indications; bacteria may cause slow reductions in the injectivity of a whole field; complete removal of the bacteria is rarely possible - treatment is usually on a remedial basis; untreated water in treatments; drilling fluid or injection water can sour reservoirs with SRB bacteria	treat with bleach followed by HCI (do not allow contact of bleach and HCI); more than one treatment may be necessary; alternative treatments are chlorine dioxide and bactericide slugs
poor perforations	shows up as damage on a build up test but cannot be cured with acid or mechanical changes in the well; problems such as screenouts of hydraulic fracture jobs, high injection pressures, sand production, downhole scale occurrence, unstable emulsions, and downhole paraffin and asphaltene deposits are common; problems with a well that cannot be broken down or even pumped into should always be approached by reperforating the well	reperforate
unstable formation	may occur in any formation that is poorly consolidated or that will fail under pressure; may occur with onset of water production or loss of pressure from depletion; problems include embedment of proppant, closing of acidized channels in acid fractures, spalling of formation into perfs or wellbore or production of solids	gravel packing, plastic consolidation, or rate limits
collapsed pipe	may show up as reduced rate or destruction of lift equipment. Check with a gauge ring on wireline or tubing. Has a variety of causes including severe corrosion, malfunctioning perforating guns, pipe flaws and wear of tubulars from drilling or lift system. Most common causes are earth shift loads caused by subsidence of producing formations with fluid and sand withdrawals, active faults, and formation movements near salt zones	If caused by earth shift forces, use heavier pipe or multiple strings. Liners, cement, and patches used for repair
tubing or casing leaks	sudden changes in GOR, WOR, pressure, or chemical analysis of water	repair; consider corrosion control program

8. RECOMMENDED READING

1. "Production Operations", Volume 2, 4th Edition, by Allen, T., and Roberts, A., OGCI, 1993
2. "Petroleum production Systems" by Economides M., Hill A. & Economides C.; Prentice Hall, 1994.
3. "Reservoir Stimulation", 2nd Edition, by Economides, M. and Nolte, K.; Prentice Hall, 1989.
4. "Reservoir Formation Damage" 3rd Edition by Civan, F.; Elsevier, 2015
5. "Well Completion Design" by Bellarby, J., Elsevier, 2009
6. "Petroleum Production Engineering", 2nd Edition, by Guo, B., Liu, X., and Tan, X. Gulf Professional Publishing, 2017
7. "An Introduction to the Basis of Well Completions Stimulations and Workovers",2nd Edition, by King, G.; Tulsa, 1998

CHAPTER 8: MATRIX ACIDIZING

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LEARNING OBJECTIVES

(All Examinable)

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

- Explain the importance of matrix stimulation in Production Engineering
- Identify and contrast the application areas of the various types of matrix stimulation techniques
- Explain the matrix stimulation well candidate selection principles
- Explain the impact of well stimulation on the production economics, rate, and well reserves
- Describe the matrix stimulation methods and campaigns
- Understand the basics of a matrix acidizing treatment (acid type, volume and injection rate)
- Explain the difference between the sandstone and carbonate acidizing
- Explain how the matrix stimulation reduces formation damage. Explain what types of damage can be reduced, and the damage sources.
- Identify and discuss the role of acid additives
- Explain the potential negative impacts of "matrix stimulation" and identify mitigation strategies
- Describe acid placement and diversion techniques

1. INTRODUCTION

Well stimulation aims at improving the well productivity index. There are many ways to do so, depending on what the major flow impairment mechanism is. If it is mainly related to formation damage and generally to the reservoir, then matrix (i.e. when treatment fluids are injected below fracture pressure to avoid fracturing) and fracture (i.e. when treatment fluids are injected above fracture pressure to promote fracturing) treatments are the most common types of (reservoir) stimulation. The first part of this chapter provides general discussion on well stimulation types, philosophy, and implementation. This is applicable to almost any stimulation treatment. The second part of this chapter focusses on acid matrix treatments. The fracture treatments (both proppant and acid fracturing) are discussed later in Chapter 9.

A stimulation treatment may be carried out immediately after the well is completed, and/or at any time in the well's producing lifetime when the treatment is economically justified. Periodical well stimulation is common.

Well stimulation is often a high reward well activity, but it must be reiterated here that, for both clastic formations and for some carbonate reservoirs:

- Prevention of formation damage is **nearly always** better than the cure (a remedial well stimulation).
- Stimulation techniques can themselves create formation damage if inappropriately designed.

2. WELL INFLOW AND STIMULATION TYPES

First, it is worth revisiting the well inflow model to explain what the different well stimulation methods are designed to achieve.

The well-known, semi steady state, radial-flow equation describes the well inflow as:

$$Q_o = \frac{k_o\, h\, (\overline{P_R} - P_{wf})}{141.2\, \mu_o B_o \{\ln(r_e/r_w) - 3/4 + S_{Total}\}} \qquad \text{(Eqn. 1)}$$

Where Q_o = well oil production rate (STB / day)
k_o = formation permeability to oil (mD)
h = reservoir thickness (ft)
$\overline{P_R}$ = volumetrically averaged reservoir pressure (psi)
P_{wf} = wellbore flowing bottom hole pressure (psi)
μ_o = oil viscosity (cp)
B_o = oil formation volume factor (reservoir bbl / STB)
r_e = well drainage radius (ft)
r_w = well radius (ft)
S_{Total} = skin (dimensionless)

An increased well inflow rate, or well stimulation, can be achieved by:

1. **Increasing** k_o, h or $\{\overline{P_R} - P_{wf}\}$
   OR
2. **Decreasing** S_{Total}, (r_e/r_w), B_o or μ_o.

Some examples of stimulation techniques are catalogued in Table 1, which identifies the parameter which the well treatment is targeting in order to increase the well's fluid inflow performance.

Technique	Objective
Mechanical Methods · Propped Hydraulic Fracturing · Underreaming · Additional Perforating · Re-Perforating	· Increase r'_w · Increase r_{wb} · Increase h_p · Replace blocked perforations
Chemical Methods · Matrix Acidizing · Other Chemical Matrix Treatments (Surfactants, Solvents, Mutual Solvents, etc.)	• Decrease S_D • Increase k & Decrease $\mu_{emulsion}$
Biological Methods · Microbial Stimulation	• Generate Acid to dissolve carbonates
Combined Mechanical / Chemical Methods for Carbonate Formations · Acid - Fracturing	• Increase r'_w
Thermal Methods · Steam Soak · Electrical Heating	• Decrease μ • Decrease μ

Table 1 Stimulation techniques.

(Note: r'_w in the table above is the so-called "effective radius", i.e. the virtual wellbore radius that would give the same productivity index value as the fractured well. see Chapter 3).

➢ *What other methods do you know that are used to improve well productivity?*

Of the methods listed above, a matrix (stimulation) treatment consists of injecting a fluid (e.g. acid or other chemicals) into the formation under 'matrix' (i.e. non-fracturing) conditions which ensures the injected fluids flow radially away from the wellbore and contact the damage zone.

An alternative stimulation technique –hydraulic fracturing –creates a high permeability 'pathway' (the fracture) that by far by-passes the near-wellbore formation. This high permeability fracture increases the effective well exposure to the reservoir.

Chapter 7 described some of the many sources of formation damage which reduce the formation's near-wellbore permeability; and the ways to assess and mitigate it. Figure 1 summarises some of them, as well as illustrates in what situations the other stimulation methods: fracturing and thermal – are useful.

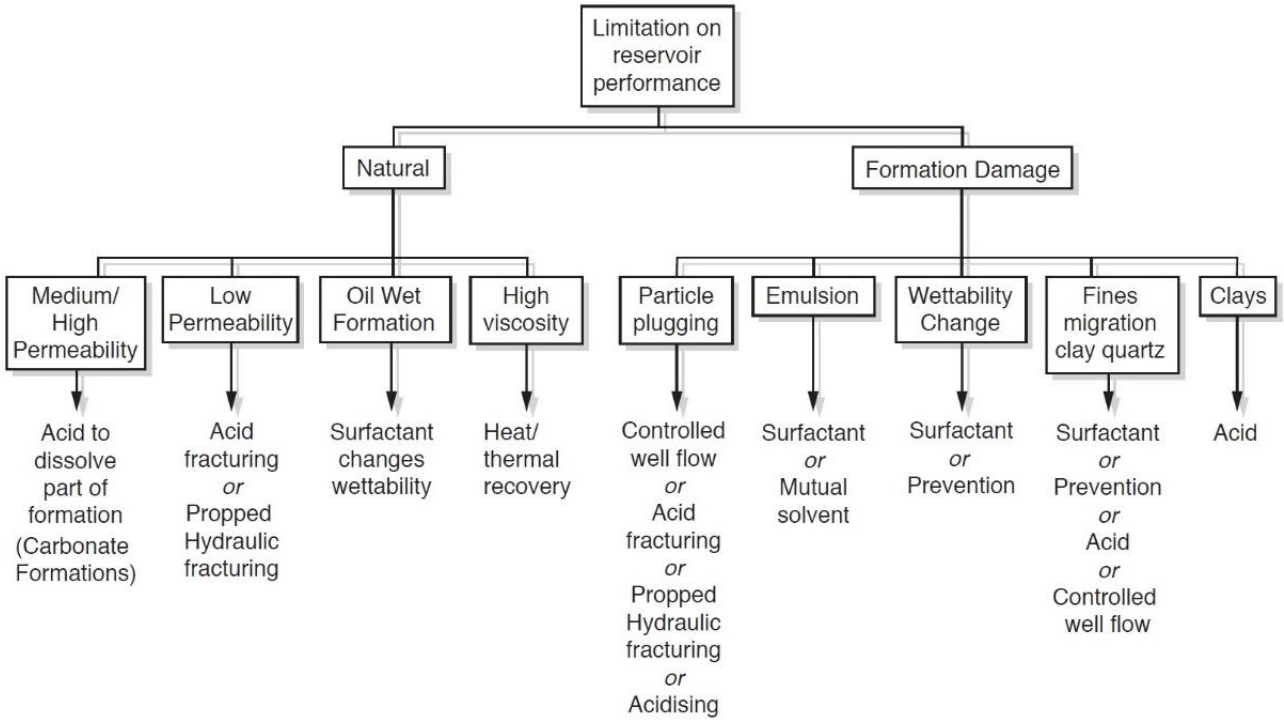

Figure 1 Matrix and fracture stimulation treatments that can remove limitations to the well's inflow performance.

- *Feel free to relate the above methods to the formation problems described in Chapter 7.*

Note in Figure 1 that the natural reservoir problems can also be dealt with. Basically, it normally makes sense to target formation damage where it is the major well productivity problem, while the reservoir can deliver otherwise. In low permeability reservoirs however, the formation damage's relative impact may be small compared to the poor reservoir performance, and rather a fracture is needed to improve the well-reservoir interface. Table 2 provides global guidelines for choosing the most appropriate stimulation technique for a particular well.

Clastic Reservoirs

Treatment Type	Skin	Permeability
Propped Hydraulic Fracture	Low	Low
Propped Hydraulic Fracture	High	Low
Frac and Pack	High	Medium
Matrix	High	Medium / High
Treatment Probably Not Required	Low	Medium / High

Carbonate Reservoirs

Treatment Type	
Propped Hydraulic Fracture	As For Clastic Reservoirs
Acid Matrix Treatments	Widen Natural Fractures Acid Etch (Short) Channels (Wormholes)
Acid Fracture	Hetergeneous Formations
Closed Fracture Acidising	-
Acid Viscous Fingering	Homogenous Formations

Table 2 Global guidelines to select a stimulation treatment for clastic and carbonate reservoirs. *(Fracturing techniques are explained in Chapter 9).*

It is obvious now that the source(s) of damage must be well understood when selecting and designing a well stimulation treatment. Typical sources were discussed in Chapter 7 and some are illustrated in Figure 2 which also depicts the location of formation damage:

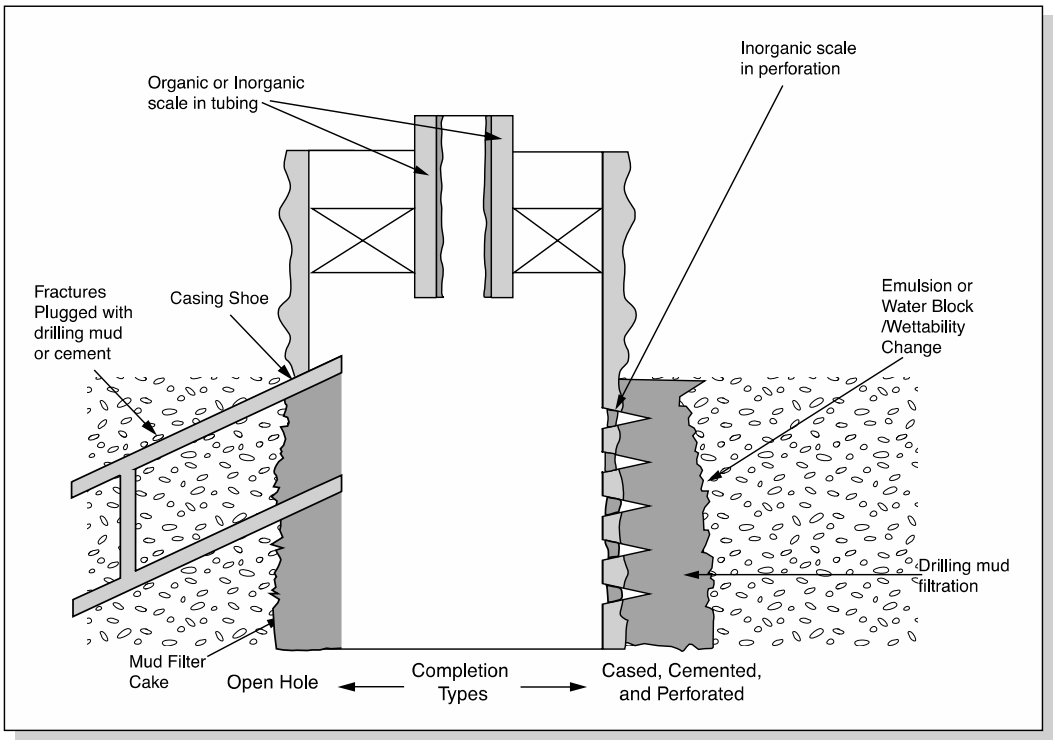

Figure 2 Formation and other damage types and location for cased and openhole completions.

➢ *Feel free to relate the above damage locations to the well operations described in Chapter 7.*

Once the treatment type is identified, a treatment strategy is normally designed and is ready for its execution to be authorised, carried out and, eventually, evaluated on a field basis. Well candidates in a field are treated one by one, ideally with the lessons learned on the way and immediately applied to every next well. Figure 3, the matrix stimulation cycle example, summarises the complete process.

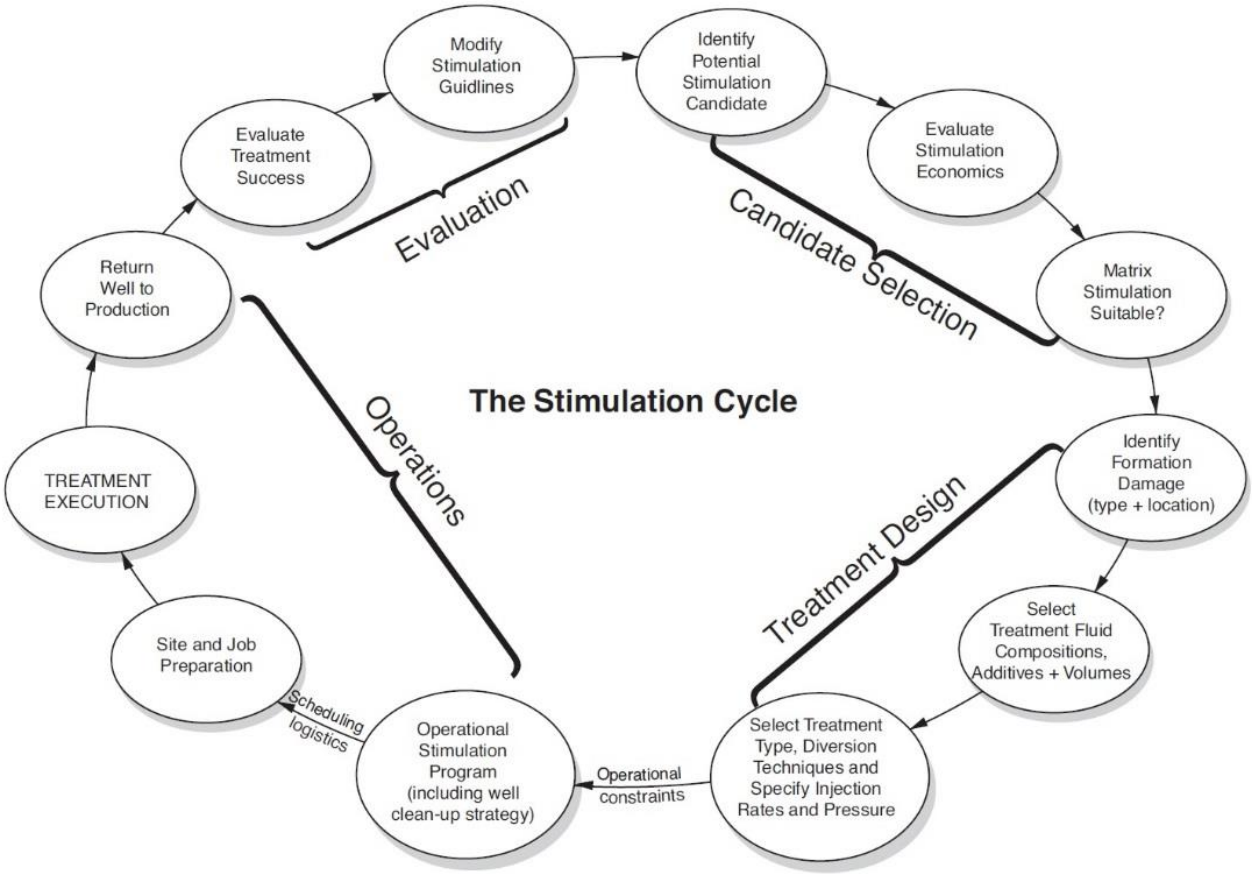

Figure 3 The Stimulation Cycle.

The following sections will briefly describe some selected elements of this cycle clockwise, starting from the candidate selection.

3. CANDIDATE SELECTION

The selection of stimulation candidates that have suffered sufficient formation damage is the key to a successful stimulation campaign. This involves two stages:

1. *Identifying and quantifying* the parameters which control each well's productivity.

2. *Confirming* that a stimulation treatment can improve the well production.

It is important here to distinguish between the well's Inflow Performance and the well's rate of production. This is because an improvement in the well's Inflow Performance from the reservoir has only a limited effect on the daily well production if the well's Vertical Lift Performance is limited by tubing/artificial lift/facilities restrictions. The complete production system from the reservoir boundary to the production storage facilities must be considered when predicting the possible increase in the well's production rate (Figure 4).

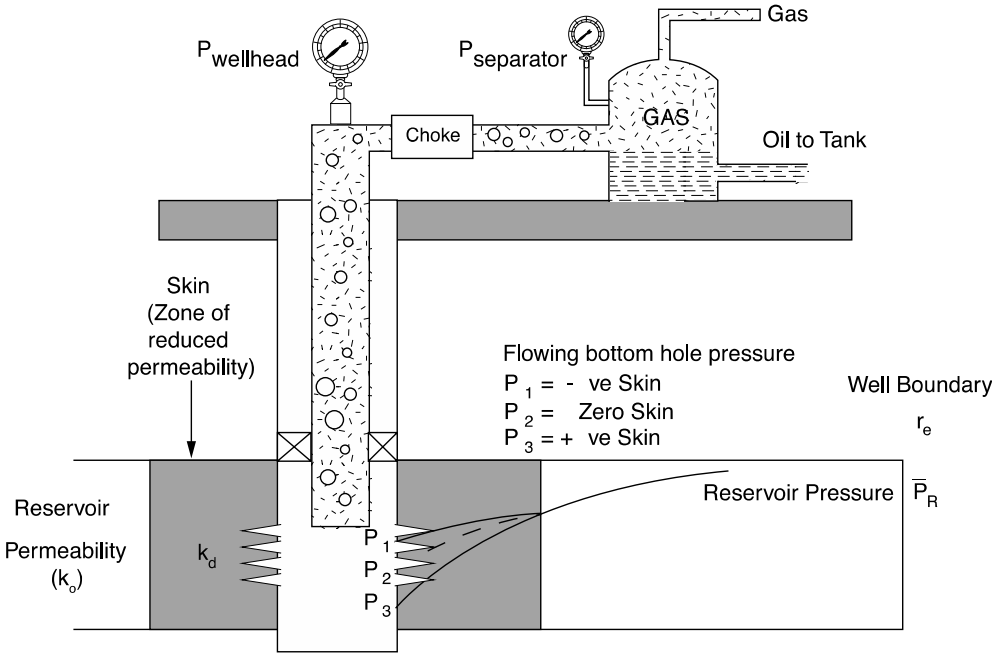

Figure 4 The Well Production System.

The Screening Criteria evaluate whether the well has a sufficient minimum of:

1. *Remaining reserves* to justify carrying out the well stimulation. This depends on the oil saturation, porosity and drainage area.
2. *Well inflow productivity* (i.e. the potential to increase production after reducing damage skin. This is often related to permeability and reservoir pressure.)
3. *Facilities Capacity* to lift and process the extra fluid production *(this is often limited by the production system capacity as well as by the lifted fluid's watercut).*

Table 3 summarises typical minimum values of the requirements for a successful (matrix) stimulation treatment based on experience from a number of fields. These can be used as preliminary screening criteria for stimulation candidate selection if specific field data is not available.

Parameter	Oil Reservoir	Gas Reservoir
Hydrocarbon Saturation	> 40%	> 50%
Water Cut	< 30%	< 200 bbls/MMscf**
Permeability †	> 20 mD *	> 1 mD
Reservoir Pressure	< 70% depleted	twice abandonment pressure
Production System	~ 20% spare capacity ø	

* Higher value required for viscous oil production
ø Lower value if several wells are manifolded together
† Wells with lower permeabilities are potential hydraulic fracturing candidates; actual values depend on local perforation cut-off criteria
** Evaluate potential for well killing itself due to liquid loading in the tubing

Table 3 Typical minimum Well Selection Criteria for a Matrix Acidizing Treatment.

- *Feel free to discuss and explain these criteria.*

Alternatively, installation of an artificial lift method which allows an increased drawdown; or re-perforation to extend the producing interval may be a more effective method of increasing production.

Ideally, each candidate well should be evaluated on its own merits rather than, for example, deciding to acidize every well in the field as part of the standard, well completion programme.

3.1 Treatment Timing

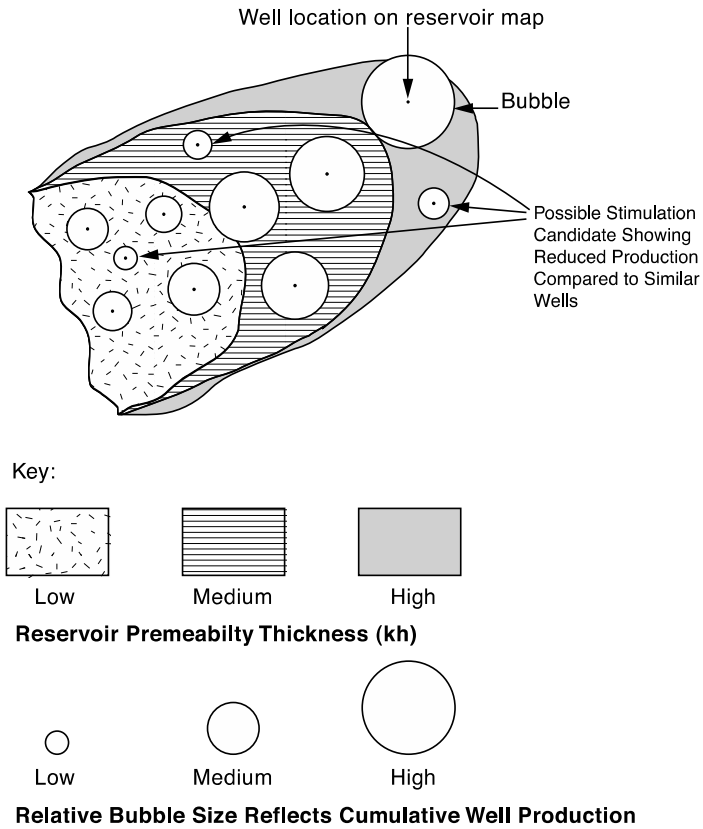

Figure 5 Visualising field production data using a "Bubble Map" output from a modern, production surveillance database

Well stimulations may be carried out immediately after the initial drilling/completion programme has been finalised e.g. to correct formation damage caused by the drilling mud. The well is essentially assumed to meet the Table 3 criteria. Alternatively, the stimulation candidate may be identified as a result of routine, field production surveillance. Figure 5 schematically illustrates the typical output from a production surveillance data base. This graphical display recognises three potential well stimulation candidates which are identified as producing less than the surrounding wells with comparable reservoir quality ($k_o.h$).

Once a particular well has been identified for further study, its attributes must be checked against the criteria in Table 3. The three wells identified have produced significantly less than comparable wells. They may indeed be the potential stimulation candidates, or they may e.g. have:

- Been drilled later than the other wells, so the reserves in their drainage area have already been partially depleted.
- A smaller drainage area than the other wells, being situated near a reservoir boundary or surrounded by other wells, etc.
- Artificial lift has not been installed or is working inefficiently.

The campaign can be commissioned once it has been confirmed that the well candidates can indeed benefit from the stimulation treatment, i.e.

- their flow is not restricted by other effects such as mechanical skin, high WC, non-Darcy flow, poor completion, etc.;
- there is nothing preventing their stimulation and post-stimulation production, such as production limit due to system capacity, or water coning control, or sand production; or logistical/completion difficulty to access these wells and install stimulation equipment in them; or the need to maintain continuous production and cash flow;
- identification of the cause and location of the formation damage has been done, and this damage qualifies for stimulation.

As mentioned, well inflow productivity must be checked as a stimulation criterion. This is illustrated in the following section.

3.2 Estimation of Production Gain

Matrix treatments, acidizing in particular, aim to remove the excess flowing pressure drop (ΔP_d) created by the presence of a volume rock which has suffered formation damage (i.e. has a lower than original permeability, Figure 6).

Restoration of the "ideal" well productivity by removal of formation damage skin (i.e. by making $S_d = 0$) as a result of increasing the formation damage zone's permeability (k_d) to the original permeability value (k_o); can be described by the Hawkins formula in vertical wells (Eqn. 2):

$$S_d = \left\{\frac{k_o}{k_d} - 1\right\} \ln \frac{r_d}{r_w} \qquad \text{(Eqn. 2)}$$

where S_d = skin due to formation damage

k_o = formation (original or undamaged) permeability to oil (mD)
k_d = (near wellbore) damaged formation permeability to oil (mD)
r_d = radius of formation damage (m)
r_w = wellbore radius (m)

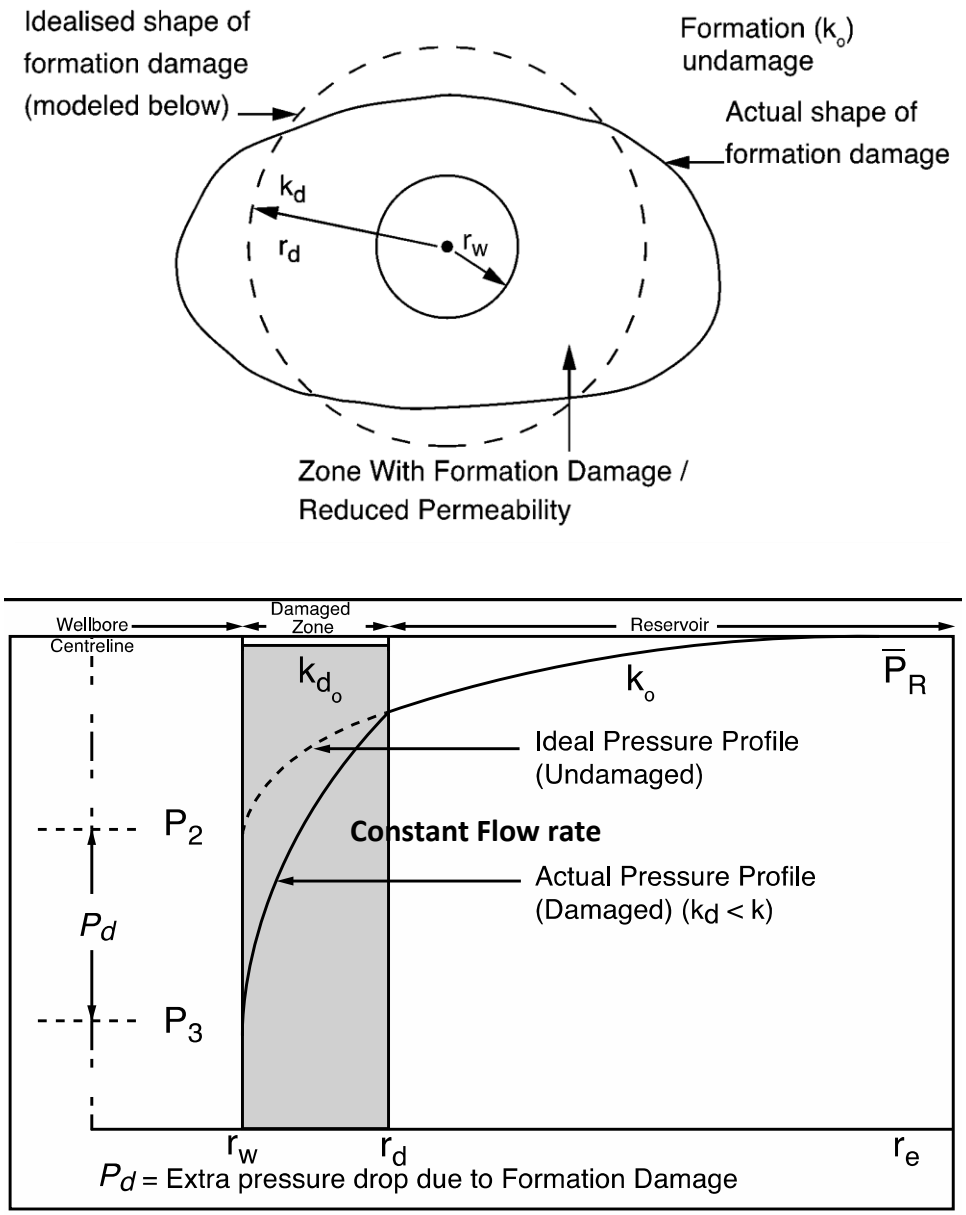

Figure 6 The effect of a near-wellbore damaged zone on the well inflow pressure profile.

The Hawkins formula analyses the impact of varying levels and depths of formation damage on the well productivity. The reduction in the skin value can be translated into an increase in the well's Flow Efficiency, and further used in candidate selection.

It is possible to make an interesting observation. Figure 7 illustrates the Hawkins formula. Note how the impairment of 80% (i.e. k_d/k_o = 0.2 or 20%) with a depth of Formation Damage (r_d) of 0.75 ft or 1.5 ft reduces the Flow Efficiency quite significatnly: to 70 and 60% respectively. Increasing the damage radius to a depth of 3 ft gives a small further decrease in the Flow Efficiency.

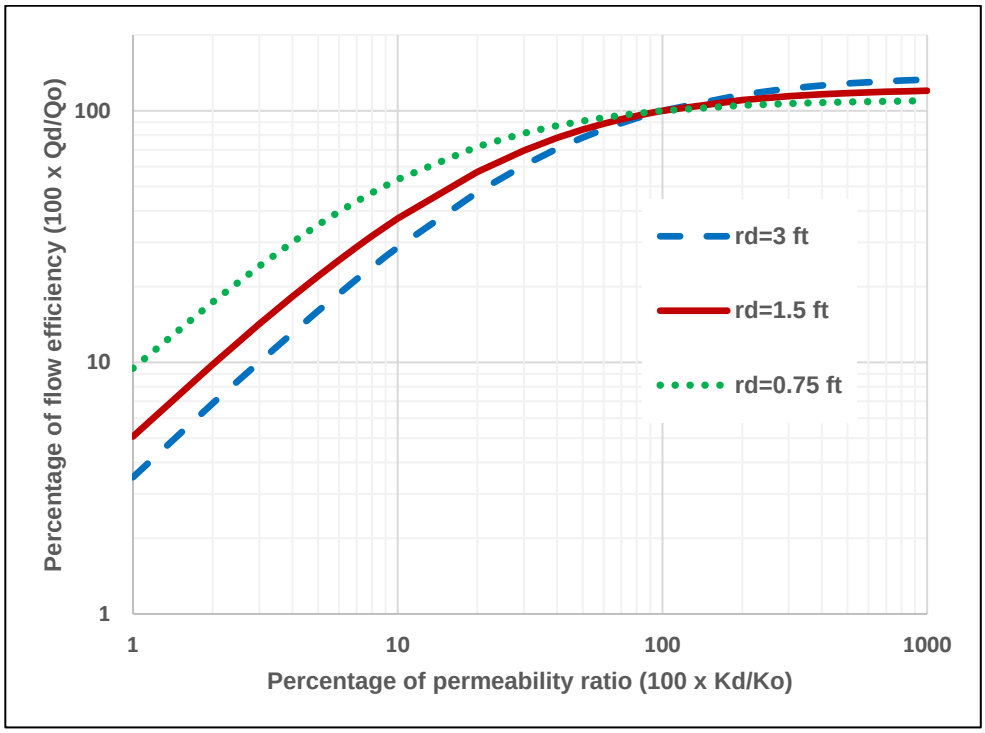

Figure 7 The Hawkins formula predicts the Flow Efficiency from near wellbore formation damage or stimulation.

This is because the pressure drop is the highest close to the wellbore (as explained in Chapters 3 and 7), and therefore this zone is most sensitive to the damage. Figure 6 illustrated how the pressure gradient continually increases as the fluid approaches the wellbore.

Hence the productivity reduction caused by a zone of lower permeability and constant thickness, will depend on its location (or distance from the wellbore). Figure 8 illustrates how this results in a significantly smaller decrease in Flow Efficiency when a zone with 80% formation damage ($k_d/k_o = 0.2$) is moved away from the wellbore. This effect will be important when we discuss acidizing of sandstone reservoirs.

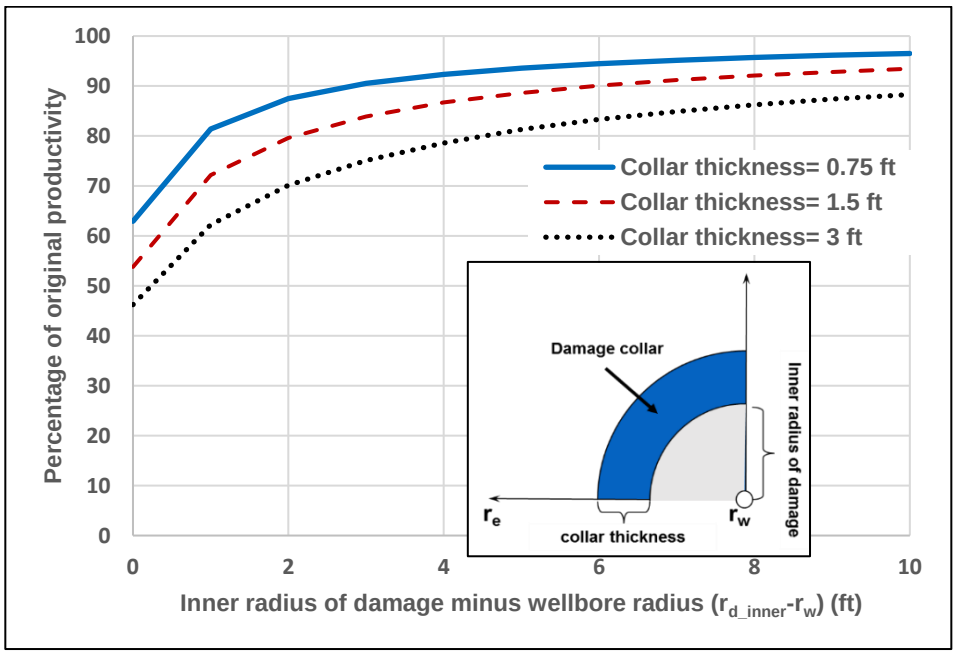

Figure 8 The Well's Flow Efficiency depends on the location of the zone of formation damage.

All in all, estimating the expected, net hydrocarbon production gain from the stimulation treatment is the important step. Estimation methods include:

1. Measuring the value of the well's total skin by a well build-up test. The Formation Damage skin is derived by subtracting estimates of all other parameters that contribute to the total skin value, such as e.g. well deviation or limited perforation interval.

2. The Hawkins formula (equation 2) can be used to estimate the reduction in Flow Efficiency if the extent (k_d/k_o) and the depth of the formation damage (r_d) are known, or can be estimated, with reasonable confidence. For example:
   a. (k_d/k_o) could be derived from laboratory Formation Damage tests in which the permeabilty profile as a function of depth was measured by pumping the drilling mud with a planned overbalance across the face of a (reservoir or similar permeability) core.
   b. When the well is drilled, the resisitivity array log is routinely run across all target zones to determine the hydrocarbon saturation. The depth of the formation damage can be determined by measuring the maximum invasion depth of the filtrate from a water based mud. The depth of formation damage is then assumed to be no greater than the maximum invasion depth of the drilling mud's fitrate.

3. Previous experience from stimulation of similar wells in the same field is often a good guide to the expected gain from the planned well stimulation treatment.

It is nevertheless almost aways difficult to estimate the exact extent of the damage and the chances of its removal. It's a good practice to introduce risks and success probability into this type of calculations.

4. AN INTRODUCTION TO WELL STIMULATION ECONOMICS

Once the potential production increase from a stimulated well has been estimated, it is important to assess its economic value.

Well interventions are only justified when the net monetary benefit of the resulting extra oil and/or gas production repays the cost of the intervention while also meeting the economic criteria specified by the operator's management. Estimating the potential benefits from a stimulation treatment is often based on the fact that production wells typically show a constant, long term, annual percentage decline in net hydrocarbon production. A similar decline rate is often observed for most wells producing from the same reservoir. The production decline rate can often be expressed as a straight line plot of the logarithm of net hydrocarbon production against time (Figure 9).

The straight line with a steeper, post stimulation slope (or greater, annual, net hydrocarbon production decline rate) in Figure 9 corresponds to faster depletion of the well's remaining reserves. Note that extra oil reserves have been created by the treatment; both by an immediate increase in the production rate and by the well producing above its economic limit for a longer period of time (stippled area in Figure 9 which refers to a medium economic limit).

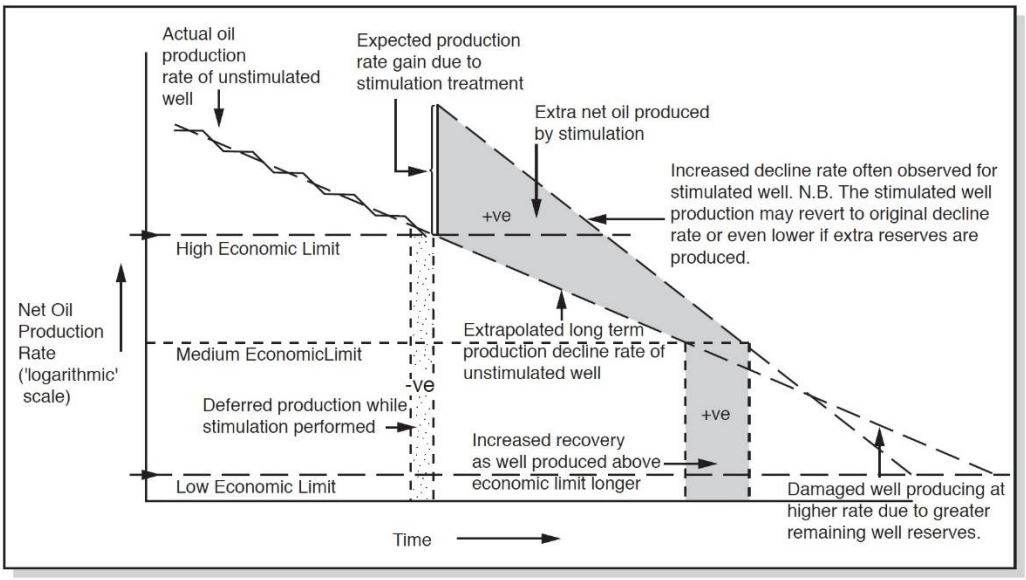

Figure 9 The extra oil production from a stimulated well depends on the well's economic limit.

N.B. The well's economic limit is the hydrocarbon production rate at which the net income after subtracting all taxes, royalties, etc., from the sale price is equal to the operating cost. The well's economic limit is thus the value at which the cash flow generated by the well becomes negative.

The stimulated well's decline rate can also return to the original value or it may even decrease after the stimulation treatment rather than having a faster decline rate as illustrated in Figure 9. This can occur when the stimulation treatment reopens blocked perforations and/or increases effective height of the production zone.

The interplay between the well's decline rate before and after the treatment with the well's economic limit determines whether stimulation is classified as "Production Acceleration" or "Increased Reserves". This is shown in Figure 10 that illustrates a well's increase in production rate after a successful stimulation treatment in which the gain in production is followed by an increased production decline rate.

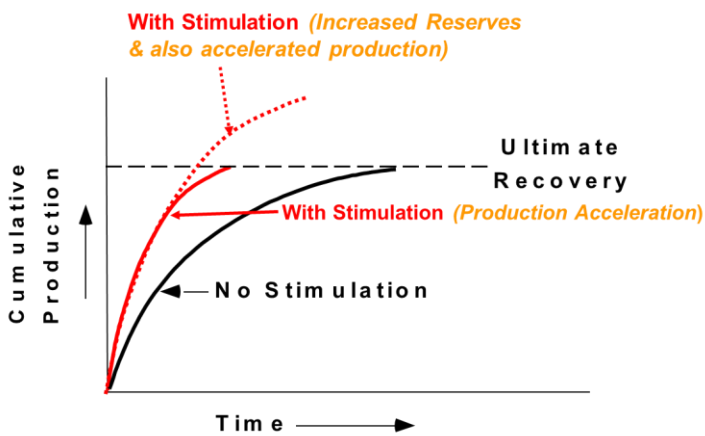

Figure 10 Stimulation gives production acceleration with/without increased reserves

Matrix stimulation normally uses "payback time" as the criterion to judge if the treatment is economically justified. "Payback time" is the production time in days for the increase in net value of the daily hydrocarbon production to pay for the costs of the well stimulation treatment (including the loss of production due to the well not producing while the well stimulation treatment is being carried out). A "payback" time of less than 6 months for a matrix acidizing treatment is common, which makes it an attractive routine treatment.

The well stimulation candidate with the shortest predicted payback time, or highest rate of return, that is operationally feasible should be carried out first. However, stimulation candidates can also be selected for other, field and reservoir management reasons.

- *Feel free to attempt Tutorial 1.*

5. SELECTION OF (CHEMICAL) TREATMENT TYPE

As explained, a matrix stimulation treatment that is both technically and economically successful requires the following steps:

1. *Identifying* a candidate well which is capable of producing increased volumes of hydrocarbons once the well's formation damage skin is removed.

2. *Confirming* the (net) income from the additional hydrocarbons produced after removal of the formation damage repays the cost of the treatment and meets the operator's economic criteria.

3. *Selecting* the optimum treatment fluid to remove the formation damage.

4. *Preparing* a detailed design for the operational aspects of the treatment to achieve the required economic criteria.

The chosen chemical treatment fluid should be targeted at the particular type and location of the formation damage to be removed.

Most of the recommended treatment targets and fluids listed in Table 4, Table 5, and Table 6 have already been mentioned earlier in this course.

Treatment Type	Objective	Location	Comments
Acid (inorganic) and solvent (organic) washes	Remove flow restrictions eg. inorganic / wax scale,	Tubing only	Circulated down tubing, then back to surface Not injected into formation
Acid (inorganic) and solvent (organic) washes	Remove flow restrictions caused by kill pills, etc	Tubing, open hole, perforations and completion	Circulated down tubing, and across completion. For open hole often allowed to remain stationary ("soak") across the completion. Not injected into formation
Matrix acidising	Dissolve rock components (drill solids, precipitates, clays etc) and formation damage to improve well / formation connectivity	Near wellbore (< 1m depth from sand face)	Injected into the formation
Other matrix treatments	Solvents and surfactants remove emulsions, wax etc. from oily wells and inhibitor residues from gas wells. Chemical inhibitor squeezes prevent scaling etc. during well production	Near wellbore (< 1m) At depth (< 10m) from wellbore	Injected into the formation Large volume treatment Inhibitor returns with produced fluid

Table 4 Types of (chemical) matrix treatments.

Type Damage	Symptom	Cause	Solution
Oil wet formation	Reduced oil production	Corrosion inhibitors. Oil based mud.	Mutual solvent* / water wetting surface
Water block	Reduced gas production in low permeability or depleted formations	Increased, near wellbore, water saturation. Fluid loss during drilling / work over	Surfactant / alcohol solution injected with nitrogen
Emulsion	Viscous emulsion near wellbore	Emulsion stabilised by surfactant or oil wet solids e.g. asphaltenes	Inject mutual solvent / demulsifier
Wax	Deposit on tubing or in formation	Oil cooled below cloud point	Dissolve in heated oil / solvent or disperse in surfactant solution. Mechanical removed (scraping). Crystal growth inhibitors
Asphaltene	Deposit in facilities, tubing or in formation	Pressure reduction (precipitation often starts near bubble point)	Mechanical removal; dissolution and inhibition
Bacterial Slime or Deposit	Deposits (mainly in well) and corrosion	Bacterial Infestation	Bactericide prevents infestation. Mechanical removed and/or oxidising agents (e.g. bleach or chlorine dioxide removes deposits)
Silts and Clays	Reduced well inflow	Clay swelling and fines migration	Clastics: dissolve damage with HCl/HF Carbonates: HCl to dissolve formation / bypass damage
Inorganic Scale	Deposit on well equipment or in formation	Formation brines becoming super saturated due to T and P reduction or mixing of incompatible brines	Mechanical removal in tubing Inhibition (inject inhibitor in tubing or squeeze into formation) Dissolution

* Mutual solvents dissolve both oil and water phases

Table 5 Matrix stimulation fluid selection.

Type of Scale	Usual Manifestation	Treating Fluid	Comments
Carbonates	$CaCO_3$	HCl	very common treatment
Sulphates	$CaSO_4$ / $CaSO_4.2H_2O$	"Conversion Treatment" (Na_2CO_3 solution followed by HCl) or EDTA	common treatment
	$BaSO_4$ / $SrSO_4$	EDTA + Synergist	very expensive
Chlorides	NaCl	H_2O	gas well only
Sulphur	S	liquid at most downhole temperatures	gas well only
Iron	FeS / Fe_2O_3	HCl + chelating agent, also sometimes reducing agent	encountered in an acidic environment (CO_2 / H_2S)
Silica / Aluminosilicate	SiO_2 / $NaAlSiO_4$	HCl / HF	these scales cause Formation Damage as well as deposit in tubing

N.B. Scales are inorganic deposits formed by supersaturation of formation brines or mixing of two incompatible brines. Mechanical removal is always an option in the tubing.

Table 6 Fluid selection for removal of inorganic scale.

Table 4 refers to acid (tubing) washes. They share a similar composition to matrix acidizing fluid, using the same acids and additives. They are used to improve the well outflow by removing deposits which have formed on the tubing wall.
The treatment fluid is retained within the tubing during a tubing wash i.e. it is NOT injected into the formation. This procedure avoids formation impairment by solid particles dispersed in the treatment fluid (e.g. rust) that had been dislodged from the deposits on the tubing wall but not dissolved in the acid.

6. TREATMENT SUCCESS EVALUATION

Once the treatment has been carried out (or sometimes during it being carried out) the production interval's performance ideally should be logged/monitored and compared with the pre-treatment performance to identify the successfully stimulated zones and optimise the treatment design for subsequent stimulations. The traditional way is to use flow-meter assisted production logging as was explained in Chapter 2. The well's old and new skin factors measured in build-up tests can also be used: they can be compared to assess the stimulation success. Let alone the well pre- and post-treatment flowrate (or flow efficiency) shows the overall success value. Many other measurements can assist the optimal design, evaluation, and 'on-the-fly' monitoring and optimisation of the treatment. For instance, DTS (distributed temperature sensor) on the stimulation coiled tubing (if any) can be used to monitor the treatment's impact on the well's flow performance in real time during the treatment, and to make appropriate adjustments on site.

As mentioned, very valuable "lessons" are learned by evaluating whether the treatment achieved its objectives by comparing the well's inflow performance before and after a stimulation treatment. Stimulating a number of wells in an oil or gas field in the form of an organised campaign is cheaper than carrying out single well treatments on an ad hoc basis. Thus, the design methodology can be adjusted with experience gained by evaluating the efficiency of early treatments being used to improve later treatments.

Figure 11, the results of a stimulation campaign in a large gas field, compares the pre- and post-matrix stimulation well productivity for a large number of wells. The decrease in average, well formation damage skin, or increase in Flow Efficiency, achieved by the matrix stimulation treatment is clear.

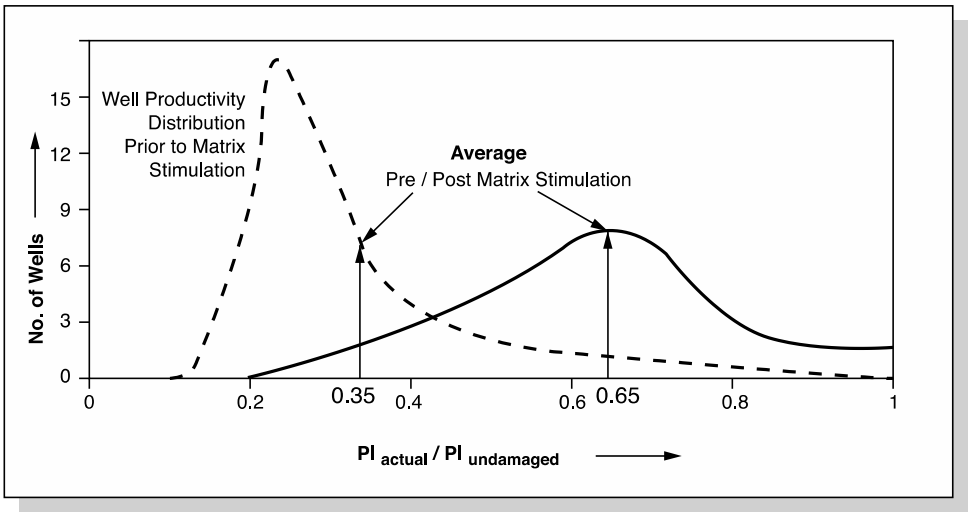

Figure 11 Evaluation of a Stimulation Campaign In a large Gas Field.

The Figure 3 Stimulation Design Methodology was followed during the campaign. Continuous evaluation of each treatment's performance allowed the treatment cost to be reduced by halving the "acid volume per unit net perforated interval length" while maintaining the same, favourable, well response to stimulation. Evaluation showed:

1. That matrix stimulation is a high reward activity. The increased field production capacity was delivered by stimulation at 10% of the cost of generating the same capacity through infill drilling.

2. This favourable economic result was achieved despite a 15% technical failure rate defined as *"No increase in the Flow Efficiency"* i.e. the well Productivity Index was the same or less after the stimulation treatment.

The rest of the chapter will now focus on matrix acidizing treatments types, their mechanisms, designs, and considerations.

7. ACID TREATMENTS

Acidizing treatments include: matrix acidizing (a.k.a. 'matrix acidization' or 'acid job'), fracture acidizing (a.k.a. 'acid fracturing'), and acid washes (aimed at removing deposits like scales from the well completion as explained earlier. They are also common in cleaning the tubing with e.g. 15% HCl acid, possibly using a coiled tubing, before the matrix acidizing treatment in order to prevent injection of rust and scale into the formation).

Matrix acidizing can be applied to reduce or remove formation damage in both carbonate and sandstone (clastic) reservoirs, though different acids are used and mechanisms take place. Essentially, matrix acidizing in sandstone reservoirs aims at dissolving the pore plugging material (clays, fines) and ideally reducing the damage skin to zero; while in carbonate reservoirs it aims at dissolving the rock and creating narrow, branching holes (a.k.a 'wormholes') in the matrix that bypass the damage zone, often reducing the damage skin to around -2.
Acid fracturing, on the other hand, can be done only in carbonate reservoirs as somewhat alternative to proppant fracturing, as will be explained in Chapter 9.

(Note that the term 'acid' may be confusing: pure acid is not used. Instead, its solute in water is. E.G. '15% wt. HCl acid' means a solution of 85% (by weight) concentration of water and 15% hydrochloric acid).

The widely available and relatively inexpensive, mostly used acids are mineral (inorganic): HCl hydrochloric acid that easily dissolves carbonates, and HF hydrofluoric acid that dissolves both carbonates and silicates (clays and feldspars). HCl is used in carbonate reservoirs, whereas a mixture of HCl and HF acids (called 'mud acid', with typical concentration of 12% wt. HCl and 3% wt. HF) is used in sandstone reservoirs.
The mineral acids are very strong and can cause fast corrosion of the well completion and too fast a reaction with the matrix, especially at high (> 250° F) temperatures. In this case they can be substituted with milder, organic acids, the most common of which are formic and acetic acids.
Retarded acids, most often gelled (with polymers and surfactants) or emulsified (with oil and emulsifier) HCl, are sometimes required to limit the reaction (a.k.a. 'spending) rate and promote diversion as will be explained later.

During a matrix treatment a series of several volumes (flushes) of different fluids are injected. There are normally a pre-flush (fluid injected to prepare the formation for the main flush), main flush (the acid), and overflush (a.k.a. 'afterflush' or 'post flush') injected to displace the acid from the wellbore deeper into the formation to avoid completion corrosion and secondary formation damage as will be explained later. Once the acid has reacted (i.e. is 'spent') the well is put back on production to recover the spent acid during the 'flowback' period.

In carbonate matrix acidizing the preflush may not be needed. In sandstone acidizing it is normally a 15% wt. HCl to mainly dissolve calcium carbonate (calcite) $CaCO_3$ scale and/or matrix (remember the rocks consist of various minerals, and there is often a small proportion of carbonate minerals in sandstone reservoirs) before the mud acid enters the treatment zone. This is because if HF contacts $CaCO_3$, it will form a calcium fluoride precipitate (CaF_2) which is almost insoluble and can block the pores and cause damage.
Preflush may also be needed to displace the fluids potentially incompatible with the main acid deeper into the reservoir from the treatment zone. E.G. the crudes with high risk of depositing asphaltenes or forming emulsion or sludge in the presence of acid should be displaced.

The main flush is normally HCl (7.5%-28% wt.) in carbonates, or the mud acid in sandstones. The treatment zone is normally within 1-2 feet from the wellbore, sometimes deeper.
As the soak time passes, the spent mud acid's pH gradually increases (from around 1 to about 2-7) and the elements kept in solution can redeposit and clog the pores again. Partly this redeposition time is delayed due to the presence of HCl in the mud acid that keeps pH low for longer. However, it is best to displace the spent acid deeper into the formation (normally beyond 4 ft) so that when the deposits precipitate there, it will have small impact on the well productivity as was explained in the 'damage collar' example earlier (Figure 8).

Overflush is used to displace the spent acid from the wellbore and deeper into the reservoir, as well as improve the flow performance of the near-wellbore zone. Typical examples of the overflush composition include: 5%-10% wt. HCl solution; or 2% wt. NH_4Cl optionally with mutual solvent to improve wettability; or diesel oil or kerosene in oil wells; or natural gas or nitrogen in gas wells.

8. TYPICAL ACID FORMULATIONS USED FOR MATRIX ACIDIZING

The behaviour and chemistry of the most frequently used acids in well stimulation treatments are discussed in the following sections.

8.1 Hydrochloric Acid (HCl)

Hydrochloric acid is widely available commercially at concentrations of up to 32% wt. Its main reaction is to dissolve carbonate minerals (or scale) present in the formation and the well itself e.g. calcite (chalk or limestone), dolomite, siderite etc. The amount of the mineral dissolved is a function of the volume and concentration of acid used. For instance, the mole amounts (stoichiometry) for the reaction with calcite is:

$$2HCl + CaCO_3 \rightarrow CaCl_2 + CO_2 + H_2O$$

The dissolving power can be further calculated, indicating how much acid solution by mass (gravimetric dissolving power β) or by volume (volumetric dissolving power *X*) is needed to dissolve a mineral.
The gravimetric dissolving power is defined as:

$$\beta = C_a \frac{v_m MW_m}{v_a MW_a}$$

Where C_a is the weight fraction of acid in solution
v_m – stoichiometry number of mineral
v_a – stoichiometry number of acid
MW_m – molecular weight of mineral
MW_m – molecular weight of acid

Further, the volumetric dissolving power can be found using the densities as: $X = \beta \frac{\rho_a}{\rho_m}$

- *Feel free to attempt Tutorials 2 and 3*

The calculations for multiple mineral and/or acid systems are much more complex, usually solved numerically.

All the chloride salts formed by the reaction of hydrochloric acid with the formation and the formation damage have a high solubility in water. Hydrochloric acid is also capable of (partly) dissolving chlorite (an iron-containing clay). The major secondary precipitation reaction of hydrochloric acid occurs when it reacts with iron containing minerals. Highly impairing, gelatinous precipitate of iron hydroxide is formed when the acid becomes spent (i.e. the hydrochloric acid has all been consumed by reaction with the formation and the pH (acidity level) is approaching the neutral pH value of 7).

Most of the iron-containing minerals present in the formation are in the reduced (Ferrous or Fe^{++}) form, leading to the precipitation of Ferrous hydroxide {$Fe(OH)_2$}. The acid will also dissolve any rust present on the walls of the surface tanks and flow lines as well as on the surface of the wells tubing, casing, etc. The rust forms Ferric hydroxide {$Fe(OH)_3$}, which is also a highly impairing, gelatinous precipitate which forms from quite acidic solutions of pH values ≤ 1.

Hydrochloric acid is highly corrosive to the steels used in well completions. It must be inhibited with additives that reduce corrosion and precipitation of iron hydroxide; the acid's contact with rust should be minimised as well.

8.2 Mud Acid {Hydrochloric (HCl) and Hydrofluoric (HF) Acid mixture}

The majority of acid stimulations of clastic reservoirs are carried out with "Mud Acid", a mixture of Hydrochloric (HCl) and Hydrofluoric (HF) acids. This very aggressive acid is capable of dissolving minerals such as quartz, clays, micas etc. (hence the name "Mud Acid"). These minerals are inert to hydrochloric acid alone.

Mud Acid is normally not transported to the wellsite due to its highly aggressive nature. It is prepared at the well site by adding the appropriate amount of solid ammonium bifluoride to the hydrochloric acid solution. Typical formulations used in the field are "Full Strength Mud Acid" (12% wt. HCl and 3% wt. HF) and "Half Strength Mud Acid" (6% wt. HCl and 1.5% wt. HF).

Acid formulations with an even lower fluoride concentration and higher chloride:fluoride ratio {e.g. 0.5% wt. HF and 6% wt. HCl} are often used when acidizing formations with a high clay content. *If acidized with strong acids, the first few inches of the high-clay content rock will be aggressively attacked by the acid destabilising the rock while hardly treating damage any deeper.*

Virtually all the chloride salts formed by the reaction of the formation, as well as the formation damage, with hydrochloric acid have a high solubility in water. However, as mentioned, fluoride salts (F^-) and the fluorosilicates (SiF_6^{--}) of sodium (Na), potassium (K), calcium (Ca) etc. are very insoluble and precipitate when formed; as indicated by a downward pointing arrow:

$$CaCO_3 + 2HF \rightarrow CaF_2 \downarrow + CO_2 + H_2O$$
$$SiO_2 + 6HF \rightarrow H_2SiF_6 + 2H_2O$$
$$H_2SiF_6 + 2K^+ \rightarrow K_2SiF_6 \downarrow + 2H^+$$

The insolubility of these salts implies that the mud acid:

- *Should never be used to acidize a carbonate formation* (i.e. the formations with a high calcium content).

- *Must always be used with a pre-flush of hydrochloric acid.* This pre-flush should be of sufficient size (concentration and volume) to ensure that the calcium ions are dissolved (removed) from the formation prior to it being contacted by the mud acid. A typical hydrochloric acid pre-flush volume is half that of the mud acid. It often has the same hydrochloric acid concentration as the main (mud acid) flush.

- *Is always over-flushed* with a dilute (3% wt. or less) solution of hydrochloric acid (HCl) or ammonium chloride (NH_4Cl) (ammonium salts have high solubility).

The clays, micas etc. that are dissolved by the mud acid undergo a series of reactions that result in precipitation of silica gel ($Si(OH_4)$ - a hydrated form of silica). This reaction can be described in simplified form as:

$$HF + \text{'clay'} \rightarrow Si, Al \text{ (in solution)}^{\textbf{fast}}$$
$$HF + \text{'quartz'} \rightarrow H_2SiF_6 \text{ (dissolved)}^{\textbf{slow}}$$
$$H_2SiF_6 + \text{'clay'} \rightarrow Si(OH_4)\downarrow + Al \text{ (dissolved)}$$

Al and Si represents aluminium and silicon ions respectively, the main constituents of clays and micas. The precipitation of silica gel and any other secondary reaction products cannot be avoided, but their effect can be minimised by:

- *Increasing the HCl:HF ratio of the mud acid* to reduce the amount of secondary (re)precipitation in some formations.

- *Returning the well to production immediately after the treatment has finished* to reduce, or even prevent, formation damage since the secondary (re)precipitation reaction occurs slowly.

- *Over-flushing the mud acid deep into the formation* to minimise the effect on the well's inflow performance of the permeability impairment created by the secondary (re)precipitation.

This latter option and the effects of treatment size are illustrated in Figure 12.

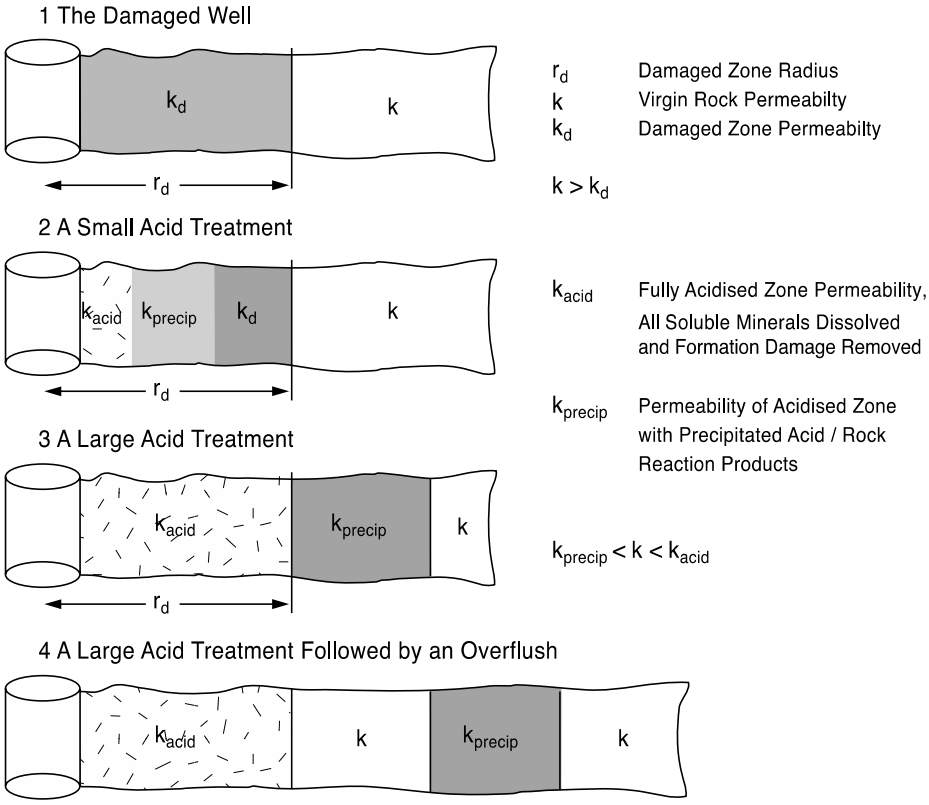

Figure 12 Permeability changes during a mud acid treatment.

8.3 Organic Acids

Acetic acid (CH_3COOH) is sometimes employed when it is desirable to use a weaker or slower reacting acid than hydrochloric acid. Acetic acid has two major advantages:

- It is non corrosive to aluminium and (chrome) steel alloys at temperatures below 90° C. Therefore a corrosion inhibitor is not required for these lower temperature treatments.

- It retains ferric iron in solution as the acid is neutralised ("spends") by reaction with the formation. The chemical name for this effect is sequestration – it prevents the formation of ferric hydroxide precipitate from the depleted acid. This avoids the highly permeability-impairing form of formation damage discussed above, that can occur with hydrochloric acid based stimulation fluids.

Formic acid (HCOOH) behaves in a similar manner to acetic acid, but is even weaker (more slowly reacting) than acetic acid.

Organic acids are often used to replace hydrochloric acid for treatments of higher temperature wells e.g. for formations with a temperature greater than 120°C. Many of the available corrosion inhibitors are less effective at this temperature. Organic acids still require a corrosion inhibitor at this temperature, but the corrosivity is less than that of a hydrochloric acid based treatment fluid at the same temperature.

8.4 Selection of the Acid Composition

The results of a mud acid treatment of an impaired wellbore are pictured in Figure 13. It illustrates how the impairment, formation clays and inter-granular cements are removed by the mud acid and partially replaced by secondary reaction products. However, if the correct acid formulation is chosen, there will be an overall increase in porosity and permeability within the treated zone, leading to increased well inflow performance.

8.5 Laboratory Tests

Laboratory testing in support of a matrix stimulation campaign can include:

- *Identification of the formation mineralogy* by thin sections, X-ray diffraction and Scanning Electron Microscope studies.

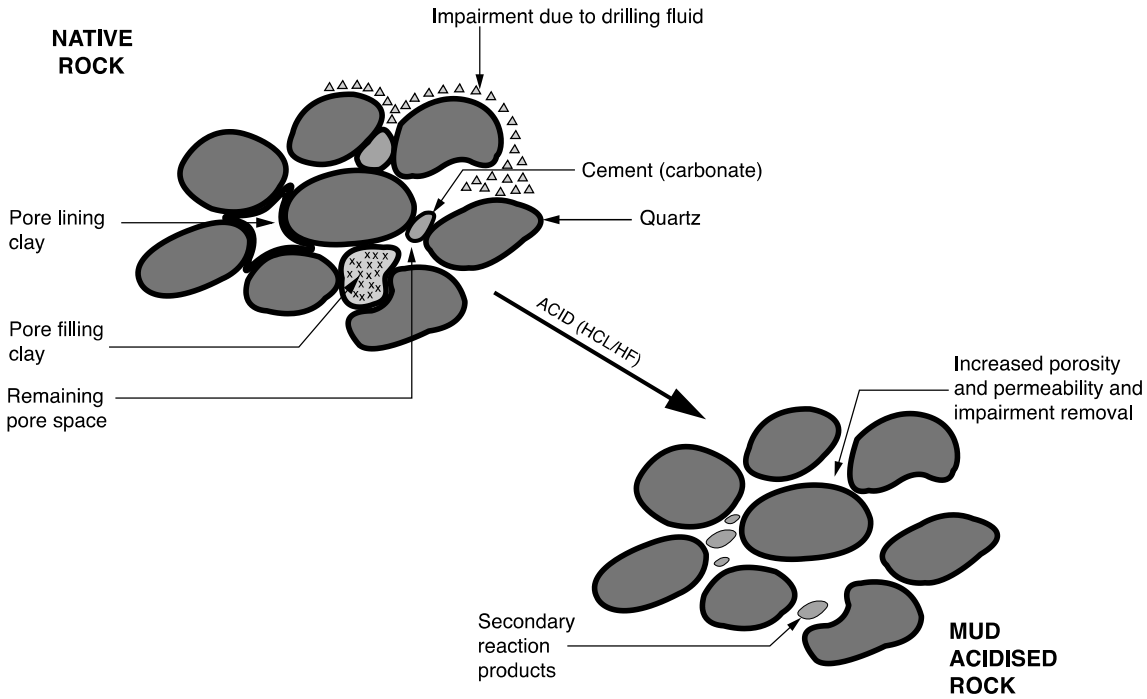

Figure 13 A mud acid treatment increases the formation permeability and reduces formation damage.

- *Petrographic analysis* of formation samples yields information on the type and location of the minerals, porosity, cementation and clays.

- *Fluid-Fluid compatibility tests* using the API RP 42 test methodology. Carrying out these tests will help ensures that all the fluids used are compatible with each other and the in-situ crude oil. Typical tests examine whether a:
  - *Solid "sludge"* is formed by the crude oil on contact with the acid.
  - *Acid/crude oil emulsion stabilised "fines"* can be formed
  - *Viscous oil based mud/acid emulsion* is formed

8.6 Selection of Acid Composition

Formation Characteristics	Acid Recommendation	Comment
HCl solubility > 15%	HCl only	HF causes CaF_2 precipitation. Organic acids or EDTA/ surfactant treatments possible.
10% < HCl solubility > 15%	Increase HCl preflush volume	Ensure all carbonate minerals dissolved prior to mud acid
HIGH PERMEABILITY (> 100 MD)		
High quartz (80%); low clay (5%)	12% HCl - 3% HF	Regular mud acid
High feldspar/illite (> 15%) *	13.5% HCl - 1.5% HF	Avoid fluosilicate precipitation
High clay (> 10%) *	6.5% HCl - 1% HF	Reduce potential migratory fines due to partial dissolution
High (Fe) chlorite clay *	3% HCl - 0.5% HF	Avoid iron dissolution. HCl preflush with Fe sequestrant an option
LOW PERMEABILITY (< 100 MD)		
High quartz (80%); low clay (5%)	6% HCl - 1.5%HF	Reduce migrating fines potential
High feldspar/illite *	6% HCl - 0.5% HF	Avoid fluosilicate precipitation
High clay (> 10%) *	6% HCl - 0.5% HF	Reduce migrating fines potential
High (Fe) chlorite clay *	3% HCl - 0.5% HF	Avoid iron dissolution. HCl preflush with Fe sequestrant an option

* Replace at least half of the HCl by HCOOH for 120° C - 170° C bottom hole temperature
Replace all the HCl by HCOOH for temperatures greater than 170° C
NB 1% wt HCl = 1.3% wt HCOOH

Table 7 Acid selection guidelines.

The ideas presented in the previous section, combined with laboratory core flooding and field experience, have shown the need to adjust the mud acid formulation to the type of formation mineralogy and damage that is being treated. This experience is consolidated in Table 7 (originally from McLeod, 1984, and still applicable!). Salient points of note are:

- Formations with a high (>10%wt), solubility in hydrochloric acid require a larger (hydrochloric acid) preflush. Mud acid should not be used once this solubility level increases to 15%wt or higher.

- Higher permeability formations with a low clay content can be stimulated with fluids containing a higher HF concentration. Increasing clay contents and the presence of certain minerals require lower HF acid concentrations and higher HCl : HF ratios.

- A similar approach is followed for lower permeability formations - except that lower acid concentrations are employed even for the "cleanest" (low clay content) formations.

8.7 Selection of Treatment Volume

The next stage in treatment design is the selection of the treatment volume. This can be based on calculations, models, tests, and field experience when treating wells in the same or similar fields. Often between 50% and 100% of the volumes suggested in Table 8 are used.

Formation Temperature	<150°F	150-250°F	>250°F
Permeability	**Volume of mud acid (US gal/ft perforations)**		
< 20 mD	100	50	50
20-100 mD	150	100	100
>100 mD	200	150	100

Table 8 Mud Acid treatment volume guidelines.

Also practical considerations such as logistics can be considered like e.g.

- How much acid can be delivered to the wellsite? or
- How large is the acid volume pumpable during daylight hours?
- Economics (how much acid can we afford based on the expected gain in hydrocarbon production ?)
- Laboratory core flow testing (acid volume required to increase the permeability by a target amount). The core may be pre-treated to include damage to the core inlet face by the suspected form of formation damage.

8.8 Selection of the Injection Rate

A hydraulic fracture must not be created during a matrix stimulation treatment, otherwise the acid will mostly flow in the fracture without dealing with the near-wellbore damage, resulting in an unsuccessful treatment. The injected fluids *must* be injected below the Fracture Propagation Pressure to ensure that the fluids are injected radially from the wellbore into the matrix (Figure 14).

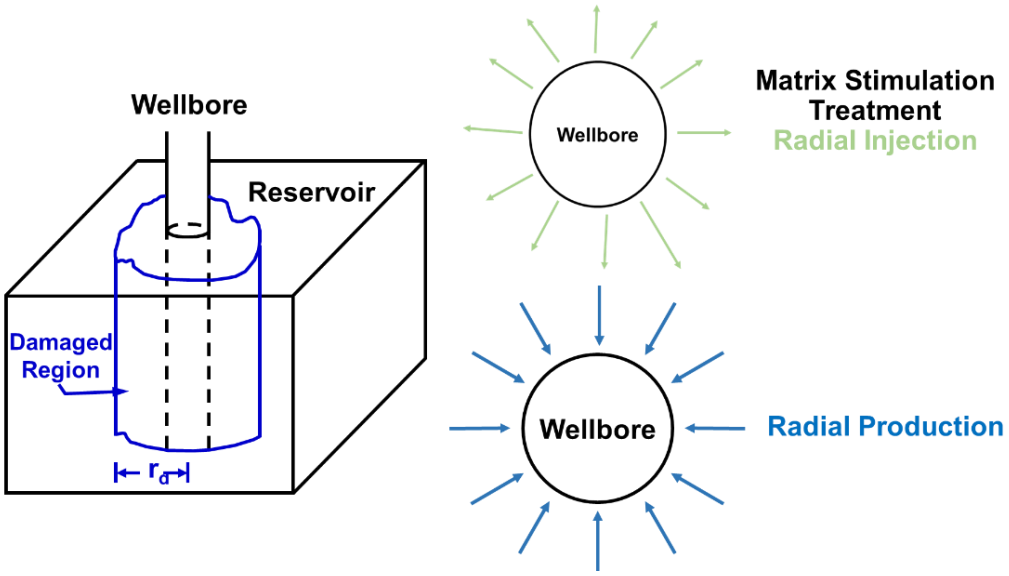

Figure 14 A matrix treatment requires radial injection of the stimulation fluid.

Thus, matrix treatment fluids have to be injected below the Fracture Propagation Pressure (P_{FPP}) (this term is explained in Chapter 9 on Hydraulic Fracturing) to ensure that the fluids are injected radially from the wellbore through the matrix. The maximum allowable injection rate can be calculated from the equation:

$$q_{max} = \frac{141.2*10^{-6}\, k_{av}.h\, (P_{FPP} - \Delta P_s - \bar{P}_R)}{\mu\, \{\ell n\, (r_f / r_w) + S\}}$$

q_{max}	=	maximum injection rate (bpm)
h	=	net treated height (ft)
μ	=	viscosity of injected fluid (cP)
P_R	=	reservoir pressure (psi)
r_w	=	wellbore radius (ft)
k_{av}	=	(average) undamaged permeability (mD)
P_{FPP}	=	fracture propagation pressure (psi)
ΔP_s	=	safety margin (e.g. 150-300 psi)*
r_f	=	radius of injected fluid (ft)
S	=	skin factor

* This safety margin should be larger if the fracture gradient is not well known.

In acidizing the reaction kinetics is controlled by the fluid mass transport (i.e. the rate of acid transport to the mineral surface and removal of the reaction products. This can be either by diffusion and/or by convection) and by the acid-mineral reaction rate. Often one of these two factors is the slowest and thus controls the kinetics. In sandstone acidizing the reaction kinetics is controlled mostly by the reaction rate, that's why experience shows that in most cases the acid injection rate must be as high as the matrix injection conditions allow, so that the acid has a chance to reach the extent of the treatment zone radius before being spent. This allows somewhat uniform removal of damage with a minimum acid volume.

In carbonates the reaction rate is very high, so the kinetics is controlled by the mass transport. This results in an interesting possibility to control wormholing, discussed later. The injection rates in carbonates are also often at maximum as much as the matrix injection conditions allow, but this is not always the case and may also depend on the reaction rate (i.e. acid strength and type, temperature, mineral, etc. E.g. the speed of chemical reactions typically doubles for every 10˚C temperature rise.).

The q_{max} equation above, or similar models, can be used to estimate the maximum injection rate. It is often possible and beneficial to adjust the rate of injection during treatment, because the skin and pressures are dynamically changing. Thus, when measuring e.g. wellhead pressure and injection rate and calculating the bottomhole pressure during treatment, it is possible to estimate the gradually decreasing skin and increase the injection rate accordingly. Once the skin stops changing this may serve as a signal to stop acid injection.

8.9 Selection of Additives

A range of additives to the treatment formulation have been developed to combat one or more of the forms of formation damage associated with stimulation treatments. They can be expensive, especially those added to acid treatments (e.g. the cost of the corrosion inhibitor required when acidizing a high temperature well can often be greater than that of the acid). Further, many of the additives are incompatible with each other and may themselves cause formation damage. The use of each additive has to be justified separately – it should not be just chosen because of the claimed advantages in the service company sales catalogue!

The more important, frequently used additives are summarised below:

- **Corrosion Inhibitors**
  This additive type is almost always required for acid treatments due to the corroding reaction of acid on steel:

  $Fe + 2H^+ \rightarrow Fe^{++}$ (dissolved) + H_2(gas)

  The (acid) corrosion rate increases rapidly with increase in temperature. Further, the corrosion inhibitor loses its effectiveness as the temperature and treatment time increase (due to degradation). A field proven "rule-of-thumb" is that a maximum weight loss of 0.05 lb/ft^2 of tubing area (equivalent to the removal of 0.001 in of the tubing wall thickness) during the treatment duration is acceptable. This implies that the allowable corrosion rate decreases as the acid treatment time increases. Further, the only corrosion should be in the form of a general weight loss type rather than pitting or stress corrosion. The above allows a specification to be developed for the corrosion inhibition of the acid.

  N.B. The "spent" acid produced back after the treatment when the well is returned to production after acidizing clastic formations is often highly acidic and will corrode the tubing at a similar rate to the fresh acid. This is because the corrosion inhibitor has been depleted by reaction with the acid or absorbed on the formation. Injection of extra corrosion inhibitor may be considered during this phase if, for example, the well is being returned to production by nitrogen lifting with a coiled tubing unit.

- **Sequestering Agents**
  Both the ferrous (Fe^{++}) and ferric (Fe^{+++}) forms of iron will precipitate as the acid "spends" (pH increases). They both form an amorphous, high volume iron hydroxide precipitate which is highly efficient at creating formation damage. Fe^{+++} is by far the most insoluble form. Ferric hydroxide already has a low solubility at pH values greater than 2. While ferrous hydroxide precipitation is delayed until the pH rises to values greater than 6. The pH value of ferric hydroxide precipitation onset increases to a value of 6 when mud acid is being used since sequestration takes place due to the presence of the fluoride ion (F^-).

The main source of Fe^{+++} is the acid reacting with rust in the surface tanks, flowlines and millscale on the tubing. The Fe^{++} is mainly (>80%) derived from the formation minerals e.g. chlorite, siderite, pyrite etc.

A number of "sequestering" – or solubilising – agents are available to increase the solubility of iron by forming soluble complexes. The concentration of "sequestrant" required to prevent iron hydroxide precipitation depends on the expected ferric ion (Fe^{+++}) concentration.

The cheapest sequestering agent is citric acid. This has the disadvantage that the maximum concentration allowable – and the maximum amount of iron cations that can be sequestered - is limited by the solubility of calcium citrate. A more expensive alternative, which can be used at higher concentrations, is EDTA (Ethylene Diamine Tetracetic Acid). An alternative approach to preventing ferric hydroxide precipitation is to reduce the Fe^{+++} to Fe^{++} by Erythorbic acid or ascorbic acid (vitamin C).

Fe^{+++} can catalyse the formation of an asphaltenic sludge when the acid contacts some crude oils. This sludge formation is prevented by ensuring the acid's Fe^{+++} concentration is low.

- **Solvents/Mutual Solvents/Surfactants**
  Use of these materials may reduce emulsion formation; but they can also be the cause of very stable emulsion formation. Further, they may render the corrosion inhibitor ineffective by preventing the absorption of the inhibitor onto the steel surface. They can be useful in some circumstances – but their employment needs to be properly justified and a full range of compatibility tests carried out.

- **Nitrogen**
  Nitrogen gas may be added to the treatment fluid to assist flow back of the spent acid and hence a rapid clean up, especially when treating gas wells or depleted zones. Once the well is put back on production and the wellbore pressure decreases, the compressed nitrogen in the pore space expands and helps 'squeezing' the liquids to the wellbore.

9. POTENTIAL FORMATION DAMAGE CAUSED BY MATRIX STIMULATION FLUIDS

The reaction of an incorrectly chosen stimulation fluid with the formation rock and the insitu reservoir fluids, or even previously injected fluids, may generate further formation damage/impairment. Such sources of formation damage, many of which have already been mentioned, include:

- *Deconsolidation of the rock matrix due to the acid dissolving the cementing material that holds the sand grains together.* (Temporary) sand production is often observed when a well is returned to production after an acid stimulation.

- *Generation of migrating, small diameter particles ("fines") which can block the pore throats.* These particles result from the acid only partly dissolving the formation minerals present between the grains. This allows insoluble, small diameter, particles to be created and injected into the formation pore throats, allowing bridging and blockage to occur.

- *The reaction products created by the chemical reaction between the acid and the formation rock are insoluble in the spent stimulation fluid.* This is called secondary precipitation. This precipitation process leads to blockage of the pores and pore throats (impairment). This precipitation often does not occur immediately. As mentioned, available options are to either:
  a. Immediately produce the (spent) acid (i.e. return the well to production) or
  b. Inject the (spent) acid deep into the formation where any precipitation will have limited effect on the well productivity.

- *Fluid incompatibilities.* A matrix acidizing treatment consists of injecting a series of fluids that should be compatible with each other and with the formation fluids i.e. to not form a (solid) precipitate at the reservoir or treatment temperature when mixed in any proportion. Further, both the "fresh" (unreacted) and the "spent" acids that have reacted with the formation must be considered.

- *Acid precipitation of an insoluble sludge when mixed with the crude oil*. This is particularly true for asphaltenic crudes and for acids containing ferric cations (Fe^{+++}). Fe^{+++} cations are normally formed by the reaction of the acid with rust, or ferric oxide, formed by the oxygen corrosion of steel at the surface. Asphaltene sludge precipitation can be avoided by ensuring the (downhole) injected acid has a low Ferric cation content or by injecting a compatible hydrocarbon pre-flush to displace the crude oil away from the wellbore prior to injecting the acid.

- *Surfactants*. Surfactants added to the treatment fluids may create a (highly) viscous emulsion with the crude oil. This low mobility emulsion will be difficult to remove from the formation after the treatment has been completed.
  Pre-screening laboratory tests involve mixing a sample of the treatment fluid and the crude oil and then examining the mixture for emulsion formation. A range of production chemicals (de-emulsifiers) are available to prevent emulsion formation.

- *Wettability changes*. Surfactants can change the wettability of the pore surfaces. An oil wet formation has a lower permeability to oil than the equivalent water wet formation. Once again, any surfactants that are planned to be used should be tested as described above.

- *"Water blocks"*. Significant volumes of water are injected into the formation during the stimulation treatment. This may lead to an increased water saturation (water block) in the near wellbore area which reduces the relative permeability to hydrocarbon due to the increased water saturation. This can take a long time to disappear (months or even years) from low permeability formations.
  It can be minimised by the addition of gas to the stimulation fluid or the (partial) replacement of water by more volatile solvents.

It is clear from above that formulation of the acid and the other fluid flushes employed is the key to ensuring that formation damage is not created by the stimulation treatment, or, if it is unavoidable, it should at least be minimised.

10. ADDITIONAL NOTES ON STIMULATION OF CARBONATE FORMATIONS

As mentioned, acidizing of carbonate formations is different from the acidizing of clastic formations. This is due to their differing physical nature and chemistry. Carbonate rocks:

- Consist of very fine grains exhibiting a vugular or fracture porosity rather than the intergranular porosity shown by sandstones.

- React relatively rapidly with hydrochloric acid while majority of the components that make up a clastic (sandstone) formation are not affected at the same formation temperature. Also, the use of mud acid is prohibited due to the limited solubility of calcium fluoride.

Carbonates are often massive deposits of chalk, limestone or dolomite. Their constituent particles are much smaller than the typical sand grains found in clastic formations. They will have undergone large porosity and permeability reductions during burial and diagenesis. They are often very pure (> 95% wt. carbonate), though they may also include iron minerals, clays and silicaceous materials; resulting in a very variable composition, and hence a variable rate of reaction with hydrochloric acid. The hydrochloric acid concentration and the formation temperature have a large effect on the rate of reaction.

The many possible diagenetic processes can lead to formations with similar chemical compositions having a strength that varies from being very strong to behaving similar to toothpaste. Strong and weak layers can be present a small distance apart. This complicates the planning of well completion – and stimulation – procedures.

10.1 Acid Composition Selection for Carbonate Formations

Hydrochloric acid is used to:

1. *Bypass* drilling or completion damage by dissolving the rock matrix.
2. *Widen* natural fractures or secondary porosity so as to improve fluid conductivity to the wellbore.
3. *Increase* the effective wellbore radius by wormhole formation.

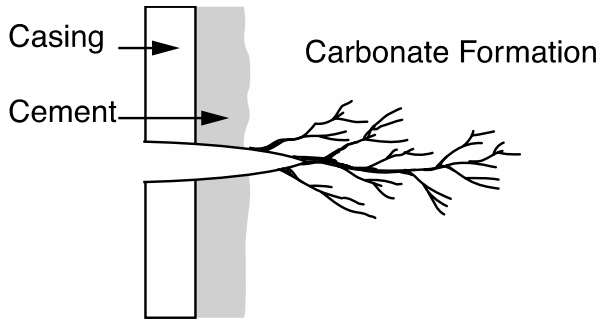

Figure 15 Wormhole formation from a perforation during matrix acidizing.

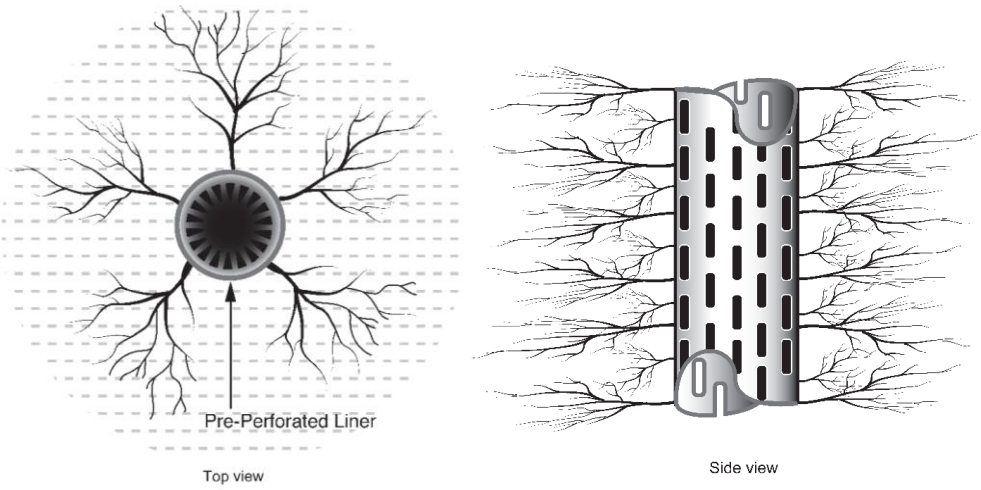

Figure 16 Wormhole formation from a vertical well with 'open hole with a slotted liner' completion in a carbonate formation.

At certain conditions, the acid injected into the formation forms "wormholes" (Figure 15 and Figure 16) rather than dissolving the rock uniformly. "Wormholes" consist of a main channel from which many highly branched structures are formed, similar to fractal growth.

The number and extent of the wormholes depend on the:

- C*arbonate formation's reactivity*. High reaction rates promote few, long wormholes.

- *Acid leak-off rate into the matrix.* This is controlled by the acid and formation fluid viscosities, formation permeability and the overbalance injection pressure. For instance, at a certain moment the growth of a wormhole is halted because the fresh acid leaks off through the branches before being able to reach the wormhole's tip.

- *Presence of higher permeability streaks, fractures, vugs, etc.* which determine the preferred direction of wormhole growth.

Wormhole formation improves the well's inflow performance by providing a high conductivity channel at depth from the wellbore, as well as removing any formation damage on the surface of the wellbore. The density of wormholes rarely matters: their flow conductivity is much higher than that of the matrix, so a few wormholes show the flow performance as good as many. The optimal design should result in the formation of wormholes of certain length with minimum volume of acid needed. There is often an optimal acid injection rate to achieve this, observed experimentally in core tests and manifesting the conditions when the mass transport-controlled wormhole growth is matched by the leak-off rate controlled one. In these core tests acid is forced into one side of a core slab, and its breakthrough on the other side is detected once it etches a wormhole through. The relationship of the injection rate and the acid Pore Volume to breakthrough (typically 1.5 PV) is used to define the optimal acid injection rate for the given well.

10.2 Acid Wash (or Soak) Type Treatments

Wormhole formation or deep acid penetration is undesirable if the treatment objective is to remove a very close near well bore damage (e.g. perforations plugged with drilling mud, cement etc.) that might be present in a new completion or after a workover. This is because a large fraction of the acid is consumed forming wormholes rather than removing this type of damage.

Wormhole formation is avoided by performing an acid wash, or soak, treatment with a very low injection rate (<0.0002m^3/min/m) aided by the use of:

- *The highest possible HCl acid concentration* (max 32% wt.) permitted by corrosion considerations for the planned treatment time (10 hours or longer);

- *A coiled tubing* to place a volume of acid, equal to the casing volume of the perforated interval.

11. DIVERSION OF STIMULATION FLUID

Once the type, rate and volume of the treatment fluid have been selected, the fluid placement strategy should be chosen. It is no less important than any other considerations. Typically, the formation is heterogeneous, so injecting the acid into the net pay will ironically result in it flowing mostly into the least damaged, most productive intervals, leaving the ones needing it most virtually untreated! Even if the formation is homogeneous, once the first interval or perforations start cleaning up, they will often accept most of the remaining treatment fluid.

Generally, two options are available to pump the Treatment Fluid into the Well:

1. **"Bullheading**": This is a treatment which is pumped down the production tubing in order to force the tubing fluid into the formation. The treatment – particularly if it employs acids – can displace rust, scale, pipe dope, etc. present on the tubing's inner wall into the formation; leading to formation damage. Sometimes the matrix treatment is carried out prior to running the tubing. This can be even worse with dried mud, cement, etc. possibly being present on the casing wall. This can now also create formation damage along with the above.

   If the formation pressure is sufficiently high, or artificial lift is installed, it is possible to pre-clean the completion tubing with an acid wash a.k.a. 'pickling'. This involves injecting into the tubing a volume of acid – usually equal to 20% of the tubing contents – and displacing it until the leading front of the acid is a safe distance above the top perforation. The acid, along with the dislodged, potentially impairing particles, is then produced back (or could be circulated back if e.g. coiled tubing is used in this operation) to the surface and discarded.

2. **Using a Coiled Tubing:** The coiled tubing (CT) is inserted into the well and its end positioned opposite the perforations and the treatment fluid is pumped. Note that:
   - The inside of the CT will have been thoroughly cleaned and the inside sprayed with corrosion inhibitor by the Service Company after its previous treatment. Hence pre-cleaning the completion tubing by "pickling" with acid at the wellsite may not be necessary.
   - However, a CT has a smaller internal diameter than the production tubing. This will often limit the maximum pump rate (due to extra friction from the acid's high flow velocity in the CT compared to the production tubing).

Once the pumping option is selected, it is reasonable to consider fluid diversion methods that would direct the fluid into all of the pay zone interval by interval, ensuring proper placement.

11.1 Diversion ensures the Acid treats all the Formation Layers

Most formations are heterogeneous with the perforated interval consisting of multiple formation layers with a range of permeabilities and differing levels of damage skin. The treatment fluid injection rate into each layer will be governed by the radial flow equation if the pressure in the wellbore is very similar for all the layers. Figure 17 shows that by far the highest proportion of the acid is injected into the middle, high permeability layer (Zone B). The tendency for the acid to be injected into this layer is also accentuated due to this layer having the lowest skin value due to a shallow depth of formation damage.

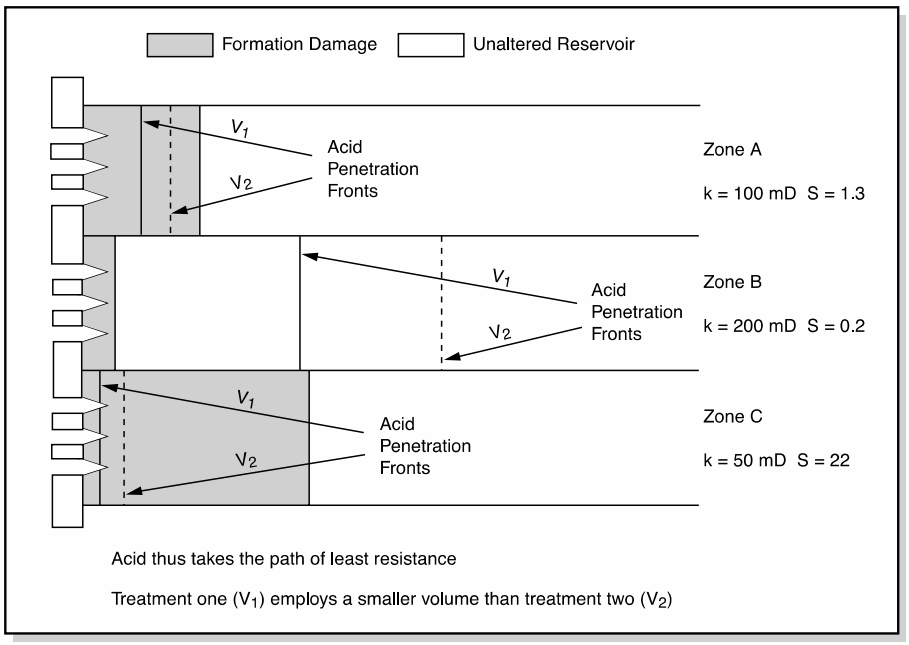

Figure 17 Matrix (acid) treatment profiles for a heterogeneous formation.

Figure 17 shows that the formation damage in zone B alone was removed by the treatment employing V_1, a small treatment volume; while doubling the treatment volume to V_2 does not allow the acid to remove the formation damage in Zones A and C.

Note: The injection rate into a particular layer, relative to the other layers, increases rapidly once the formation damage has been removed by the treatment. Obtaining an even distribution of the (acid) treatment will be further complicated by the layers having different pore pressures.

- *Feel free to attempt Tutorial 4.*

The following solutions are suggested:

1. **Coiled Tubing Matrix Treatments** using a CT with a:

   a. *Rotating spray head with the fluid exit ports at right angles to the tubing.* **All** the formation layers in an openhole or a perforated completion can now be sprayed with a high pressure jet of treating fluid by moving the CT along the length of the completion interval while spotting acid.

b. *Single or dual packer* (Figure 18). The deflated packers are small enough to pass through the tubing. They can be expanded and deflated many times, allowing each zone to be treated separately.
Note: The spacing between the packers is constant while the CT is in the well.

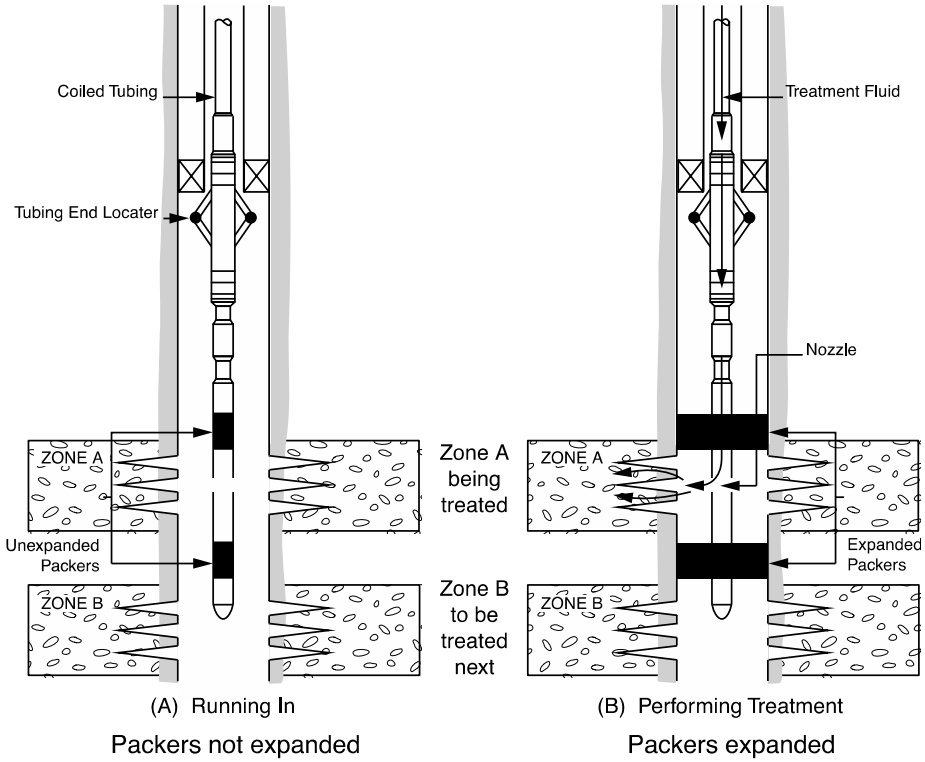

Figure 18 Selective treatment of two zones using a coiled tubing with a dual packer.

2. "Bullhead" matrix treatments can employ a diverting agent during the treatment to (temporarily) block the perforations with the greatest injectivity. This increases the well injection pressure, ensuring more acid is injected into the remaining perforations, resulting in a more even fluid placement in different layers.

Suitably sized solids, viscous gels, emulsions or foams (see the note above on retarded acids) have all been used as diverting agents. The agents are forced with the fluid into the most fluid-accepting perforations, thus temporarily plugging them and forcing the fluid to other perforations, and so on. The diverting agent must "disappear" once the matrix treatment has finished, for example, by (1) the fluid's high viscosity disappearing when it warms up to reservoir temperature or pH increases or (II) using a solid diverting agent that temporarily blocks the perforations during the treatment and, later on, is dislodged (e.g. ball sealers) or dissolves in the reservoir fluid or acid (e.g. benzoic acid flakes, resin beads or fibres, calcite particulates, etc.).

- **Ball Sealers**
  Ball sealers are nylon covered balls sized so that they can seal the perforations. Their mode of action is illustrated in Figure 19. It is found in practice necessary to pump a 30% – 100% excess of balls above the number of perforations to be sealed. The density of the ball may be chosen so that once the treatment is over, it is either:
  - **Buoyant** (floats upwards in the treatment fluid due to the ball having a slightly lower density.) or
  - **Sinking** into the rat hole (i.e. ball density is greater than the treatment fluid).

The ball density relative to the produced fluid controls whether the ball is produced back to the surface or stays at the well bottom after the treatment is finished.

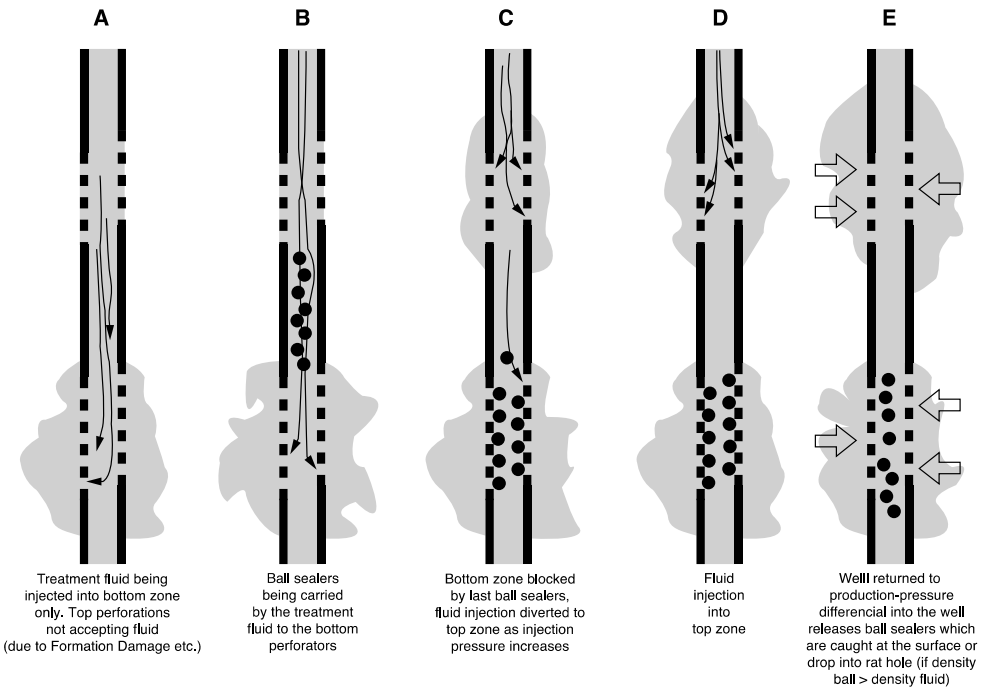

Figure 19 Ball sealer diversion.

- **Viscous Fluids (gels and foams)**
  The idea behind the use of viscous fluids is that they increase the flow resistance in the layer taking excessive amounts of treatment fluid so that the fluid is diverted into a new layer. The skin (S_{vis}) due to this viscous fluid can be estimated by an equation similar to the Hawkins formula discussed earlier:

$$S_{vis} = \left(\frac{\mu_{visc}}{\mu_{form}} - 1\right) \ln \frac{r_{vis}}{r_e}$$

where μ_{visc} = viscosity of the viscous fluid
μ_{form} = viscosity of the formation fluid
r_{visc} = depth of the invasion of the viscous fluid
r_e = well drainage radius

The diversion process is only effective if the viscous fluid is highly shear thinning i.e. its viscosity increases rapidly as its flow velocity decreases at greater depths of injection. This allows it to form a viscous "plug".

- **Particles that form a low permeability film on the wall of the perforation or completely fill the perforation tunnel.**

  Both techniques are illustrated in Figure 20. The permeability of the diverting agent is mainly dictated by its particle size. Its presence in a perforation will reduce the injectivity into that perforation, reducing the rate of treatment fluid injection and increasing the flowing wellbore injection pressure.

This will divert the injection stream into another zone. Further quantities of the diverter material may be added continuously or intermittently in batches.

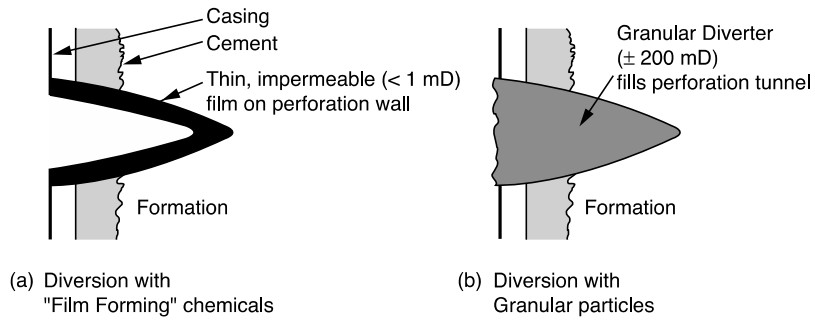

Figure 20 Diversion with (a) film forming chemical or (b) granular particles.

The concept behind the choice of materials used for these two diverting techniques is that they must be capable of:

- Being prepared in the required range of particle sizes (to form the low-permeability film, similarly to how filter cakes work),
- Be stable in the treatment fluid,
- Disappear (dissolve or sublime in the produced fluids) from the perforation so that it becomes fully open to flow once the well is returned to production and
- Be non-toxic, cost-effective and readily available.

Clearly, a higher concentration of the granular particulate material is required when a film forming chemical is used. Treatment design is difficult when using either of these concepts - the injection profile can be made more uneven ("anti-diversion") if an inappropriate treatment design is used. In the extreme case, the excessive use of the film forming chemicals can result in a complete loss in well injectivity before all the treatment has been pumped (very embarrassing when acid is in the tubing!).

Typical chemicals used for both particulate and film forming diversion agents, by preparing them in the correct particle size ranges, are:

- Benzoic acid (soluble in water, oil and gas),
- Sodium Chloride (NaCl or rock salt) crystals (soluble in water) and
- Oil soluble resin particles.
- Calcite particles

Mechanical separation using conventional techniques.

These techniques include control of the point of fluid injection by use of retrievable bridge plugs placed in packers set between completion zones (Figure 18), dual packers on a work string (similar to Figure 21), sequential 'just-in-time' perforation, etc.

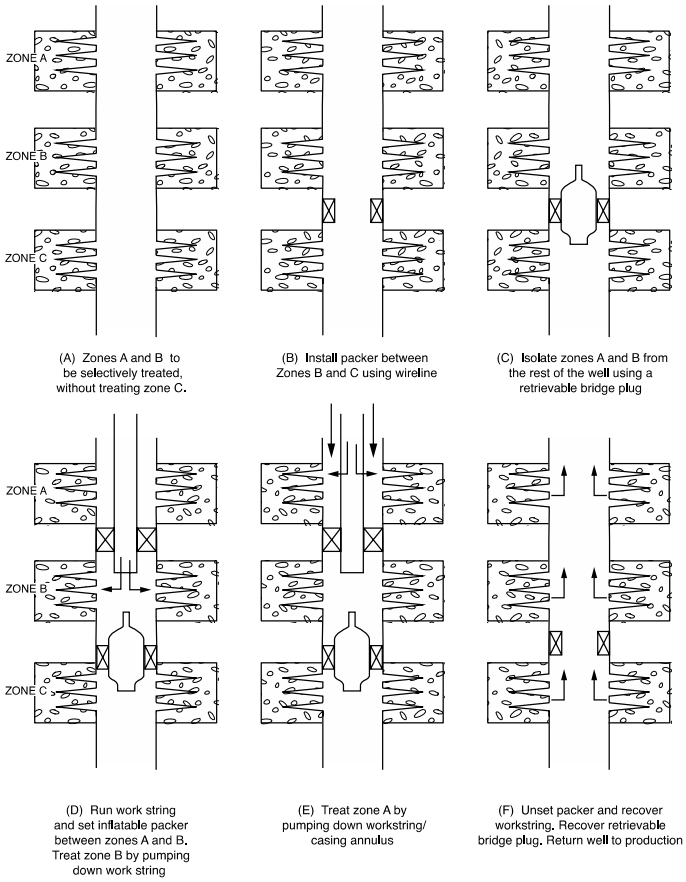

Figure 21 Use of retrievable packers and bridge plugs to separately treat the upper two zones of a multi zone well.

12. ACIDIZING OF SPECIAL WELL TYPES

Some examples of well types requiring special treatment techniques are listed below.

12.1 Gravel Packed Wells

This well type poses a number of areas where fluid inflow can be impeded (the screen, perforations, gravel, gravel/sand interface and the near wellbore formation). Dedicated treatments require identification of the type and location of the formation damage. For example:

The screen: removal of material plugging the screen requires placing (or "spotting") the acid across the entire screen length while minimising inflow into the gravel pack. This is best done by use of a Coiled Tubing which is moved across the completion while pumping acid. A small acid volume is used e.g. 120% of the wellbore completion volume.

The gravel: removal of residue left from the viscosifier. Viscosifier residues are normally best removed with solutions of enzymes (for formation temperature <65˚C), hypochlorite (a bleach) or 2% wt hydrochloric acid (at higher temperatures). A treatment volume equal to 120% of the gravel pack volume should be used together with a diverting agent which passes through the gravel pack sand and filter out on the formation.

Near wellbore formation damage: this should be treated in a similar manner to perforated completions, except that the available diversion techniques are much more limited due to the presence of the gravel pack.

12.2 Horizontal Wells

Treatment of horizontal wells is no different from conventional wells with respect to the candidate and fluid selection criteria concerned. Many of the conventional diversion treatments (ball sealers / chemical diverters) would not be successful in the horizontal orientation since the treatment fluid / diverter density differences will result in shutting off either the top or bottom of the completion section. Dual Packer diversion is not effective in the uncemented liner or screen completions because of the presence of the open annulus. Diversion with a viscous fluid (foams or gels) is a possibility, but the very large volumes required may make them operationally impractical. Spotting acid along the completion interval with coiled tubing is another option.

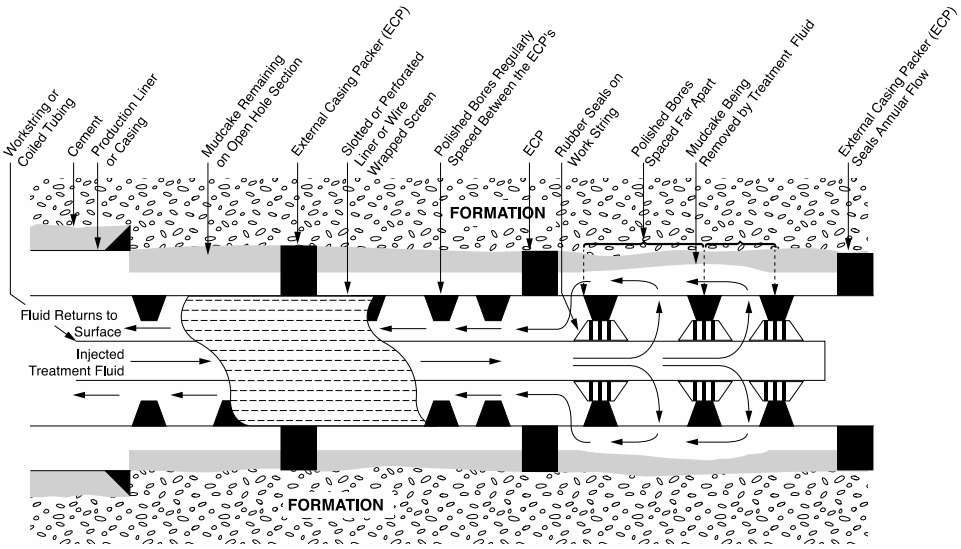

Figure 22 Removal of mudcake from behind slotted liner using washpipe and seals.

Mechanical diversion, using the set up shown in Figure 22, is a possibility. The horizontal well has been divided into a number of sections using external casing packers (ECPs). Rubber sealing elements installed on the outside of the CT seal against a polished bore installed at regular intervals inside the liner or screen. This arrangement allows for the completion zone between the ECPs to be selectively treated in two manners:

- Circulation of the treatment fluid past the mud cake, when the flow returns to the surface via the CT/tubing annulus. This will aid removal of the mud cake;

- Injection of the treatment fluid into the formation by closing the wellhead valve which allowed the return flow.

The regular arrangement of ECPs and polished bores allow the treatment to be repeated along the length of the completion interval.

This method requires the installation of a large number of ECPs and polished bores during the initial completion of the well. This is expensive (increasing the well cost) and also presents an increased risk of failure during the initial completion. It is also often not known in advance whether – and at which point in the horizontal wellbore – such treatments will be required.

12.3 Naturally Fractured Formations

(Natural) fractures often have a conductivity many times that of the formation. In fact, in many carbonate formations the matrix has a very low permeability and almost all the production comes from the fracture(s). Stimulation may have two possible objectives:

- Removal of damage to the fracture conductivity by drilling mud or cement;
- Enhancing the (natural) fracture conductivity by dissolving the cementing materials deposited in the fracture.

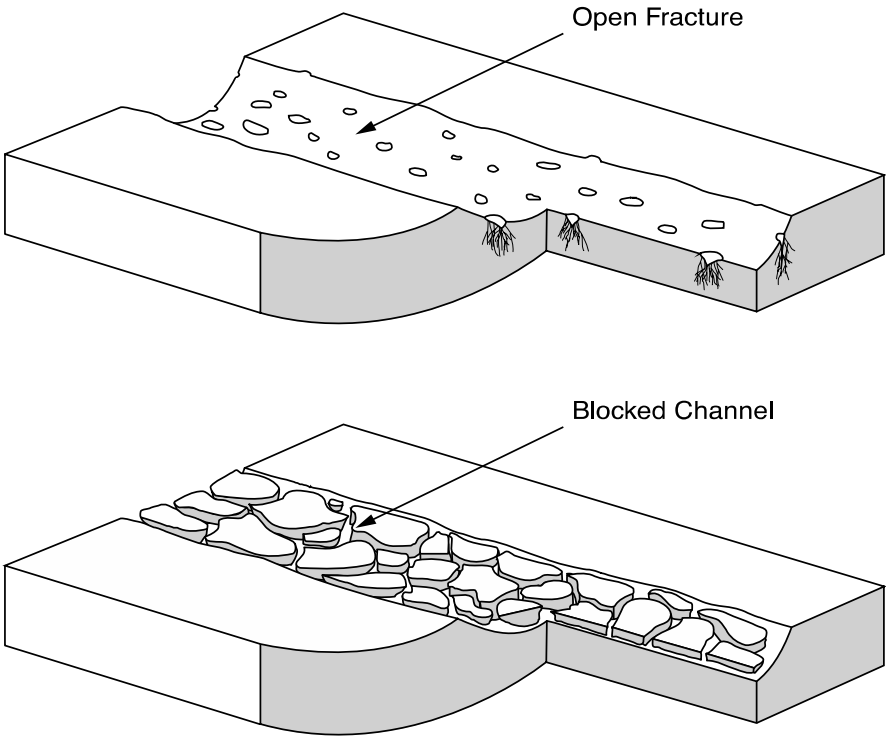

Figure 23 (Acid) insolubles remaining after the acid frac
of impure carbonate formation will block channel if not removed.

As usual, fluid acid selection depends on the treatment objectives. A key point in the fluid selection procedure is whether the fracture contains materials insoluble in hydrochloric acid – if so these insoluble materials will remain in the fracture and block the created permeability. This is illustrated in Figure 23. The top picture shows a clean open channel created by acidizing a pure, fractured limestone. Its appearance is contrasted with that of a similar experiment carried out on an impure, silty limestone (lower picture). In the latter case the channel has been blocked by insoluble particles remaining after the acidization is completed. These particles can be mobilised by the use of a silt suspending agent (a surfactant) so that they are flushed out of the fracture when the well is returned to production *(similar effects are observed when creating wormholes during matrix acidizing treatments of impure carbonate formations).*

Ball sealers can be used to divert the acid treatment from one fracture to another if more than one fracture is connected to the wellbore. In addition, the pump rate can also be used to aid acid placement within the fracture.

- Low pump rates (and hence long contact times) enhance removal of mud cake/cement etc. in the near wellbore region;

- High pump rates – even exceeding the fracture propagation pressure – encourage removal of fracture filling materials from at depth from the wellbore

➢ *Feel free to attempt Tutorial 5*

13. RECOMMENDED READING

1. "Production Operations", Volume 2, 4th Edition, by Allen, T., and Roberts, A., OGCI, 1993
2. "Petroleum production Systems" by Economides M., Hill A. & Economides C.; Prentice Hall, 1994.
3. "Reservoir Stimulation", 2nd Edition, by Economides, M. and Nolte, K.; Prentice Hall, 1989.
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6. "Well Performance" 2nd edition by Golan M. & Whitson C.; NTNU,1996.
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8. "Petroleum Well Construction" by Economides, M.J., Watters, L. T. and Dunn- Norman, S. Published by John Wiley & Sons Ltd., 1988
9. "Petroleum Engineering Handbook for the Practicing Engineer", Volume 2 by Mian M. A.; PennWell Books, 1992.

CHAPTER 9: HYDRAULIC FRACTURING

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LEARNING OBJECTIVES

(All Examinable)

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

- List the nomenclature of propped Hydraulic Fracturing (HF)
- Explain the role of Rock Mechanics in supplying basic design data for an HF treatment
- Identify the key elements of the Rock Mechanics in Fracture Initiation and Propagation
- Analyse Fracture Propagation Pressure Record to derive basic design data
- Discuss the importance of the perforation programme design to the success of an HF treatment
- Distinguish between the different Fracture Propagation Models
- Explain how to select fracturing materials (fluids/proppants) for an HF treatment
- Discuss the factors influencing Hydraulic Fracture geometry (fracture shape and length)
- Critically describe the Hydraulic Fracture Treatment Design Procedure
- Describe the stages of a Hydraulic Fracturing Treatment operation
- Describe the factors which control the Folds of Increase (FOI) factor achievable by HF
- Relate FOI to Net Present Value economics as a function of treatment size in order to optimise HF treatment design
- Explain the principles of and the need for Tip Screen Out fracturing
- Explain how unconventional reservoirs are fractured

1. INTRODUCTION

Propped Hydraulic Fracturing (a.k.a. 'fracture job', 'fracking', 'fraccing', 'fracing') is a key technology in petroleum engineering. Many conventional wells are fractured to improve productivity, whereas in the cases like tight or shale (a.k.a. 'unconventional') gas and oil fields hydraulic fracturing is the game changing technology enabling economic development of these reserves.

Propped Hydraulic Fracturing is done by pumping a volume of viscous fluid (a.k.a. 'pad') into the completion interval at the wellbore pressure above the formation fracture pressure. This high-pressure fluid pumping results in the formation break down and the rock parting along the plane perpendicular to the minimum compressive stress so that a two-winged, hydraulic fracture is formed. This fracture is then filled with a high conductivity proppant (usually it's well-sorted sand) which holds the fracture open (maintaining a high conductivity path to the wellbore) after the treatment is finished and the fracture fluid has leaked off into the formation (Figure 1a). Otherwise, the fracture would have closed when the pumping is over, without any effect on the well productivity.

The conventional propped fracture typically can have an average width of around 0.25 in and a length of a few hundred to thousand feet, depending on the design technique employed and the size of the treatment. The fracture offers a 'highway' for the reservoir fluids flowing to the wellbore, accesses deep or not-connected reservoir reserves, bypasses wellbore damage, and increases the wellbore-reservoir interface (e.g. a fracture 100 ft high and 1000 ft long has the area contacting the reservoir (two faces) of 2x100x1000 = 200,000 ft^2).

Fracture treatment is a complex operation requiring specialist equipment, personnel, and materials (a typical conventional fracture needs tens to hundreds of thousands of gallons of fracturing fluid, and tens to hundreds of tons of proppant). The fracture treatment cost is high and often comparable with the well drilling cost. However, the increase in production is also high, e.g. in tight reservoirs the increase in well productivity is typically in the range of 1.5-30 times. It is therefore common to economically evaluate and optimise such treatments from the point of view of the long-term project net profit (Net Present Value NPV).

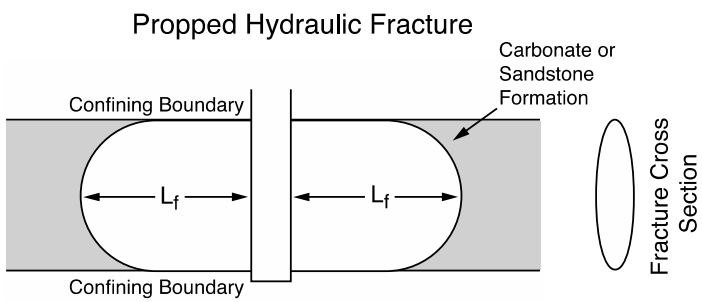


Figure 1a: Fracturing Concepts: Propped Frac

In carbonate reservoirs, in addition to the same propped fracturing technology, another option is to pump hydrochloric acid (with or without preliminary pad): it etches non-uniform channels on the fracture surface, which serve as a highly conductive path when the fracture closes. Hence no need for proppant in this case.

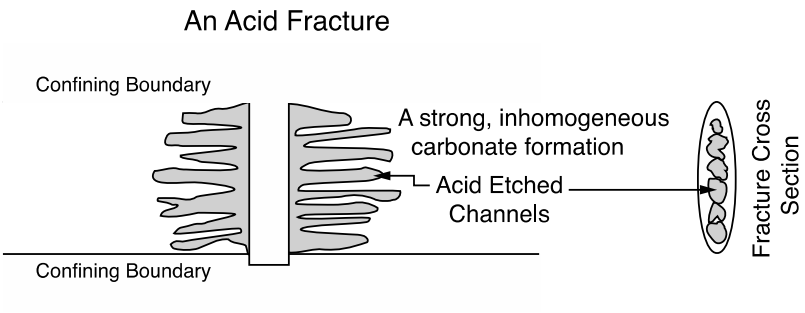


Figure 1b: Fracturing Concepts: Acid Frac

Both types of fracturing treatments create highly conductive paths from deep in the reservoir to the wellbore.

Propped hydraulic fracturing is aimed at raising the well productivity by increasing the effective wellbore radius for wells completed in low permeability carbonate or clastic formations. The radial well inflow equation:

$$Q = \frac{2\pi\ kh\left(\overline{P}_R - P_{wf}\right)}{\mu_o B_o \left\{\ell n\left(\frac{r_e}{r_w}\right) + S - \frac{3}{4}\right\}} = \frac{2\pi\ kh\left(\overline{P}_R - P_{wf}\right)}{\mu_o B_o \left(\ell n\left(\frac{r_e}{r'_w}\right) - \frac{3}{4}\right)}$$

shows that the well production rate (Q) after fracturing can be increased by:

- **Increasing the formation flow capacity** (k.h) {the fracture may increase the effective formation height (h) connected to the wellbore, and/or connect with a formation zone with a higher permeability (k)};

- **Bypassing** flow effects that increase the skin (s) e.g. near wellbore formation damage;

- **Increasing the effective wellbore radius** (r'_w) by decreasing skin (typically S_f in conventional fractured wells is around -6), which itself is a function of the conductive fracture length L_f (see Figure 2a). This is due to the highly conductive path created by the fracture, and is normally the major benefit of fracturing.

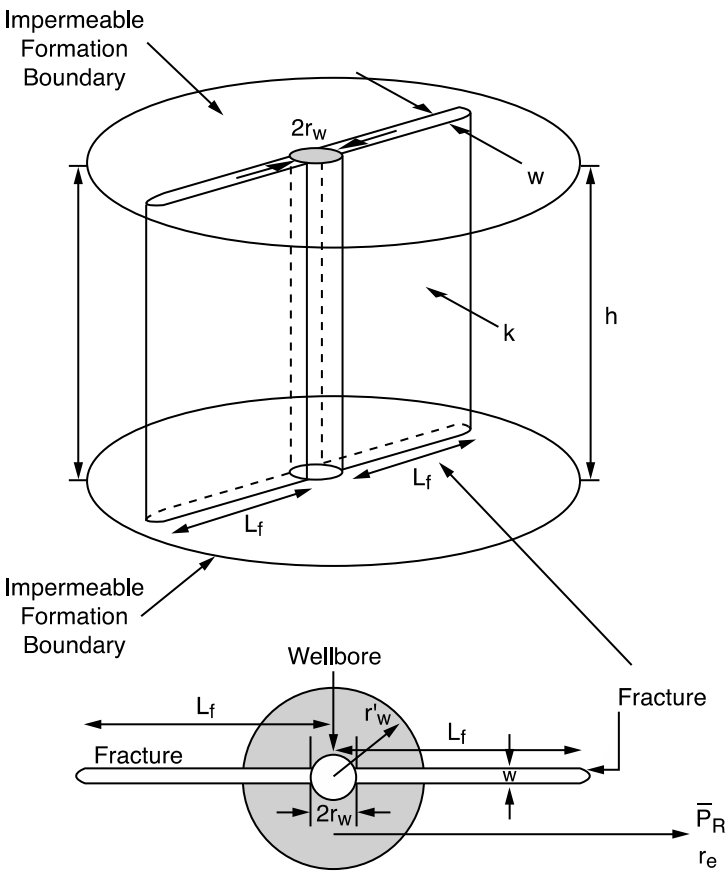


Figure 2a Propped hydraulic fracture geometry

N.B. Simplified models assume that the two wings of the fracture are symmetrical (same height and length).

If the hydraulic fracture has infinite conductivity i.e. the pressure drop along its length due to flow is negligible, then:

$r_w' = L_f/2$

Thus, high conductivity fractures allow fluids to flow to the well whose effective radius has been enlarged to a value equal to half the single wing fracture length. (In low permeability formations < 1mD a reasonable fracture conductivity can often be assumed as relatively 'infinite' since it is much higher than the reservoir conductivity).

2. TYPES OF FRACTURE STIMULATION TREATMENT

Some of the main variants in fracturing technology are depicted for vertical wells in Figure 3. Their areas of application have been summarised in Table 1.

Reservoir Type	Treatment	Candidate Well	
		Skin (S)	Permeability (k)
Sandstone or Carbonate (Figure 9 a)	Conventional Proped Fracture	High / Low	Low
	Skinfrac*	High	Medium
	Matrix Acid	High	High
	None	Very Low	High / Medium
Naturally Fractured Reservoirs filled with Calcite Cement (Figure 9 b)	HCl Acid pumped near or above Fracture Propogation Pressure (FPP)	Low / High	Low (Matrix)
Inhomogenous Carbonates (Figure 9 c)	HCl Acid pumped above FPP	High / Low	Low
Homogenous Carbonates (Figure 9 d)	WISPER+- Pump Visious Pad follow by HCl Acid. BOTH above FPP	High / Low	Low
	CFA∅- Pump Visious Pad above FPP, follow by HCl Acid just FPP.	High / Low	Low

* Skinfrac - creation of a short, highly conductive fracture for treating high permeabilty formations
+ WISPER - Wide Spaced Etched Ridges
∅ CFA - Closed Fracture Acidising

Table 1 Treatment selection guidelines *(refers to Figures 3 instead of Figures 9)*

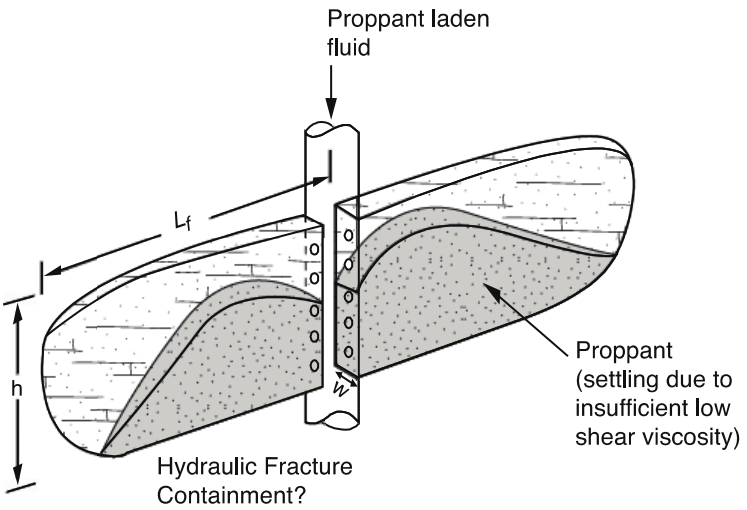


Figure 3***a*** Propped hydraulic fracturing for sandstones and carbonates

Figure 3a illustrates a propped hydraulic fracture treatment. Propped hydraulic fracturing is most common and is applicable to both sandstone and carbonate formations. Proppant transport and hydraulic fracture containment within the pay zone are key issues to be addressed during the treatment design. The fracture closes on the proppant which will form the required highly conductive channel from the reservoir to the wellbore.

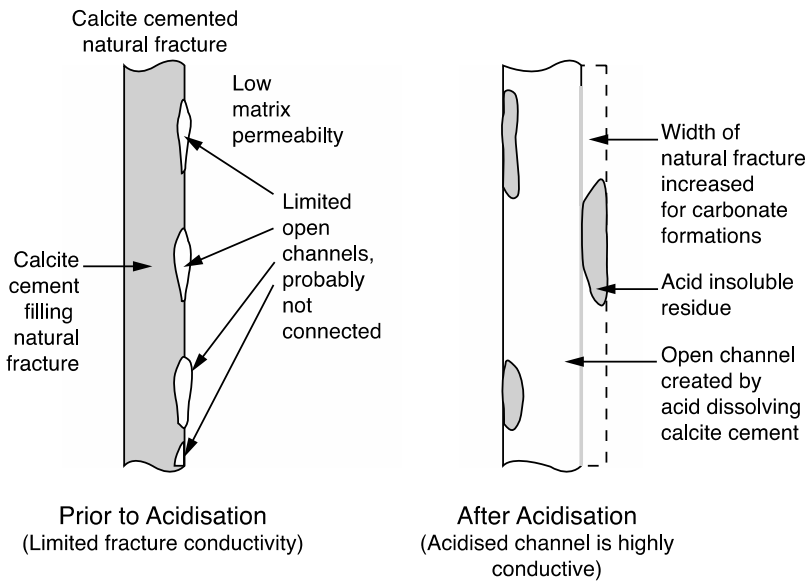


Figure 3***b*** Acid treatment of a low permeability formation with natural fractures filled with calcite cementing material

Figure 3b illustrates the increased conductivity achieved by pumping hydrochloric acid into a naturally fractured carbonate formation and thus reactivating the natural fractures.

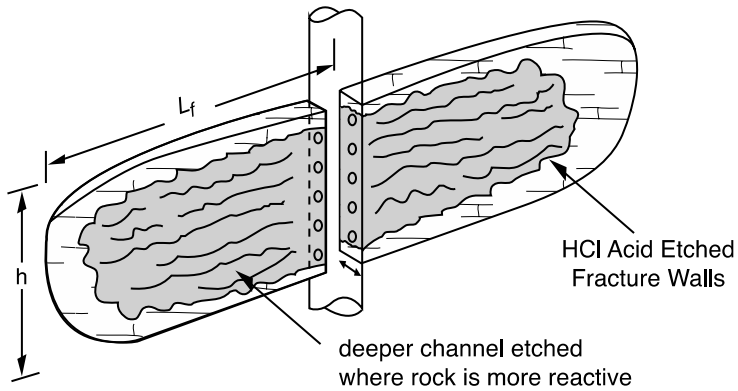


Figure 3***c*** Acid fracturing for inhomogeneous carbonates

Figure 3c illustrates an (HCl) acid fracture treatment of an inhomogeneous, carbonate formation. These naturally occurring inhomogeneities will ensure that some parts of rock will react more quickly with the acid than others - resulting in a deeper etching of the fracture wall at this point. Providing the formation is strong and inhomogeneous enough, the (deeper) etched channels will remain open after the treatment is finished, forming a conductive flow path to the wellbore. The resulting Dissolved Rock Equivalent Conductivity (DERC) is very much the function of the average, etched fracture width, which itself is a function of the acid reaction rate, dissolving power, pore pressure, etc. Various, complex geomechanical - geochemical models exist used to predict and estimate such fracture performance.

N.B. the carbonate acid formulation selection guidelines (see Chapter on "Acidizing" and other Matrix treatments) should be followed for both (Figure 3b) and (Figure 3c) type treatments.

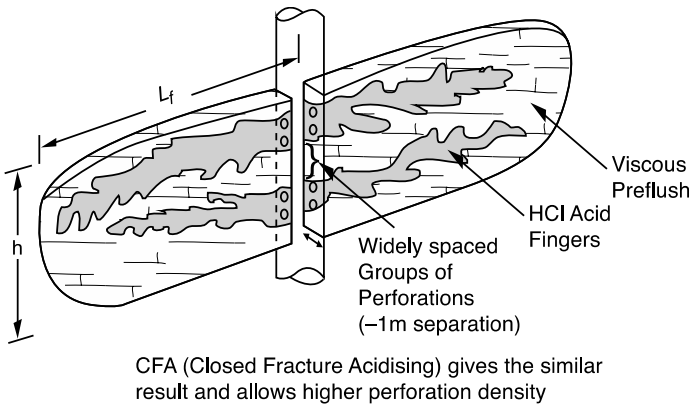


Figure 3***d*** WISPER (Wide Spread Etched Ridges) process for acidizing homogenous chalks

Figure 3d illustrates the results of a treatment designed to create a number of separate, acid etched fingers. Soft, homogeneous carbonates (e.g. chalks) require the artificial creation of the necessary inhomogeneities. (Otherwise, the acid may react with the fracture faces uniformly, without etching channels, and thus the high conductivity pathway will disappear once the fracture closes.) This is done either through:

- The low viscosity acid fingering through the high viscosity gel preflush (pad) at pressures greater that the Fracture Propagation Pressure (FPP) (e.g. the WISPER or Widely SPaced acid Etched Ridges process) or

- By pumping the acid at just below the FPP (CFA or Closed Fracture Acidizing process). The special perforating procedure (widely spaced groups of perforations) illustrated for WISPER is not required for CFA.

The relative increase in production achievable by placement of a hydraulic fracture is much greater in the case of low permeability formations (Figure 2b). Thus, hydraulic fracturing often makes sense in medium-to-low permeability reservoirs (<50 mD) since the higher-permeability reservoirs have sufficient deliverability on their own. This conventional fracturing is discussed first in this chapter.
However, a special type of fracturing technology (Tip Screen Out TSO fracturing) exists that is suitable in high permeability reservoirs, as will be explained afterwards. This is used in e.g. 'skin fracing' (the creation of short but highly conductive fractures) applied to high-to-medium permeability reservoirs (k >100 mD), frack-packing, etc. "Skinfrac" type treatments, as their name implies, are intended to merely bypass the skin zone i.e. the formation damage zone. As for the increased well inflow due to the increased effective wellbore radius (i.e. the wellbore-reservoir contact): it is often not so high and important because TSO fracs are carried out in formations with high formation permeability that can deliver fluid to the wellbore with or without a highly conductive pathway of fracture equally well.

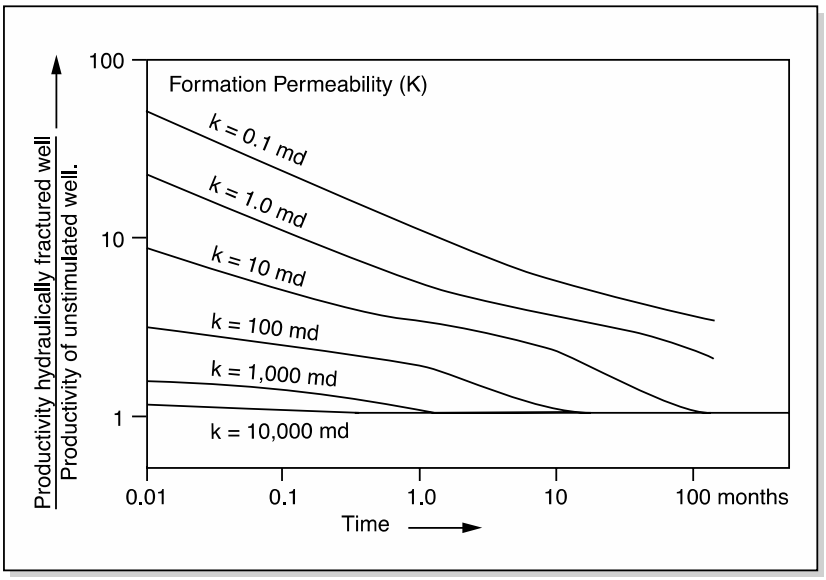


Figure 2b Production increase due to 150 ft long hydraulic fracture with a flow conductivity of 8,000 mD.ft

Unconventional fracturing (i.e. fracturing of unconventional reserves: shale oil or gas reservoirs with nano-Darcy -scale permeabilities) is explained last in this chapter.

- *Feel free to attempt Tutorial 1*

3. A PROPPED HYDRAULIC FRACTURING TREATMENT

The major steps needed to carry out a propped, hydraulic fracture treatment are summarised in Figure 5 and below:

1. Pumping the 'pre-pad': the initial, small, sacrificial ('spurt loss') volume of clay-compatible water (or HCl acid in case clean-up of perforations is also needed) at high pressure to break down formation at the wellbore and initiate a fracture.

2. This is immediately followed by pumping the 'pad': the fracturing fluid, also pumped at a sufficiently high pressure to overcome the rock stresses in order to further propagate a fracture. The fracture cannot be created infinite: as the fracturing fluid is flowing along the fracture from the wellbore to the tip (because the leak off is the highest at the tip), part of it leaks off into the formation from the fracture faces. Even though the leak off rate from a given fracture face area decreases with time, as the fracture keeps growing its face area increases and the overall leak off rate increases, so much so that at some point the fluid will no longer be able to reach the tip at a sufficient pressure and the fracture propagation stops. Pumping at a higher rate may be problematic due to the pressure and rate constraints of the wellbore and equipment.
   (The fracturing fluid properties are conditioned to ensure efficient fracture creation - low fluid loss and tubing head pressure values are frequently achieved by use of a viscous, shear thinning, water based, cross-linked gel.)

3. Once the hydraulic fracture long, and more importantly, wide enough to accept proppant, is created, proppant is added to the fracturing fluid being pumped in, and the resulting proppant slurry fills up the fracture at a gradually increased proppant concentration. Inside the fracture, as the base liquid from the slurry leaks off on its way to the tip, the slurry dehydrates and therefore its proppant concentration further increases. Ideally, when the pumping is stopped and the rest of the liquid has leaked off, this should result in the fracture uniformly filled with proppant to "hold it open" so as to provide conductivity for fluid flow during production. This is not always the case as some proppant may settle on the way, or not reach the tip. Thus, the eventual **propped fracture** dimensions: length and width, may be smaller than those of the **hydraulic fracture**. It is also important to avoid the screen out effect: if the proppant slurry prematurely dehydrates then the proppant sand can bridge the fracture and interrupt its propagation. It will manifest itself as a rapid increase in the injection pressure, prompting the job stop and clean out of the wellbore full of proppant. *(The chances of successfully re-fracturing this interval afterwards are small. Remedial measure may need perforation of a nearby interval and starting a new fracture from there, using smaller proppant concentrations, higher pad volumes, higher viscosity fluid, better loss control additives, etc.).*

4. Finally, a small volume of liquid ('flush' or 'overflush') is pumped to displace the remaining slurry from the wellbore into the formation. The volume is less than the wellbore volume to avoid over-displacement of proppant resulting in a 'choked', i.e. partly closed fracture next to the wellbore.

5. The pumping is stopped and the fracture is left to stabilise: the fracture fluid remaining in the fracture leaks off, fracture pressure decreases and can no long hold the rock faces apart, and the fracture eventually closes on the proppant.

As mentioned, the fracturing fluid normally has high viscosity: hundreds of cP, to be able to transport proppant and decrease fluid loss. Such high viscosity fluid would have had immense difficulty to flow back and clean up the propped fracture (at least partly, see later the section on the retained fracture conductivity) so that it achieves high conductivity. This fluid viscosity is therefore designed to degrade after the treatment, to the viscosity value similar to that of water, by incorporation of a chemical breaker into the fracturing fluid formulation. This will allow some of this fluid to be produced back after the treatment, followed by the initiation of hydrocarbon production.

The surface and well set up required to achieve the above are schematically illustrated in Figure 4.

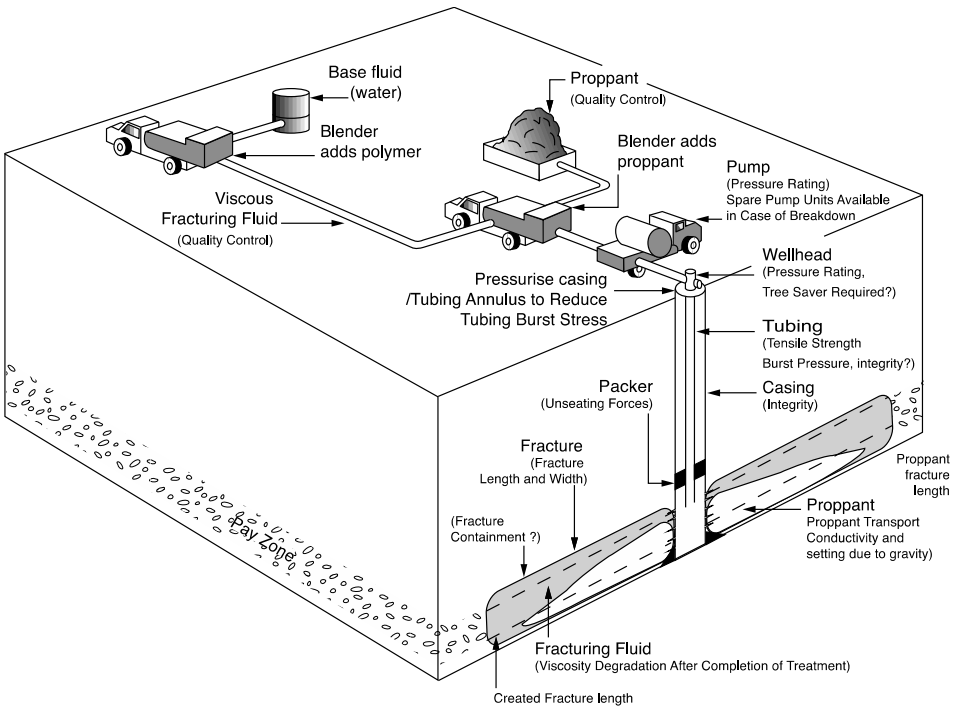


Figure 4 Practical issues during a propped hydraulic fracturing treatment

Figure 4 shows the (viscous) fracturing fluid being prepared from a polymer and base fluid (usually water – the cheapest). It is then combined in a blender with proppant (e.g. sand grains) used to keep (or prop) the fracture open once the treatment has been completed. Proper quality control measures are required for both the fluid and the proppant.

The proppant/fluid slurry is then passed to high-pressure pumps where the fluid pressure is increased to a sufficiently high value that a hydraulic fracture can be created in the pay zone. Hydraulic fracturing has to be done as a continuous process – spare pumps have to be IMMEDIATELY available if pump breakdowns are experienced. The wellhead must have a sufficiently high-pressure rating. This pressure rating of the wellhead can be temporarily increased by the insertion of a "tree saver" short tubing to protect the Xmas tree (though this saver has a lower diameter than the tree – hence adds some flow restriction), or temporary placement of a protective 'frac stack' equipment.

The production tubing will be subject to burst forces due to the high pressures required for fracturing. They can be reduced somewhat by pressurising the casing/tubing annulus. The casing has to be protected by a large diameter pressure relief valve in case the tubing fails and the casing is exposed to the high pumping pressure. The tubing will also contract due to the pumping of the cold fracturing fluids. This may lead to tensile failure (tubing parting) or the packer unseating. In practice, the design value for the tubing strength should be reduced appropriately to allow for any corrosion if the well has been on production for a number of years. *Field experience indicates that it is often impossible to mechanically carry out a hydraulic fracturing treatment in a well unless this was included in the original well design specifications.*

All in all, the issues to be evaluated during the fracture treatment design include:

- Whether the well is a good candidate for fracturing

- Transport of the proppant to the fracture tip
- Settling of proppant due to inadequate fracturing fluid viscosity
- Creation of the required proppant pack width and degradation of the fracturing fluid to minimise permeability damage to the proppant pack and formation and;
- Containment of the hydraulic fracture to the pay zone

These will all be discussed in the following sections.

4. HYDRAULIC FRACTURE TREATMENT CANDIDATE SELECTION GUIDELINES

Normally, hydraulic fracture stimulation is required for the economic development of low permeability reservoirs.

The hydraulically fractured well with the negative skin will have the greatest production rate.
Similar to the general stimulation candidate selection guidelines discussed in Chapter 8, propped hydraulic fracture well stimulation should only be considered when the:

- Well is connected to adequate **producible reserves;**
- **Reservoir pressure** is high enough to maintain flow when producing these reserves (or it is economically justifiable to install artificial lift);
- **Production system** can process the extra production.

These **minimum** criteria are equivalent to those used for matrix treatments and are summarised in Table 2 for conventional fracturing. Note however the reservoir permeability required is lower than for matrix acidizing. Modern, multi-stage unconventional and tight-reservoir fracturing technology further lowers the reservoir permeability criterion to nano-Darcies.

Propped hydraulic fracturing is also a comparatively complex technology requiring that:

- **Professional, experienced personnel** are available for treatment design, execution and supervision along with high quality pumping, mixing and blending equipment.

The ability to complete the treatment to the specified design requires numerous, on-site adjustments during the treatment itself. The first hydraulic fracturing treatments in a new area often experience early screen out resulting in premature stopping of the treatment i.e. the "learning curve" has to be climbed. The steepness of this "learning curve" can be increased by employing personnel who have gained experience in successful fracturing treatments in another area.

Parameter	Oil Reservoir	Gas Reservoir
Hydrocarbon Saturation	> 40%	> 50%
Water Cut	< 30%	< 200 bbls/MM scf**
Permeability †	1-50 mD *	0.01-10 mD
Reservoir Pressure	< 70% depleted	twice abandonment pressure
Gross Reservoir Height	> 10 m	> 10 m
Production System	20% spare capacity ø	

* Frac and Pacs may be applied to higher pereability formations
ø Lower value if several wells are manifolded together
† see also criteria for matrix treatments (Table 3 of Chapter 8 of this module)
** evaluate potential for well killing itself due to liquid loading in the tubing

Table 2 Minimum hydraulic fracturing candidate well selection screening criteria

5. CREATION OF A PROPPED HYDRAULIC FRACTURE

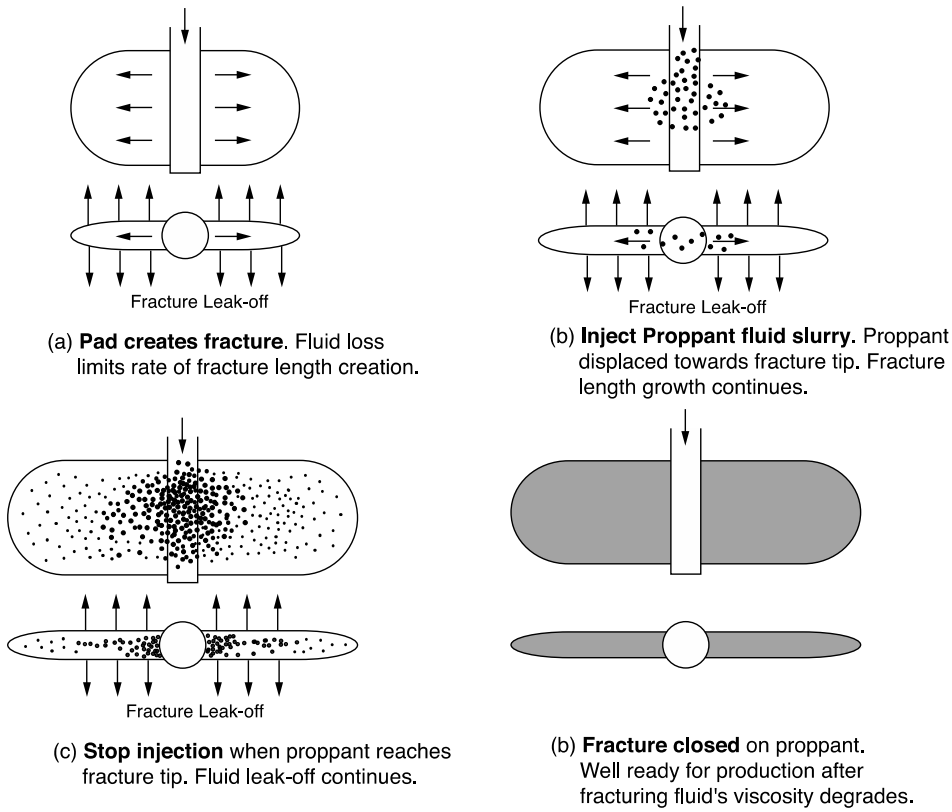


Figure 5 Creation of a propped hydraulic facture

Figure 5 summarises the main stages in the process involved in creation of a propped hydraulic fracture. A few more details of this process are provided below:

- As mentioned, an initial fracture of appropriate length and width is largely created by pumping a volume of fracture fluid called the pad. The most common fracturing fluids are water based, cross-

linked, polymer solutions (or gels) which exhibit highly non-Newtonian rheological properties together with appropriate fluid loss properties. (This is often preceded by a sacrificial pre-pad (a low viscosity fluid which acts as a part of the fluid loss from the fracture at a reduced cost).) Typically, about 40 – 80% of the pad total fluid volume pumped leaks off to the formation while only 20 – 60% creates useful fracture volume, able to accept the proppant slurry.

- Proppant particles, typically the well-sorted sand from sand mines, or sometimes artificial ceramic particles, are added at low concentration to the fracturing fluid once the fracture width is sufficient to admit the proppant without causing a screen out and the created fracture is nearing its design length.

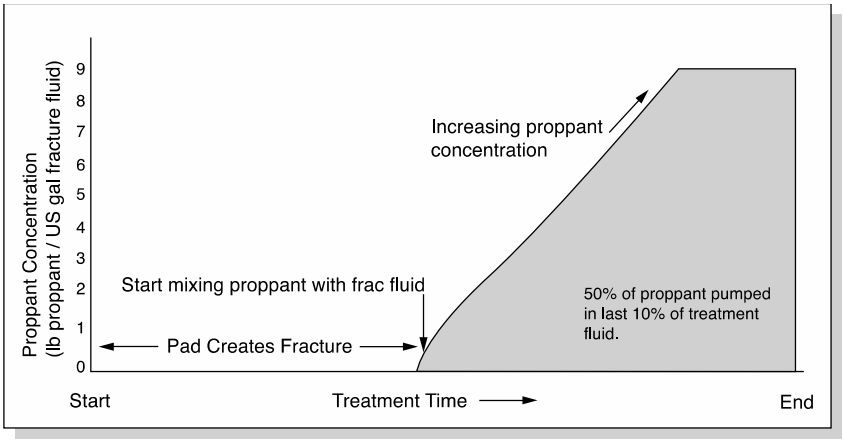


Figure 6 ***(a)*** Hydraulic fracturing proppant concentration increase during a hydraulic fracturing treatment

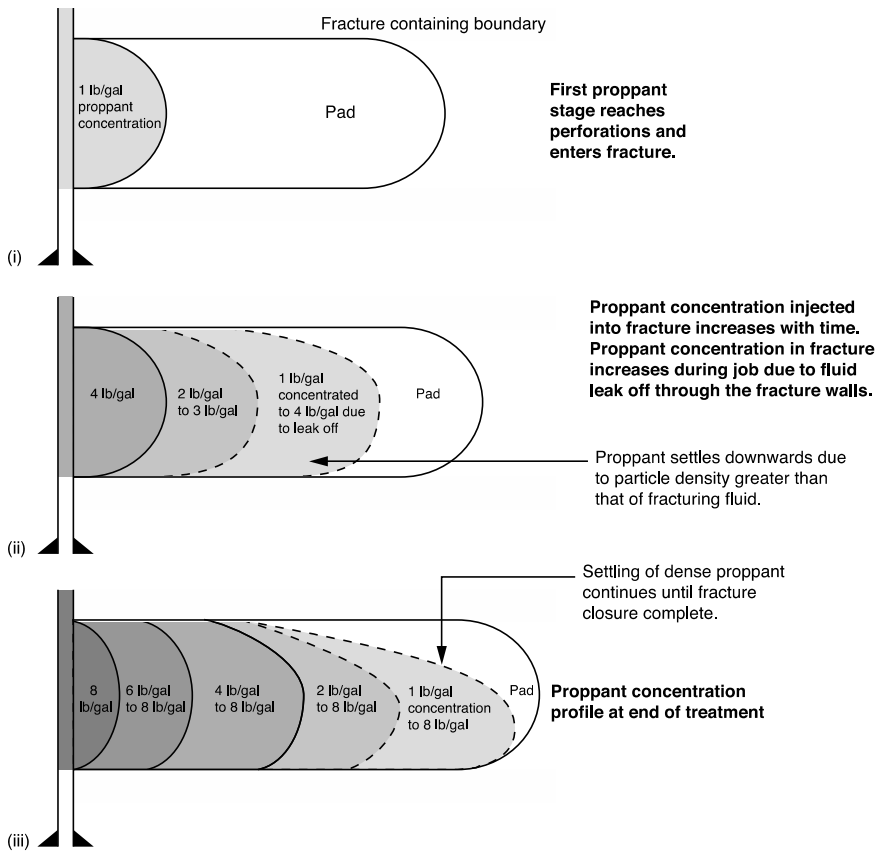


Figure 6 ***(b)*** Proppant profile development during a hydraulic fracture treatment.

The concentration of proppant is increased towards the end of the job with proppant concentrations as high as 40% vol being pumped (Figure 6a). This ensures that a more uniform, final proppant concentration in the fracture is achieved. This occurs because the low proppant concentration in the slurry pumped initially will become more concentrated as it is displaced towards the fracture tip as the fracturing fluid leaks off into the formation. "Settling" of the denser proppant will also occur due to the influence of gravity. This process will continue until fracture closure is complete. These processes are illustrated in Figure 6 (b).

The proppant slurry in the wellbore is displaced to the perforations and fluid injection halted. This normally occurs at about the same time as the first proppant reaches the fracture tip. There will be minimal stimulation from the fracturing treatment if the final proppant slurry volumes are overdisplaced away from the wellbore i.e. the well loses (direct) communication with the ('choked') hydraulic fracture. However, excessive under displacement of the slurry will leave large amounts of proppant in the wellbore at the end of the treatment. This would then have to be removed by a special cleanout trip made with a coiled tubing or workover unit prior to returning the well to production.

Leak-off continues and the fracture closes on the proppant. Viscosity degradation from the action of the chemical breaker added to the fracturing fluid aids in the back production of the degraded fracturing fluid followed by hydrocarbon production.

A complex computer program is required for treatment design since, in addition to the complexities of fracture shape prediction described earlier, it must also optimise the transport of the proppant within the fracture.

6. A BRIEF REVIEW OF ROCK MECHANICAL ISSUES RELATED TO HYDRAULIC FRACTURING

6.1 In-situ Stress

Generally, at any given depth there are three principal earth stresses oriented at right angles to one another (Figure 7). Below about 500m, in a relaxed tectonic environment, the vertical stress (σ_v) is normally the greatest (this situation is called 'normal fault stress regime'). It can be quantified by integrating the density log over TVD from the point of measurement to the surface. An average value of 1.0 to 1.1 psi/ft is measured for wells at reasonable depth – though lower values are encountered in shallow, particularly offshore environments subject to rapid deposition.

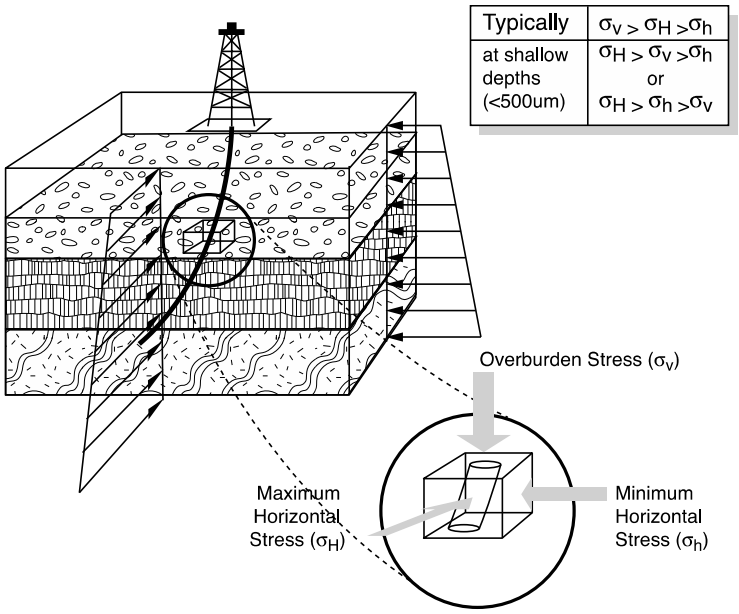


Figure 7 In-situ stresses in the subsurface

The other two stresses - the maximum (σ_H) and minimum (σ_h) horizontal stresses are oriented at right angles to each other and at right angles to the vertical stress. (The maximum horizontal stress σ_H is also referred to as the intermediate stress.)

In tectonically active areas e.g. in the foothills of mountain chains where mountain building is occurring; the maximum in-situ stress may no longer be vertical but is tilted. The orientation between the three in-situ stresses remains the same - hence the minimum and intermediate stresses are also no longer horizontal.

Propagation of a Hydraulic Fracture requires the actual splitting apart of the fabric of the formation. The split will propagate in the direction of least resistance i.e. will occur most easily in the direction perpendicular to the minimum in-situ stress. Thus, in tectonically relaxed environments, we can assume that a hydraulic fracture will have a vertical orientation and will grow (propagate) in the direction of the intermediate (or maximum horizontal) in-situ stress i.e. at right angles to the minimum in-situ stress, while splitting apart in the direction of this minimum stress (Figure 8):

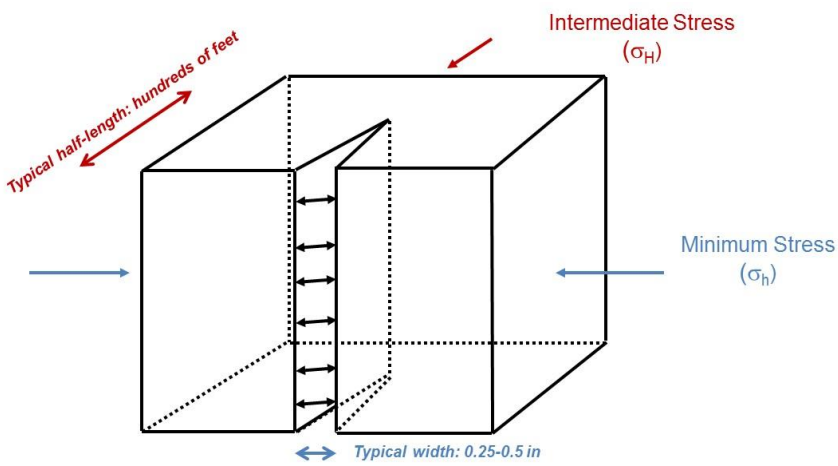


Figure 8: Fracture orientation under the normal fault stress regime

As discussed earlier, the vertical stress (σ_v) can be measured, or assumed, with reasonable accuracy. The important rock property for predicting the other two stresses from the vertical stress is called Poisson's Ratio (***v***), the ratio between Lateral Strain (ε_y) and the Longitudinal Strain (ε_x)

i.e.
$$v = \frac{-\varepsilon_y}{\varepsilon_x} = \frac{-\text{Lateral Strain}}{\text{Longitudinal Strain}}$$

{the negative sign is included because (convention) states expansion should be treated as negative and we wish Poisson's Ratio to be a positive number}. Typical Poisson's ratio for consolidated sandstones is about 0.25.

Another property important in fracturing is the Young's (a.k.a. elasticity) modulus *E* defined as the ratio of the longitudinal stress to the longitudinal strain.
Figure 9 explains how subjecting a rock sample to a vertical (the overburden) stress results in it shortening in the vertical direction and expansion in the horizontal direction. A similar effect occurs in a reservoir rock deposited in a sedimentary basin. As mentioned, the magnitude of the vertical stress at any depth is related to the weight of the overlying rock mass.

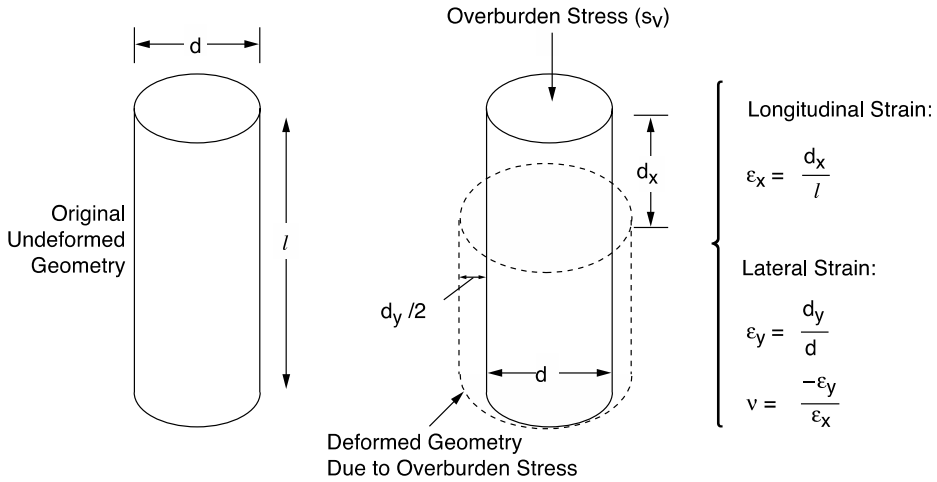


Figure 9 Measurement of Rock properties: Poisson's Ratio (v)

In the simplest case the horizontal stress depends only on the elastic behaviour of the rock. The overburden load can then be related to the horizontal stresses via the above Poisson's effect together with assumptions about the lateral boundary conditions. In a tectonically relaxed area, the two horizontal stress components will have the same value within a specific lithology:

$$\sigma_h = \sigma_H = \left(\frac{v}{1-v}\right)\sigma_v \approx \frac{1}{3}\sigma_v \quad \text{if } v = 0.25$$

Variations in lithology, and hence variations in Poisson's Ratio, will lead to abrupt changes in horizontal stresses with depth. For instance, shale layers will have a higher Poisson's ratio, and hence a higher σ_h, than sandstones.

The above is a simplified picture of the behaviour of rock formations; but it does allow a first estimate of the potential horizontal stress changes between layers. Figure 10 illustrates the resulting stresses from deposition of a formation with constant lithology. Here tectonic forces resulting from movement of the Earth's crust have induced an additional stress component (σ_{tec}) to σ_H so that the two horizontal components are no longer equal.

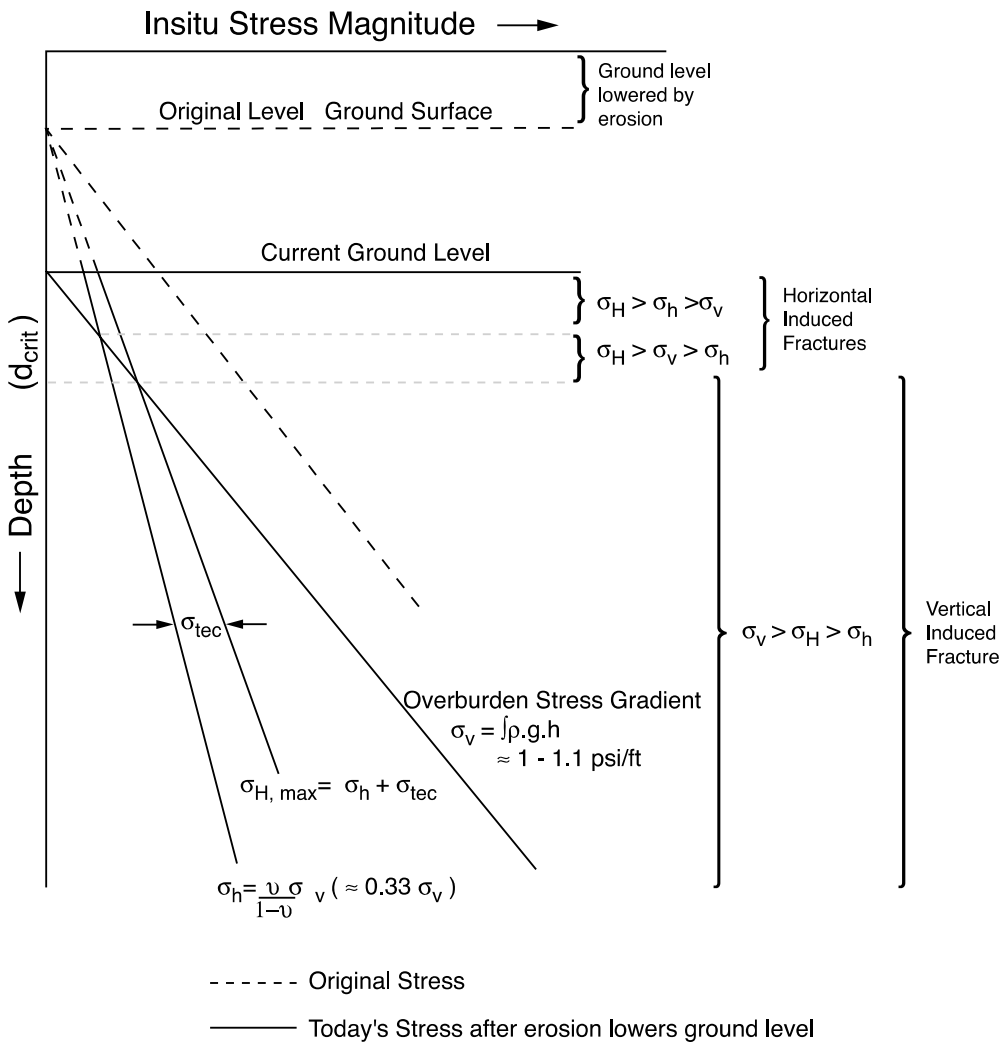


Figure 10 Magnitude of in-situ stress

Surface elevations change over geologic time. Figure 10 shows how surface erosion has changed the vertical stress profile while the horizontal stresses have remained "locked-in" due to, for example, inelastic rock deformation. This explains why the vertical stress is normally not the largest one at shallow depths. Other geological processes, such as burial and uplift, also lead to similar anomalous stress patterns.

As mentioned, the presence of a minimum horizontal stress implies that there will be a preferred direction of fracture propagation. The fracture will grow in the "easiest" direction (which requires the least amount of energy) i.e. as a vertical fracture perpendicular to the minimum horizontal stress below the critical depth (d_{crit} in Figure 10) and as a horizontal fracture at shallower depths.

6.1.1 EFFECTIVE STRESSES

The pore fluids present within the rock matrix will support a proportion of the total applied stress *(a similar effect makes it easier to lift objects in water than in air)* (Figure 11). This means that effective stress (σ') carried by the rock matrix grains is smaller than the total stress by the value proportional to the pore pressure P_p. This can be quantified as:

$$\sigma' = \sigma - \alpha P_p$$

where σ is the total stress, P is the pore pressure and σ ' is the effective stress (for this reason the effective stress acting on the rock and/or proppant increases as the reservoir is depleted and its pressure declines, potentially resulting in rock/proppant failure and sand/fines production). The inter-grain cementation does not allow the pore pressure to completely counteract the applied load, hence the correction factor: the Biot's poro-elastic constant α (it typically varies between 0.7 and 1 for petroleum reservoirs).

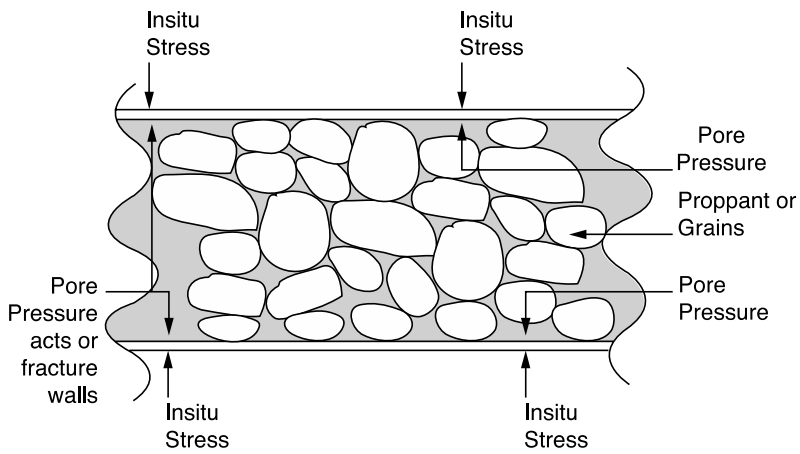


Figure 11 Effective stress acting on a propped fracture.

The effective horizontal stress in the reservoir (where the average pore pressure obviously equals the average reservoir pressure P_R) thus becomes (assuming no tectonic additive in the minimum principal stress direction):

$$\sigma_h^{'} = \frac{\nu}{1-\nu}(\sigma_v - \alpha \mathrm{P}_R)$$

Finally, in order to propagate a fracture, the fracturing fluid needs to at least overcome the minimum effective stress as well as act (get injected) against the reservoir pressure. This minimum combined pressure against which the fracture propagation must act against, or in other words the pressure at which the fracture closes (a.k.a. 'fracture closure pressure FCP' or 'closure pressure' or 'closure stress') is given as:

$$\sigma_h = \textit{fracture closure pressure} = \frac{\nu}{1-\nu}(\sigma_v - \alpha \mathrm{P}_R) + \alpha \mathrm{P}_R$$

Note that this pressure decreases with the decrease in the pore pressure.

One important conclusion from these equations is that the values of the stresses which control fracture propagation can change as the reservoir pressure depletes during the life of a petroleum reservoir. Hence the stress profile measured early in a field's lifetime may become invalid as the field matures. E.g. a hydraulic fracture created later in the life of a field will tend to be more confined to the pay zone than a similar treatment carried out early in field life. This occurs because the pay zone reservoir pressure will have decreased due to oil or gas production, while the pressure and hence the in-situ stress in the bounding shale will be unchanged: this reservoir vs. shale stress contrast can be used to control the fracture height migration. Therefore, the net pressure (defined as the wellbore or fracture pressure during fracturing minus the fracture closure pressure: $p_{net} = p_w - \sigma_h$) may be kept sufficiently high to propagate the fracture in the pay zone, yet not high enough to propagate it in the surrounding shale layers.

(It is less economically efficient to create a fracture higher than the pay zone, let alone such a fracture may also reach the water (or gas if any) layers beyond the shale layers (i.e. 'frac into water') and flood the well with water during production.)

- *Feel free to attempt Tutorial 2*

6.1.2 FRACTURE INITIATION AND WELL PERFORATION PROGRAMME

As discussed, the induced hydraulic fracture propagates at right angles to the minimum in-situ stress. From a conceptual point of view, it can be seen that the:

Fracture Propagation Pressure (FPP) ≈
minimum rock in-situ stress (or closure stress) + fracture toughness

since the propagating fracture has to overcome the forces that are preventing further splitting of the rock at the tip i.e. the minimum rock in-situ stress and its 'fracture toughness' (the cohesion between the formation grains which needs to be overcome to allow the fracture to propagate, also known as the critical Stress Intensity Factor).
Often there are also additional fluid pressure losses around the wellbore and in the fracture that add to the FPP.

The Fracture Initiation Pressure (FIP), or break down pressure, i.e. the pressure needed to start the fracture propagating from the perforation or openhole wellbore, will normally be greater than the FPP. This is because fracture initiation requires additional energy to overcome the tensile stresses present around the borehole plus any extra pressure required to overcome the fact that the perforation is not oriented in the preferred direction for fracture propagation (where the fracture is created in a perforated well). *(Such wellbore tensile stresses may be negligible if a previously created, or a natural fracture is reopened).* Inefficient perforating can increase the FIP. Figure 12 illustrates the worst-case scenario when inline (0^0 phasing) perforations happen to be aligned normal to the direction of fracture propagation.

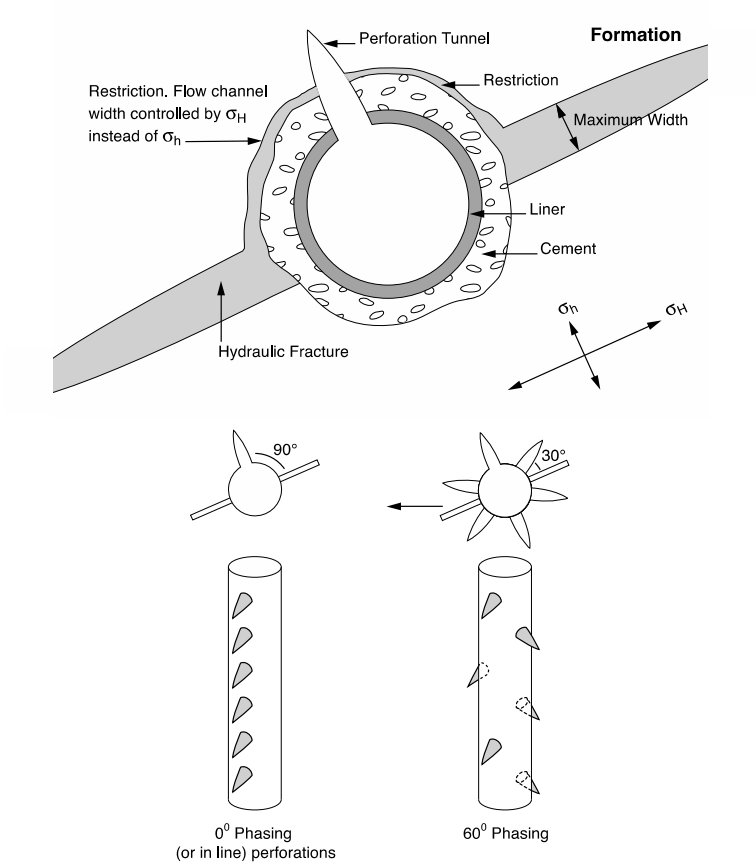


Figure 12 Hydraulic fractures and perforation phasing

Figure 12 shows how the fracture has to initiate from the perforation and then travel around the well until it achieves the preferred orientation, after which it will propagate away from the well. The width of the induced fracture is related to the difference between the fluid pressure in the fracture and the in-situ stress. The fracture will be much narrower at the point of initiation since the maximum rather than the minimum, horizontal stress is acting on the fracture. This area of restricted width may not be wide enough to allow the passage of proppant grains during the later stages of the fracturing treatment. Such wellbore friction (across the perforations) and tortuosity effects can add significant pressure loss, especially when the proppant slurry is pumped, resulting in premature screen out at the wellbore. (The relative importance of this restriction will also depend on the difference between the two horizontal stresses).

60° or 45° phasing perforations have a much better chance that at least some of the perforations to be at sharp angles with the fracture propagation direction. Field experience (backed up by simple geometric considerations) indicates that the FIP can be minimised by perforating the well with 60^0 (or lower) phasing - the maximum difference between the perforation and induced fracture orientation will now be reduced to 30^0 (Figure 12 bottom right).

6.2 Data Gathering

Prior to carrying out the minimum hydraulic fracturing treatment it is advisable to carry out a smaller, data-gathering fracture treatment, to measure the formation and fluid properties. This is very important to estimate the stresses and the fracturing fluid's leak off coefficient in order to properly design and execute the subsequent fracture job.

Depending on the pad volumes pumped, this is called a microfrac (< 5 m^3) or a mini frac (< 50 m^3). (Such tests are a.k.a. 'mini fall off', 'diagnostic fracture injection test' (DFIT), 'diagnostic injection', 'datafrac', etc.) Figure 13 illustrates the set up for such a treatment and some of the important pressure reference points. The fluid is pumped at a constant rate for the required time and the treatment pressure measured. Bottom Hole Pressure measurements are preferred being much more accurate than surface measurements, otherwise the hydrostatic head and friction pressure drop components have to be estimated.

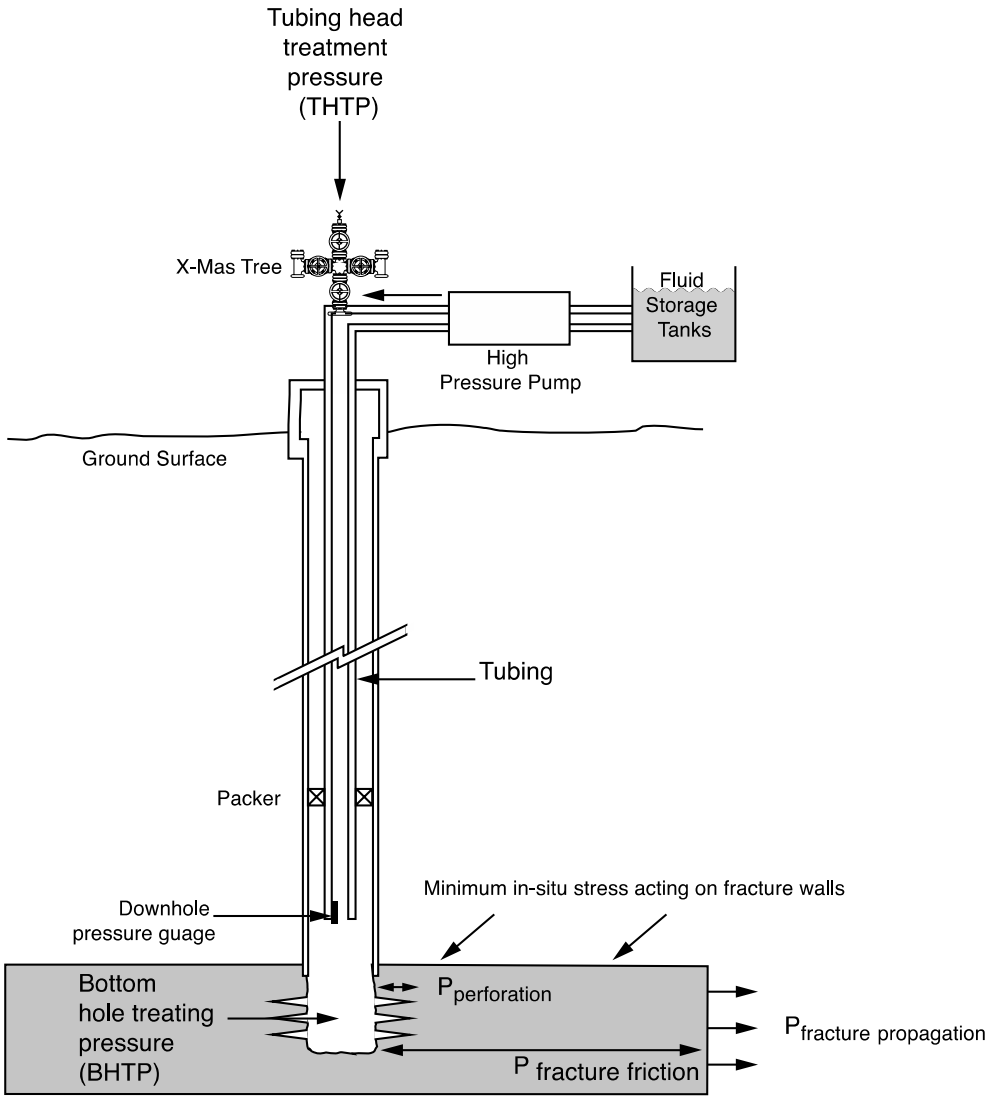


Figure 13 Arrangement for a mini or microfrac treatment

N.B. Proppant is not used during these treatments. Also, only a short interval is often perforated.

An example pressure/time recording is shown in Figure 14 and is described as follows:

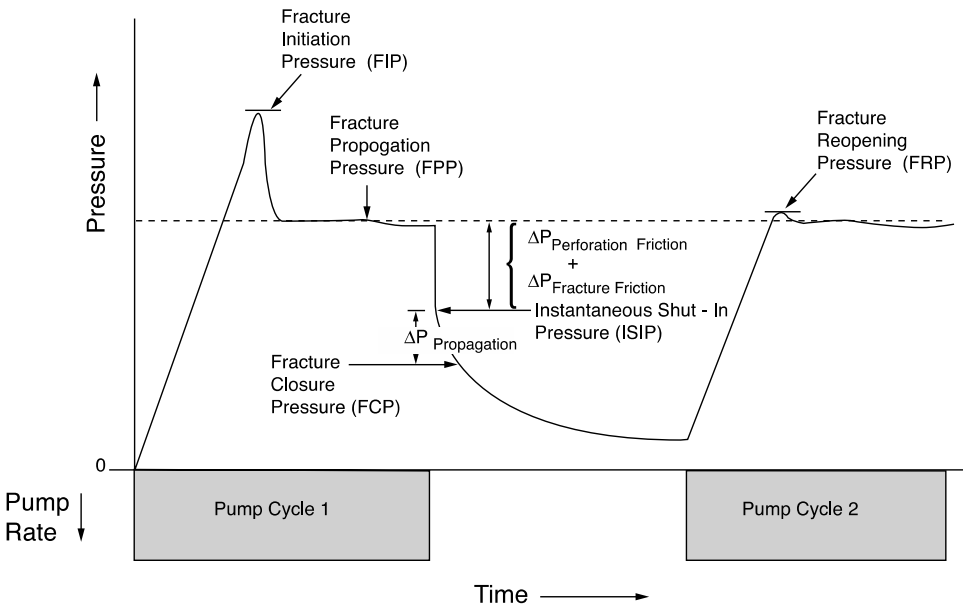


Figure 14 Bottom hole pressure recorded during a micro or mini frac *(Note that 'zero' on the vertical scale refers to the pump rate axis, not the pressure axis)*

- The bottom hole pressure begins to rise as soon as the pumps are started. This increase continues until the Fracture Initiation Pressure (FIP) is reached, after which it drops rapidly to the Fracture Propagation Pressure (FPP).

- The pumps are stopped when the desired fluid volume has been pumped, and fracture propagation ceases. This pressure drops rapidly to the Instantaneous Shut-In Pressure (ISIP):

$$ISIP = FPP - \Delta P_{perforations} - \Delta P_{fracture\ friction}$$

Where $\Delta P_{perforation\ friction}$ = Pressure drop across the perforations and
$\Delta P_{fracture\ friction}$ = Frictional pressure drop from the perforations to the tip of the fracture

(It may be difficult to separate these two pressure drops. Additional tests like rate step-down test or step-rate test where the rate is respectively gradually decreased at the end or increased at the beginning of the fracturing may be used to estimate the perforations and tortuosity -caused pressure loss component).

- The fracture is still open at the ISIP. Leak off continues at a high rate from the open fracture. The pressure drops until the Fracture Closure Pressure (FCP), equal to the minimum in-situ stress (σ_h), is reached.

$$ISIP = FCP + \Delta P_{fracture\ propagation}$$

Where $\Delta P_{fracture\ propagation}$ is the pressure required to overcome the fracture toughness

The FCP is recognised as a change in slope in the pressure decay curve (the decay rate slows down). Fluid is leaking off into the formation from the whole fracture surface when the fracture is open. The fluid loss rate decreases to a low value after the fracture closes, since the area available for fluid loss (perforations rather than an open fracture) is so much smaller. The subsequent, slower decline rate once the fracture is closed is merely due the reservoir pressure stabilisation.

N.B. If observed long enough, the pressure will eventually equalise at the reservoir pressure. This may take a long time in low-permeability reservoirs.

- Reopening of the fracture during a second pump cycle will normally occur at a lower value than the FIP – often the pressure "hump" does not occur and the FPP is observed immediately.

Table 3 records example values for the various parameters discussed above for a mini/microfrac treatment in a well perforated at 6,000 ft. These values are specific to the well to be treated. They are required when designing the full-scale, subsequent hydraulic fracturing treatment. In addition, one can derive further, valuable information.

Pressure values in	
Tubing	**psi**
Tubing Head Treating Pressure	6400
$P_{friction}$	-6200
$P_{hydrostatic\ head}$	+4500
Bottom Hole Treating Pressure	4700
Fracture	**psi**
$P_{perforation}$	-100
$P_{friction}$	-100
$P_{propagation}$	-300
Minimum in-situ stres = 4200	

Table 3 Typical pressure values for a mini/micro frac treatment at 6,000ft

- The longer the fracture takes to close after the cessation of pumping, the lower the leak off coefficient and the greater the fracture volume created (i.e. the fracture fluid efficiency is higher). The plots of the net pressure vs. time during this pressure decline period can be used to estimate the leak off coefficient: one of the most important parameters controlling the fracture geometry and the fracturing process. It is also one of the few parameters (along e.g. with the fluid viscosity) the engineer has some control of. The plots of the net pressure w.r.t. time on log-log scale, or w.r.t. the square root of time are used. G(t) function (a special formula dependent on the total elapsed, closure, and pumping times and the type of leak-off) can also be plotted vs. time in such analysis.

A volume balance can be performed to quantify this fluid loss coefficient which can then be used as input to fracture treatment design programs.

Similarly, the bottomhole pressure can be measured (or estimated from the surface pressure) and interpreted in real time during proper fracturing. This information is very insightful and can be used to make the job adjustments on the fly, as well as monitor the progress and diagnose the fracturing efficiency.

For instance, by plotting the net pressure vs. time (a.k.a. 'Nolte-Smith' method) on the log-log plot it is possible to monitor the fracture propagation model (e.g. it is normal when the slope is 1/5, or screened out when the slope is 1, or may show fracture height growth as is explained later, etc.).

Core and log tests

Apart from the minitests, some properties can be estimated from the core and openhole log measurements. For instance, the rock mechanical properties: Young's modulus (E_s, in psi) and Poisson's ratio (ν) can be estimated from the shear (Δt_s) and the compressional (Δt_c) wave propagation times (or velocities reversely proportional to these times) as measured by the long spaced sonic log:

$$E_s = \left(\frac{\rho_b}{\Delta t_s^2}\right)\left(\frac{3\ \Delta t_s^2 - 4\ \Delta t_c^2}{\Delta t_s^2 - \Delta t_c^2}\right) 1.35 * 10^7$$

Where ρ_b is the rock density in g/cm^3 and the wave velocities are measured in ft/µs.

$$\nu = \frac{1}{2}\left(\frac{\Delta t_s^2 - 2\ \Delta t_c^2}{\Delta t_s^2 - \Delta t_c^2}\right)$$

Note that the acoustic-derived, dynamic Young's modulus (E_s) can significantly differ from the static one important in fracturing. Ideally the dynamic Young's modulus should be corrected using available static modulus values obtained from the core tests.

Typical measurements for various rock types are given in Table 4. This shows that non-reservoir rocks tend to have a higher Poisson's ratio. Hence, they can be expected to have a higher in-situ stress than the reservoir aiding fracturing containment within the reservoir, as was mentioned earlier.

Lithology	$\Delta t_s/\Delta t_c$	ν
Sandstone/water	1.78	.27
Sandstone/gas	1.6	.18
Dolomite	1.8	.28
Limestone	1.9	.31
Wet Siltstone	1.73	.25
Shale	2.08	.35

Table 4 Poisson's Ratio (ν) calculated from the shear ($1/\Delta t_s$) and compressional ($1/\Delta t_c$) wave velocities measured by the long spaced sonic logging tool.

The orientation of the principal stress can be measured using tiltmeters (measuring tiny changes in the earth surface around the well due to fracturing) or multi-finger calipers (the wellbore wall often takes oval shape to accommodate the horizontal stresses, more 'squashed' in the direction of the intermediate stress).

Post-fracturing production logging

- The fracture height can be measured at the wellbore after fracturing the well. For instance, a temperature log is run as part of the production log assembly across the perforated interval before

and immediately after completion of the minifrac treatment. This production log, which incorporates a high-resolution thermometer, will record a (cool/lower temperature) zone across the created fracture due to the injection of the relatively cool fracturing fluid. Figure 15 is a schematic example of such temperature log, the fracture being observed to have grown upwards from the perforated interval.

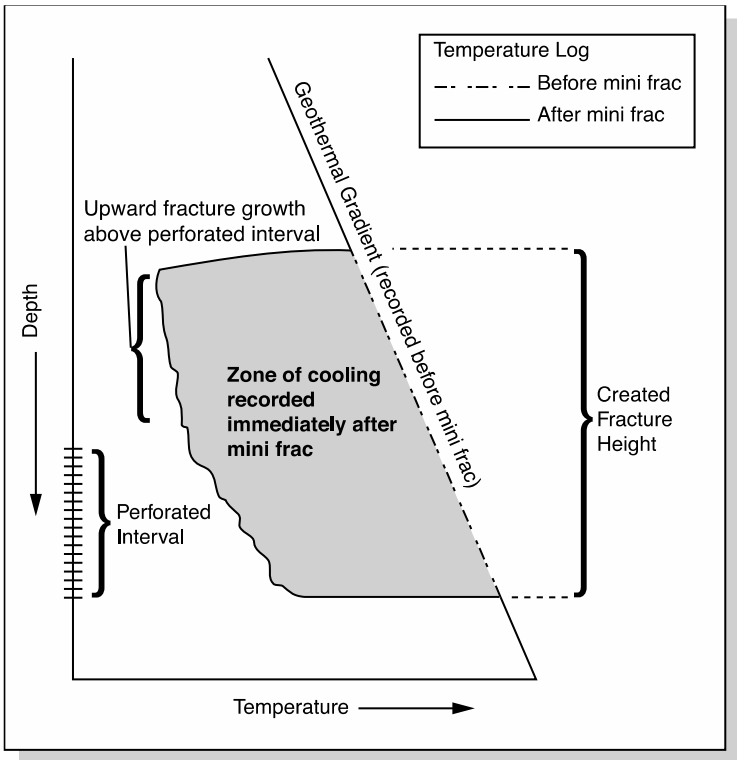


Figure 15 Fracture height measurement using a temperature log

Alternatively, this can be achieved by adding some radioactive marker coating to the proppant that can help locate the fracture position with a GR log, or by detecting production fluid flow in the fracture using noise log, or by using microimaging logs that can detect the fracture entry in openhole wells.

Far-field measurements (e.g. geophones in the nearby wells detecting the tiny microsesimic events as the rock breaks along the fracture propagation front) can also be sometimes used to triangulate the fracture's 3D structure.

6.3 Fracture Size

Greater volumes of fracturing fluid will create larger fractures – with higher treatment costs but also potentially more productive. However, uncontrolled, vertical growth of fractures is not desirable from a production point of view e.g. when the target oil zone is overlain by gas and/or with water underneath, or is closely surrounded by water and/or gas layers. Figure 16 shows how the maximum fracture size is limited for this situation. It assumes that:

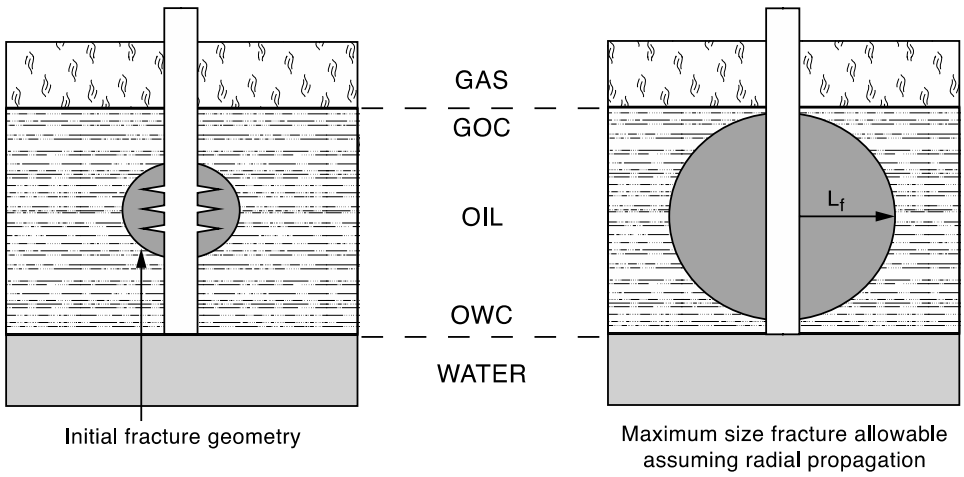


Figure 16 Fracture size limited by geometry and fluid contacts

- The fracture is initiated from perforations at the mid point of the oil zone.

- The fracture propagates radially (in practice, this implies that the formation is homogenous with the stress gradient equal to the hydrostatic head of the fracturing fluid).

The resulting maximum allowable fracture half length (L_f) is slightly less than half the height of the oil column.

6.3.1 FRACTURE CONTAINMENT

The hydraulic fracture should thus be designed so that it does not contact unwanted fluids within a single formation layer. It must also be considered whether the hydraulic fracture is contained within the pay zone i.e. whether upward and/or downward fracture growth is retarded by changes in the formation property contrast between the two layers. Important formation properties include:

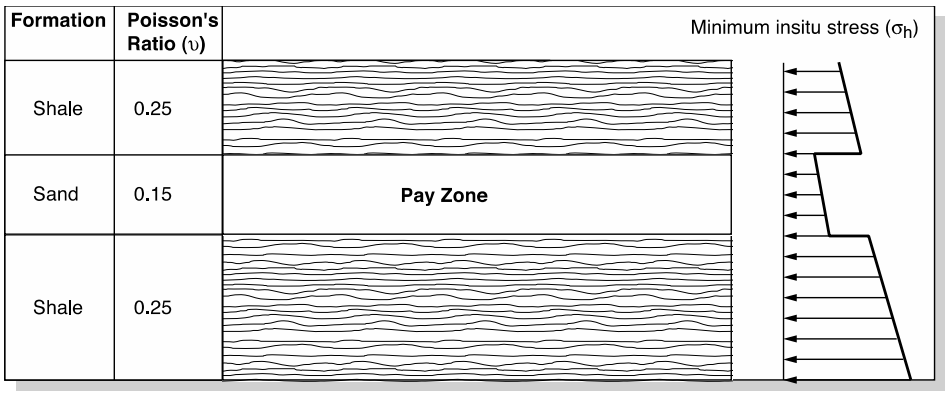


Figure 17 In-situ stress contrasts

- (Minimum) in-situ stress: permeable formations e.g. sand typically have a lower Poisson's Ratio compared to the bounding shale layers. The resulting lower in-situ stress will aid hydraulic fracture containment (Figure 17).

- Fracture toughness: increased values of the fracture toughness imply that it is more difficult for the fracture to propagate in that zone.

- Leak off: high fluid loss rates will retard fracture propagation through the zone.

3-D fracture propagation models are available to predict the simultaneous lateral and vertical growth of the hydraulic fracture. These complex numerical codes have been used to generate the following examples which illustrate some of the important factors concerning fracture containment.

6.3.2 HIGH IN-SITU STRESS CONTRASTS AND FRACTURE SHAPES

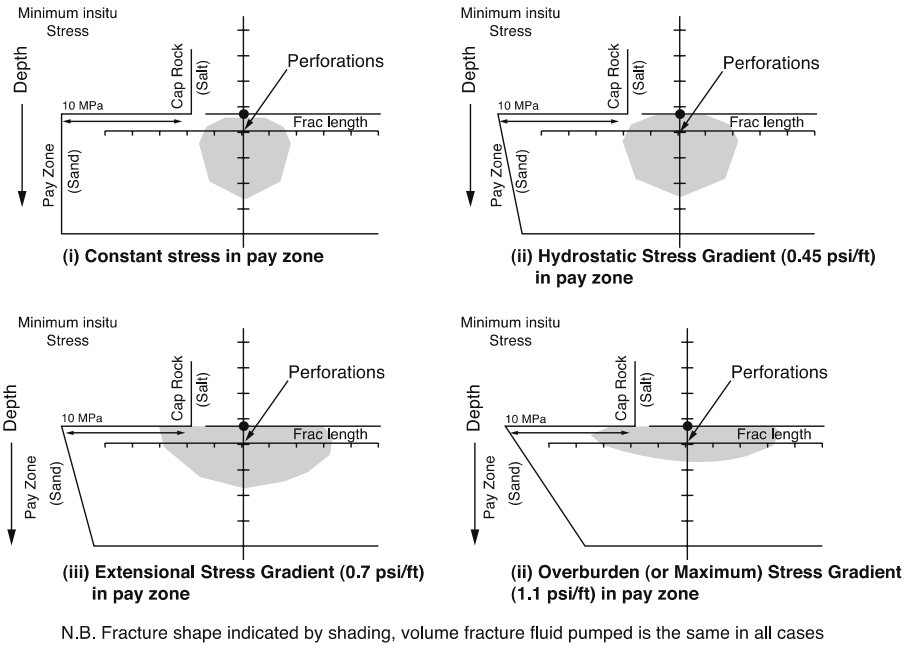


Figure 18 Effect of stress gradient on a fracture shape and containment

Figure 18 shows a case where a massive, homogeneous, gas bearing sandstone is overlain by a (sodium chloride) salt zone (the cap rock). The well is perforated near the top of the pay zone. Due to the plastic nature of salt:

$$\sigma_h = \sigma_H = \sigma_V$$

There is thus a very large in-situ stress contrast (estimated as 10 MPa) at the salt/sandstone boundary resulting in upward fracture growth being immediately halted. Due to the homogeneous nature of the sandstone, it is expected that there is a constant stress gradient. The effect on fracture shape and containment of differing values of the stress gradient is illustrated in Figure 18.

- **Constant stress (or zero stress gradient):** the fracture grows downwards due to the density of the fracturing fluid giving rise to an increased pressure at the bottom surface of the fracture compared to the top surface.

- **Hydrostatic stress gradient** (0.45 psi/ft)**:** the stress gradient in the formation is now the same as that of the fracturing fluid – resulting in radial propagation of the fracture, apart from the top surface where upward growth is stopped due to the large (10 MPa) stress contrast at the salt/sandstone boundary.

- **Extensional stress gradient** (0.7 psi/ft) is commonly found in relaxed tectonic environments. A longer fracture results since the fracture downward growth becoming limited due to the minimum in-situ stress increasing at a greater rate (0.7 psi/ft) than the hydrostatic head of the fracturing fluid (0.45 psi/ft).

- **Overburden (or maximum) stress gradient** (1.1 psi/ft). This scenario yields the longest fracture with the least downward growth. In fact, the fracture is trying to grow upwards, the reverse of the first scenario. This upwards growth constrained by the high stress contrast of the salt/sand boundary.

6.3.3 FRACTURE GROWTH INTO BOUNDARIES

Whether a pay zone boundary is capable of containing a fracture will depend on the magnitude of the fracture containment mechanism; e.g. the minimum in-situ stress contrast and the thickness of the boundary. Figure 19 illustrates fracture containment for three different values of the stress contrast. Initially the fracture propagates radially in the pay zone until the boundary layer is reached; after which it becomes more elongated – with greater stress contrasts giving rise to the more elongated shapes. N.B. The consecutive lines growing from the left-hand side refer to the fracture shape at increasing times/volume of hydraulic fracturing fluid pumped.

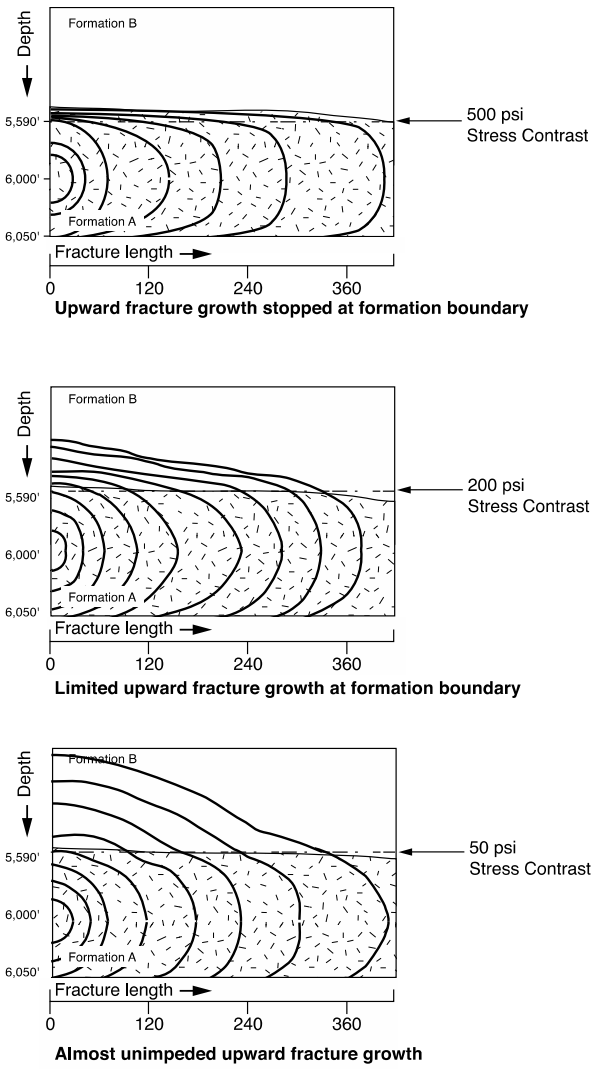


Figure 19 Vertical growth of fracture for various stress contrasts

Figure 20 schematically illustrates what occurs when fracture containment is no longer effective due to the height of the upper barrier and the available in-situ stress contrast being insufficient to prevent the fracture breaking through into a shallower (water bearing) zone.

- The fracture is initiated at the centre of the pay zone (time ***1***) and initially grows radially (time **2** and **3**) since a hydrostatic stress gradient is present. This results in the FPP decreasing as the fracture becomes longer.

- The stress contrast at the upper and lower boundary cause upward and downward fracture growth to be retarded. Upward fracture growth is somewhat easier as the stress contrast in this direction is lower. The effect of this partial fracture containment is an increase in the FPP (times **4, 5** and **6**).

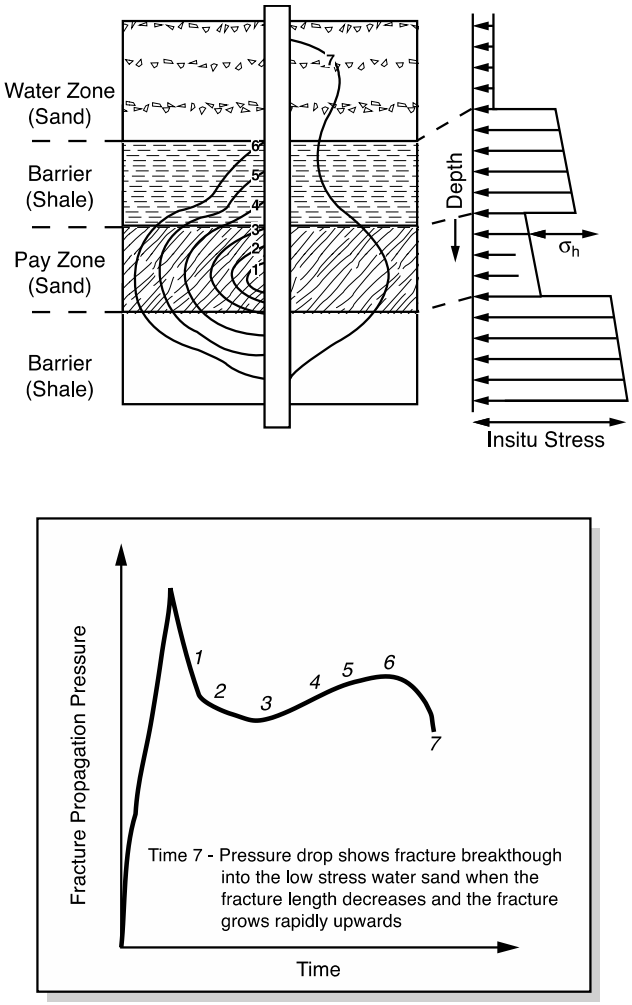


Figure 20 Fracture containment no longer achieved after time 6

- At time ***7*** the upward fracture growth allows the fracture to break through into the upper water bearing zone. Since this has a very low, constant fracture gradient, the fracture will grow rapidly upwards, resulting in a drop in the FPP. Note that the fracture length in the payzone has actually decreased due to the fracture's rapid expansion into the upper, water sand. Real time measurement of the FPP thus allows monitoring of fracture containment.

6.3.4 FRACTURE AZIMUTH AND WELL DEVIATION AND ORIENTATION

Earlier it was discussed how the induced hydraulic fracture would orientate itself at right angles to the direction of the minimum in-situ stress. This discussion implicitly assumed that the well was vertical. A more complicated situation arises when the well is deviated from the vertical – since the fracture and well azimuth are unlikely to be orientated in the same direction.

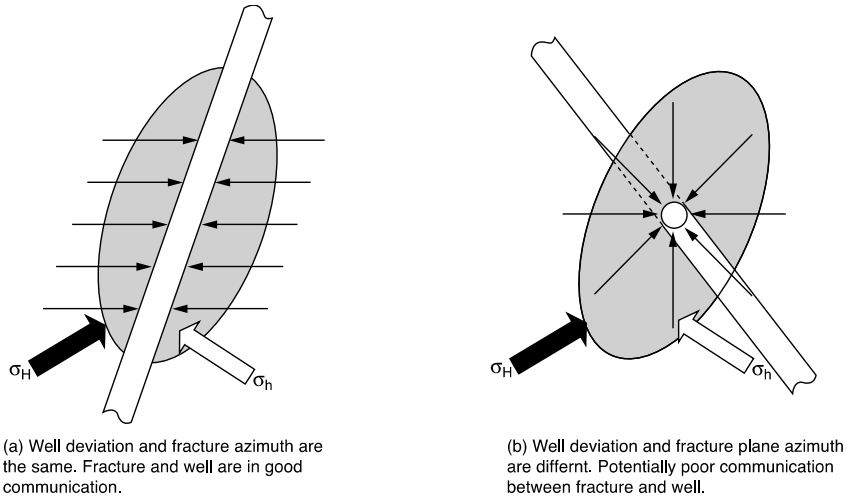


Figure 21 Hydraulic fracturing of deviated wells

- Figure 21a illustrates the case when the well was deviated in the plane of the fracture. Good fracture/well communication results once the well has been efficiently perforated {Section 6.1.2}.

- Figure 21b shows how the fracture is only in contact with short length of the well when the fracture and well azimuth are not the same. This can (potentially) lead to poor fracture/well communications and reduced well productivity.

The propped, hydraulic fracturing of deviated wells can require special measures, especially when the two in-situ stresses have very different magnitudes. The drilling of S shaped wells which are vertical across the pay zone is one option that avoids the problem discussed here, but does increase the drilling cost.

In unconventional, shale gas wells (discussed later) where the fracture planes are normal to the wellbore (drilled along the minimum stress direction), typically the 60° phasing, 3/8 in. perforation ensures adequate wellbore connection with the fractures.

6.4 Modelling the Shape of the Induced Fracture

Several (commercial) programmes are available to predict the shape (height, length and width) of the induced hydraulic fracture. They normally fall into one of three classes:

- **2D:** these models use two dimensional, analytical equations where the fracture height is required as input.

This class is used extensively in engineering programs, requiring a reduced data set as well as limited computing requirements. The analytical solutions are also insightful outlining the importance of various parameters affecting the fracture initiation, propagation and shape.

- **P3D:** or pseudo three dimensional programs. These programs combine analytical and numerical routines that can predict the fracture height and width somewhat independently.

This class is used by fracturing specialists and has moderate computing requirements. They can be used to design/forecast a fracture shape and a frac job, as well as to interpret the observed pressure response during the job and potentially make adjustments.

- **Fully 3D:** these fully three-dimensional programs are complex numerical modelling programs with extensive input data and high-end computing requirements. The fracture height, width, length and shape can all be calculated completely independently.
  This class of program is normally only found in research laboratories. Realistic predictions from any of these programs depend on accurate input data being available. This includes full geological data (formation boundaries etc.) and rock mechanical properties from sonic and density logs and from core measurements (Young's modulus, Poisson's Ratio etc.).

The extent of data provision required for specific case studies often limits the application of fully 3D programs to more generic studies evaluating the effects of changes in a given treatment or formation parameter.
The uncertain input properties can also be modelled probabilistically. The design can also be carried out using data-driven methods provided there is a sufficiently large database of the analogue fracturing results. All models assume that the two wings of the fracture are symmetrical (same height and length). Passive seismic measurements indicate that this is not always true.

Unlike the above, planar models, **unconventional models** are more recent, complex research programs designed to assess the fracturing performance in complex situations like shale gas formations, highly heterogeneous formations, naturally fractured reservoirs, presence of fissures (smaller fractures branching out off the main fracture), stress shadowing effect (i.e. disturbance of the rock stress due to a hydraulic fracture that affects another, nearby created hydraulic fracture in multi-fractured wells), etc.

6.4.1 2D FRACTURE PROPAGATION MODELS

The complexity of hydraulic fracturing models derives from the need to simultaneously satisfy two sets of laws:

- Conservation of momentum, mass and energy;

- Fracture propagation criteria that control the advance of the fracture tip.

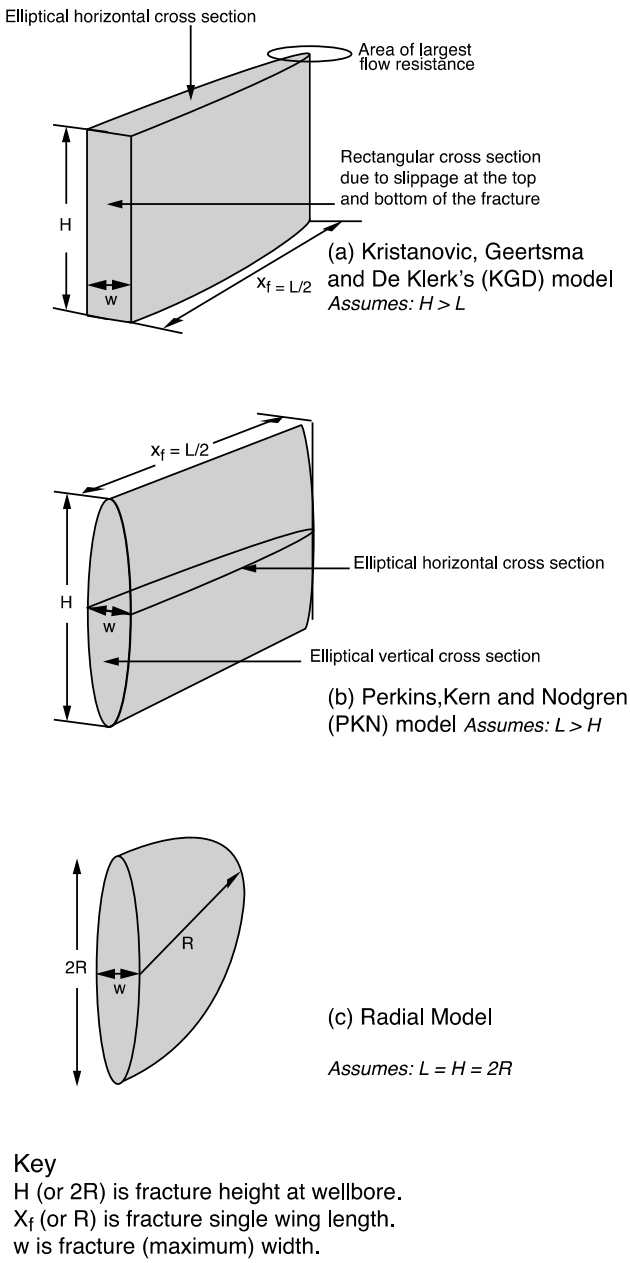


Figure 22 Fracture shapes predicted by two-dimensional hydraulic fracturing models

The types of two-dimensional (2D) models available are illustrated in Figure 22:

- The simplest solution available is when the fracture height is greater than the fracture length and free slippage occurs at the upper and lower boundary giving a rectangular shape at the wellbore. The fracture shape does not depend on the vertical position in the fracture (see Figure 22a). The FPP remains constant as the fracture grows longer. This 'KGD' model was introduced by Khristianovich, Geertsma and de Klerk.

- Another extreme situation is when the fracture is confined by boundary layers. It has an elliptical shape at the wellbore and the length is much greater than the height. Figure 22b sketches this model. The FPP decreases as the fracture grows longer. This 'PKN' model was introduced by Perkins, Kern and Nordgren.

- A limiting case between the two is the radial one when the fracture height equals the fracture length (Figure 22c).

As mentioned earlier, they require a value for the fracture height to be input. Within this constraint and when used in the correct application area (depending on the L/H ratio), they give results which agree well with the more complex models.

6.4.2 FRACTURE WIDTH

The preceding sections introduced the concept of fracture height containment. However, to be of practical use, the created fracture also has to be wide enough to admit proppant that will provide the permeable flow path from the reservoir to the wellbore after the fracturing treatment has finished. Pumping of the proppant when the fracture is not wide enough will lead to an immediate premature screen out (bridging of the proppant particles at the mouth of the fracture).

The simple 2D fracture models discussed above predict this width value (assuming negligible leak off a.k.a. the 'storage dominated' model assumption) as:

$$\omega_{max} \approx \left(\frac{\text{viscosity} * \text{pumprate}}{\text{Young's modulus}}\right)^{\frac{1}{4}} (\text{ISIP - FCP})$$

where ω_{max} is the maximum fracture width at the wellbore.

The quarter power means that changes in the viscosity or treatment pump rates over practical ranges have a limited effect on the fracture width e.g. increasing the viscosity or treatment pump rate by a factor three only increases the width by 32%. On the other hand, rock mechanical properties of the formation have a much larger impact:

- The Young's modulus can vary by a factor 100, from 1 x 10^5 psi in soft formations (soft chalks, diatomite, coals etc.) to 1 x 10^7 psi in strong sandstones as found in deep, low permeability formations.

- The fracture toughness – which controls the ease of (or excess pressure required for) fracture propagation and hence the value of the term (ISIP - FCP).

➢ *Feel free to attempt Tutorial 3*

The other asymptotic analytical solutions can be found assuming a very high leak off rate. In this case the leak off coefficient becomes the parameter mostly controlling the fracture width and length. Formulating the fracturing fluid to reduce the leak off coefficient is thus important, as is discussed below.

7. FRACTURING FLUID

Most modern fracturing fluids consist of a low concentration of a polymer dissolved in brine (typically along with clay control additives; and bactericide otherwise the polymers used can be damaged by bacteria). The polymer is normally guar gum or its derivatives (e.g. hydroxypropylguar HPG). This 'linear gel', dilute polymer solution's viscosity is high (normally tens of cP), but often not high enough to control fluid leak off and to transport proppant in conventional fracturing. It is further increased by joining the polymer molecules together with a crosslinking agent (e.g. borate), forming a much more viscous, molecular 3D structure. The gels used are 'shear-thinning' i.e. they show low apparent viscosity at high shear rates (hence showing moderate friction pressure loss in the tubing) and high apparent viscosity at low shear rates (thus becoming more viscous and able to transport proppant once in the fracture).

As explained earlier, during the fracture treatment this dilute polymer solution is pumped into the fracture at a pressure much greater than the reservoir pressure – resulting in a high percentage of the base brine "leaking off" into the formation. The large polymer molecules can be too large to be able to flow through the pore throat and hence form an external filter cake on the fracture surface. This is particularly true for the low permeability formations where fracturing is often applied. This decreases the leak-off coefficient and reduces the leak off rate, improving the fracturing performance. Generally, the leak-off rate is controlled by: the filter cake, the filtrate invasion zone, and the reservoir. The total leak-off coefficient is a combination of these three. In the formation with the high risk of fissure opening, fluid loss additives like silica flour or benzoic flakes can be also added.

The delayed-action, chemical breaker (normally enzymes, or oxidisers like ammonium persulphate) is normally dissolved in the fracturing fluid. There is sufficient chemical breaker present in fracturing fluid **within** the closed fracture to degrade the fluid viscosity after the pumping stops (e.g. once the fracturing fluids heats up in the closed fracture).

The properties and functions of the fracturing fluid have been discussed in many of the previous sections and are summarised in Table 5.

Fracturing Fluid Functions
(1) Initiate and propogate the fracture (2) Develop fracture width (3) Transport proppant thoughout the length of the fracture (4) Easily produced back to the surface after the fracture treatment is finished, leaving a fracture with the maximum permeability
Characteristics (Required to achieve the above)
(a) Stable, predictable rheology under surface and downhole treating conditions and treatment duration (b) Low friction pressures drop at high pump rates in tubing and flow lines (c) Provide fluid loss control (d) Clean and easily degradable to minimise formation damage to propped fracture (e) Compatible with reservoir formation and fluids (f) Economical / low cost

Table 5 Fracturing fluid summary

The fracturing fluid initiates and then propagates the hydraulic fracture; creating the required fracture width so that proppant can be admitted during the slurry stage. Gravity settling of the denser proppant in the less dense fracturing fluid will result in a higher concentration of proppant at the bottom of the fracture than at the top. This settling has to be controlled since ideally the proppant should be transported to the tip of the fracture. This is to ensure that the required (but not necessarily complete) fracture height is propped. (Some hydraulic fracturing treatments can take many hours to carry out; giving the opportunity for proppant settling.). Finally, the viscosity of the fluid in the completed and closed fracture has to decrease to a value similar to that of water so that a good fraction (typically 30-50%) of the base fluid can be later produced back to surface leaving a 'cleaner' fracture with the maximum possible retained conductivity.

These fracturing fluid functions can be translated into a series of characteristics which are needed to achieve the above.

- Points (1) to (3) in Table 7 require that the fluid has a stable and predictable rheology under both surface and downhole (treating) conditions. Thus the action of any cross linker used has to be stable at high temperature and high shear conditions, while the chemical breaker should not become effective prematurely, during the time taken to pump the treatment.

- Fluids have a highly shear-thinning rheology.

- The fracture volume is created by that proportion of the fracturing fluid (pad) which has NOT yet leaked off into the formation at the time the proppant slurry is added (see Figure 23). In practice, this "useful" portion of the pad, or its efficiency corresponds to 20% – 60% of the total volume pumped. Figure 23 also shows that the fluid leak-off occurs in a linear manner from the fracture face and can be described by a fluid loss coefficient with the units {volume/(area*√time) at a given distance/time.}

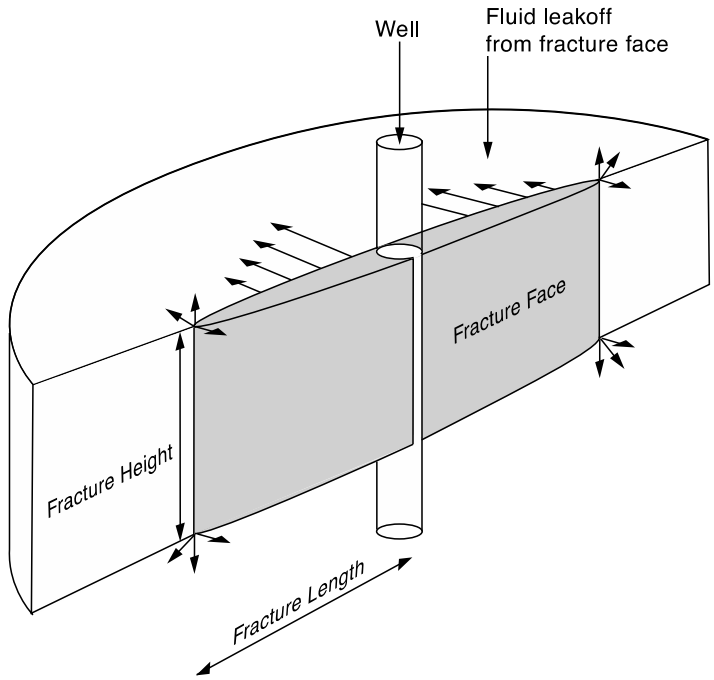


Figure 23 Fluid leak-off during hydraulic fracturing treatment

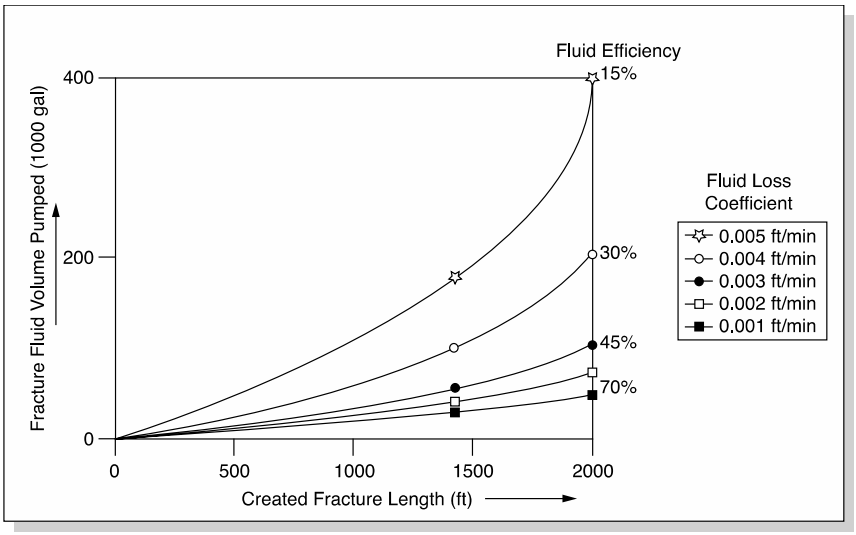


Figure 24 The fluid loss coefficient controls the created fracture length *(correction: the units in the legend should read ft/√min)*

Figure 24 schematically illustrates the effect of the value of this fluid loss coefficient on the created fracture length as a function of the fluid volume pumped. The higher the coefficient and the longer the fracture, the more difficult it is to increase the fracture volume further since most of the fluid pumped in will be leaking off the fracture faces instead of adding to the extra fracture volume.
This fluid loss coefficient determines the fluid efficiency, where:

$$\text{fluid efficiency} = \frac{\text{volume of fracture created}}{\text{total fracture fluid volume pumped}}$$

The best estimate of the fluid efficiency when designing a specific well hydraulic fracturing candidate is to measure the fluid efficiency during a mini frac treatment.

$$\text{fluid efficiency} = \frac{\text{constant} * (\text{fluid loss between ISIP and FCP})}{\text{total fluid loss to FCP or total volume pumped}}$$

Further, the fluid efficiency η can be used to calculate the required pad volume as:

$$V_{pad} = V_{total}\left(\frac{1-\eta}{1+\eta}\right)$$

Thus, for a given fracture volume the fluid efficiency can be used to calculate the total pumped volume, the pad volume, the (remaining) slurry volume, and the average proppant concentration (in lb/gal) given that the proppant bulk density is known and its total required weight can be found from the fracture volume.

This method of measuring the fluid loss coefficient to be further used as input into the fracture treatment design program produces the fracture design which automatically takes into account variations in the formation geology (the fracture may contact formation zones of higher and lower permeability compared to that observed at the wellbore).

- *Feel free to attempt Tutorial 4*

- The need for a fracturing fluid that is able to degrade to leave a maximum permeability propped fracture is discussed in detail later.

- Choosing a fracturing fluid which is compatible with the reservoir formation and fluids ensures that the leaked off fracturing fluid does not produce a zone of high formation damage next to the fracture face. However, due to the large inflow area of the fracture face, such a damage zone will have a much more limited impact on the formation inflow than similar skin values in the radial flow case.

  The preferred option is to choose a compatible fluid and to ensure significant formation damage does not occur.

- Low-cost solutions are always preferred! The fracturing fluid consists of a base gel prepared by diluting a concentrate polymer solution with the base fluid (normally water) and then adding one or more additives selected from:
  - Cross linking agents
  - Temperature stabilisers
  - Viscosity breakers
  - Clay stabilisers
  - Surfactants e.g. foaming or anti foaming agents
  - Fluid loss additives
  - Bactericide
  - Scale inhibitors
  - Buffers (that control the fluid pH e.g. acetic acid) etc.

The Service Companies market many, commercially available, fracturing fluid systems together with a wide choice of additives. In practice, an engineering compromise has to be made when selecting a particular fracturing fluid and judging its performance against the criteria listed above. A preferred choice for use when fracturing medium temperature wells is a fluid based on a low concentration (e.g. 40 lb/1000 gal) of Hydroxy Propyl Guar (HPG) polymer dissolved in a dilute brine with the addition of a borate ion cross linking agent. This fluid meets the Table 7 criteria while the low polymer concentration minimises the cost and maximises the retained fracture conductivity.

The alternative, though often more expensive and complex, fracturing fluids include:

- Viscoelastic surfactant (VES) fluids. They degrade more efficiently than polymer gels.
- Nitrogen or CO_2 can be added to water at a concentration (a.k.a. 'quality') either less than 52% (a.k.a. 'energized fluid') or above 52% (foam, stabilised by surfactant and optionally viscosified by gels). They assist flowback and fracture cleanup and are useful in tight and /or depleted and/or water sensitive reservoirs.
- Polyemulsions of oil and water, stabilised by polymers, are more viscous and less damaging.

Slickwater (brine with added polyacrylamide-based Friction Reducer (FR), reducing the apparent viscosity at high shear rates) is often used as a pre-pad; and also as the fracturing fluid in unconventional fracking where leak off is less of a problem.

8. PROPPED FRACTURE CONDUCTIVITY

As mentioned, the proppant used is either well-sorted sand from sand mines, or artificial: most often ceramic, sintered, made of aluminium ore (bauxite). The proppant qualities: permeability, porosity, and ability to withstand the fracture closure stress are related to its properties: sphericity, roundness, sorting, strength. The proppant size is normally expressed by its mesh size: i.e. the 20/40 proppant is small enough to pass through the mesh with 20 openings per linear inch, but big enough to be stopped by the mesh with 40 openings. (Correspondingly, the 20/40 proppant grains are smaller than e.g. the 12/20 ones but larger than e.g. 40/60.) The artificial proppant's density increases with its strength. E.g. the sand (quartz) specific gravity is around 2.65, whereas the stronger bauxite's is 3.9. Larger size proppant shows higher porosity and permeability than the smaller size one. However, increase in both density and size of proppant increases its settling rate in the fracturing fluid, making it difficult to transport within the fracture. For illustration see e.g. the Stokes law for the particle (e.g. a proppant grain) settling velocity in a stagnant Newtonian fluid:

$$v_{settl} = \frac{g(\rho_{prop} - \rho_{fl})d_{prop}^2}{18\mu_{fl}}$$

The proppant placed within the fracture is stressed as the fracturing fluid leaks away and the fracture closes. Once this happens this fracture closing stress (FCS) acting on the proppant is equal to the minimum in-situ effective stress (σ'_h) where:

$$FCS = \sigma'_h = \sigma_h - P_{frac}$$

where P_{frac} is the fluid pressure within the fracture (very close to P_{wb}). Since the fracture or wellbore pressure normally decreases with production time, it is assumed zero in conservative, worst case scenario estimates of the stress acting on proppant.

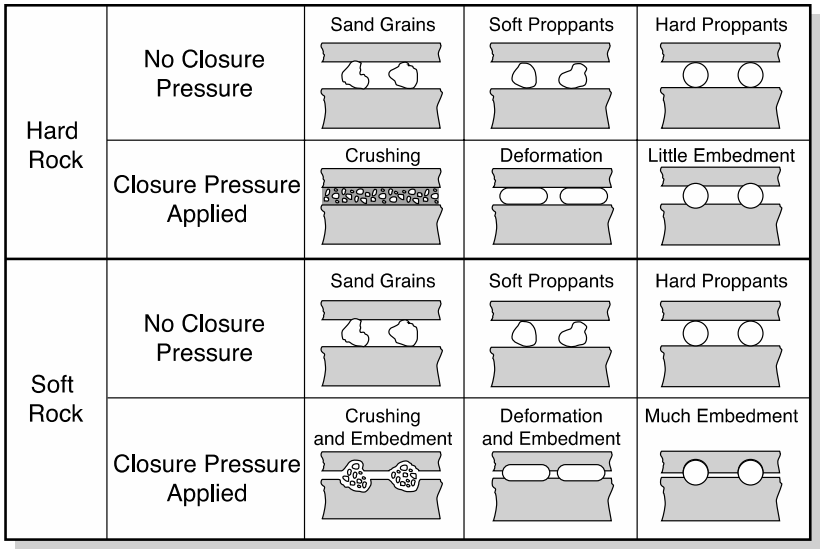


Figure 25 Behaviour of proppant under stress

Figure 25 illustrates how this fracture closing stress will result in changes to the fracture width and conductivity which depend on the strength properties of both the proppant and the formation:

- Crushing of the proppant grains leading to reduced proppant permeability, and hence reduced fracture conductivity. The crushed fragments (proppant fines) can migrate and plug the proppant porosity;

- Deformation of (soft) proppants which leads to a reduced fracture width, and hence reduced fracture conductivity;

- Embedment of the proppant in the fracture wall, leading to a further reduction in the fracture width and conductivity.

Some available proppant types are listed in Table 6 while Figure 26 schematically illustrates the variation in permeability as a function of closure stress (*note that steel platens were substituted for the fracture wall in the experiment so that negligible proppant embedment occurred*).

Proppant Type	Proppant grain permeability for a given grain size distrubution	Resistance to Crushing	Cost
Low Quality Sand	Low	Low	Low
High Quality (Ottawa) Sand	↕	↕	↕
Resin Coated Sand			
Intermediate Strength Proppant (Ceramic)			
High Strength Proppant (Bauxite)	High	High	High

Table 6 Proppant types. *(NB: ceramic proppant types can be further classified into lightweight ceramic (LWC) proppant, Intermediate Density Ceramic IDC, High Density Ceramic HDC, and Ultra HDC one.*

The more rounded a proppant is, the higher its permeability will be for the same proppant size and the greater its strength since the fracture closing stress will be spread more evenly over the proppant grain's surface. Thus:

- The low-quality sand {with its multi-crystalline, angular (i.e. not well-rounded) grains} began to crush at low stresses (< 2,000 psi).

- The high-quality sand (well rounded, mono-crystalline grains) shows a much greater stress resistance.

- Bauxite, a high strength proppant, showed negligible grain crushing and only a small amount of deformation; even at the highest closure stresses (10,000 psi). It can however cost as much as 10 times the conventional sand.

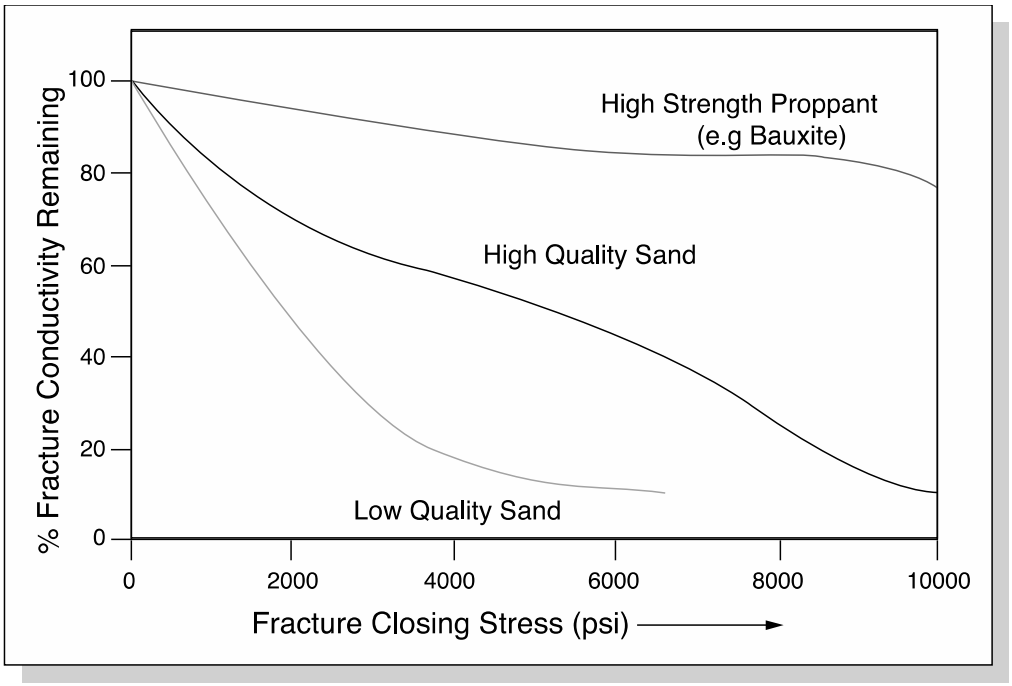


Figure 26 Fracture conductivity variation with stress

Resin coated sand shows better performance than the uncoated sand because the resin tends to bond (glue) the grains together, distributing the load over them better, while also keeping the crushed fragments in place. Resin coated sand also shows smaller proppant flowback from the fracture during production.

9. THE FRACTURING FLUID AND THE FRACTURE CONDUCTIVITY

Ultimately, it's the fracture length and conductivity that define the resulting well productivity and the job success.

As mentioned, most modern fracturing fluids consist of a low concentration of a polymer dissolved in brine. There is sufficient chemical breaker present in fracturing fluid **within** the closed fracture to degrade the fluid viscosity, however it is not capable of completely destroying the filter cake, which remains in the fracture and reduces the fracture conductivity (see Figure 27).

The efficiency of the removal of the remnants of the fracturing fluid from the proppant pack itself is measured by the Retained fracture conductivity where:

$$\text{Retained fracture conductivity} = \frac{(\text{conductivity after exposure to fracturing fluid x } 100\%)}{\text{conductivity prior exposure to fracturing fluid}}$$

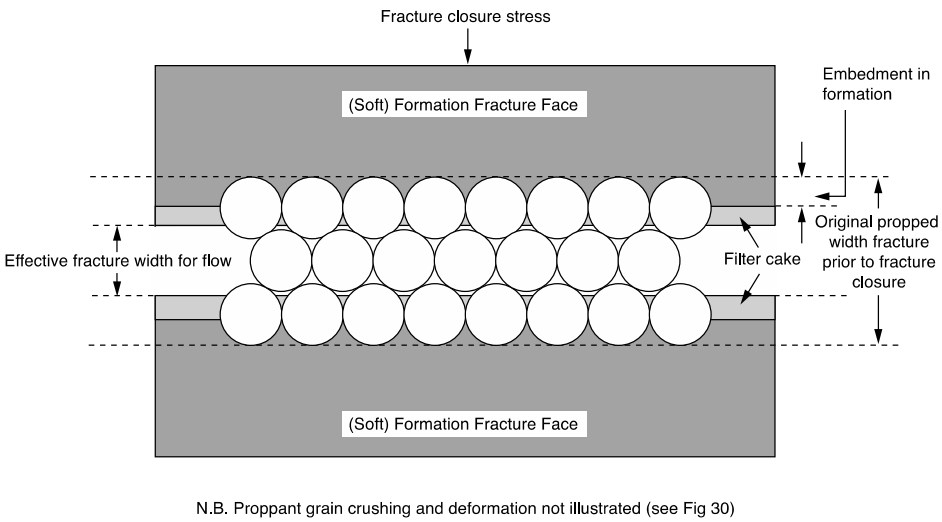


Figure 27 Actual hydraulic fracture conductivity

Naturally, the type and concentration of polymer used to prepare the fracturing fluid affects the fracture conductivity. This is illustrated in Figure 28 for different fracturing fluids – retained fracture conductivities of between 50% and 100% are observed.

N.B. As mentioned, the skin effect due to the filter cake or the *fracturing fluid – reservoir rock* incompatibility has little effect on the reservoir inflow performance providing the permeability damage is not excessive e.g. (k_{damage} / $k_{original}$ < 0.5). This is due to the large inflow area of the hydraulic fracture surface. The effective fracture width open to flow and the proppant permeability are the key parameters controlling the fracture flow capacity.

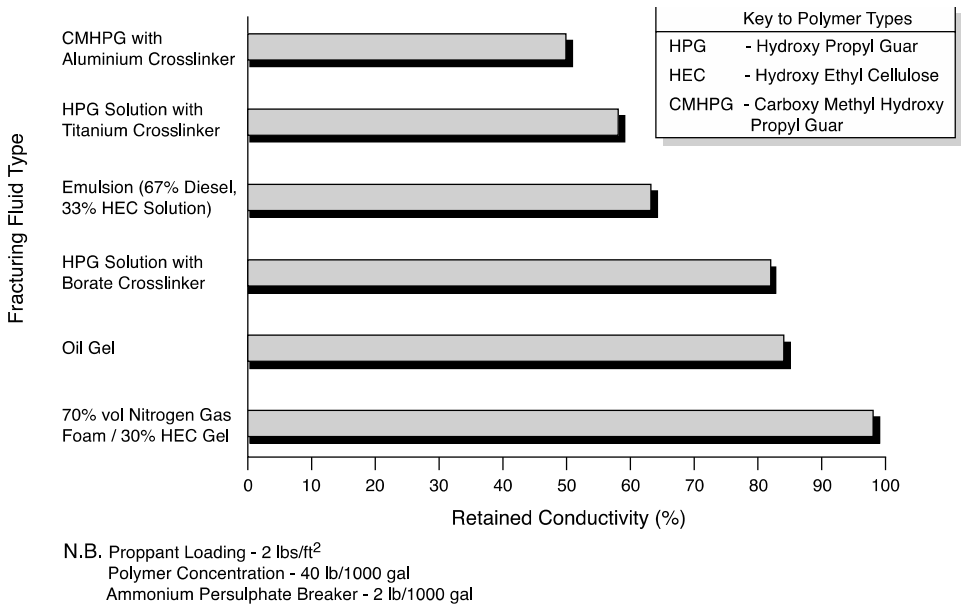
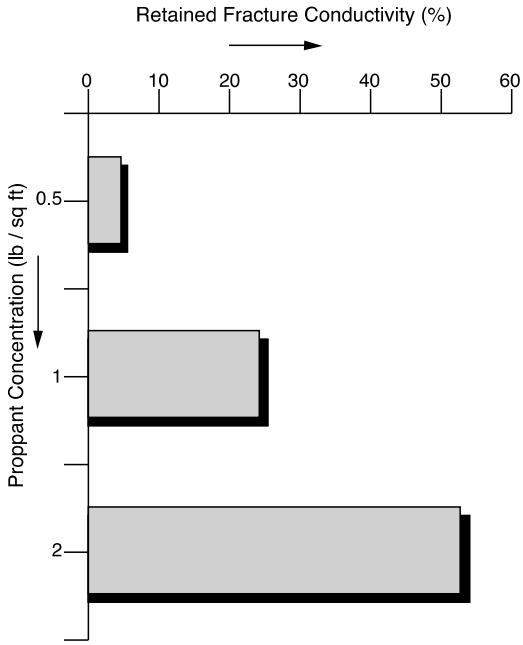


Figure 28 Typical values for fluid type and retained fracture conductivity

It can be surmised from Figure 27 that the values of the measured fracture conductivity are dependent on the fracture width or the number of layers of proppant (e.g. there are three proppant layers in Figure 27). This is because embedment of the proppant layers in the fracturing fluid filter cake and in the fracture face itself becomes progressively more important to the final fracture conductivity as the number of layers of proppant grains decreases. The number of layers of proppant is related to the 'proppant loading' i.e. the weight of proppant per unit area of the fracture – a measure used in lab experiments and fracture design.

Figure 29 summarises experiments performed at varying proppant loadings. They clearly show that the filter cake effectively destroys the fracture conductivity at low proppant concentrations.



Experimental Conditions	
Fracturing Fluid	40lb / 1000 gal HPG
Cross Linker	Titanium
Chemical Breaker	2lb / 1000 gal (ammonium persulphate)
Proppant Loading	0.5 - 2 lb / ft^2
Proppant Type	Ottawa Sand

Figure 29 Typical values for proppant loading and retained fracture conductivity

The chemical breaker added to degrade the fluid viscosity is capable of partially destroying the filter cake. This is made clearer in Figure 30 where an increase in the breaker concentration, in this case ammonium persulphate, results in greatly increased retained fracture conductivity. However, addition of large concentrations of breaker to the fracturing fluid is not a viable approach since this will result in the fluid viscosity being degraded **during**, rather than **after**, the hydraulic fracturing treatment. This early decrease in fracturing fluid viscosity will prevent the (denser than fluid) proppant being transported to the tip of the fracture. Instead, the proppant will sink to the bottom of the fracture under the influence of gravity and a premature screen out can result.

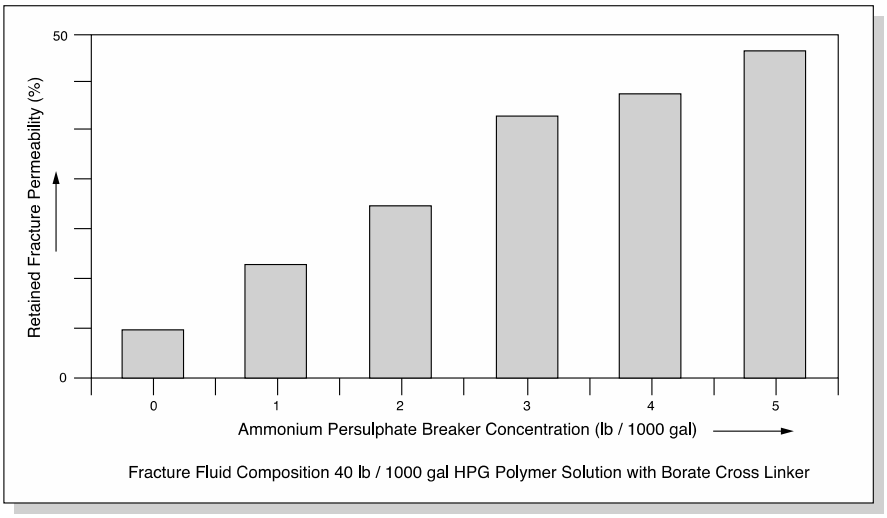


Figure 30 Chemical breaker concentration and retained fracture conductivity

PROPPANT	FRACTURING FLUID	FRACTURE GEOMETRY & PRODUCED FLUID
Size (Average Grain Size and Grain Distribution)	Polymer Type and Concentration	Fracture Width (especially at wellbore)
Grain Roundness & Sphericity	Fluid Loss Additive Type and Concentration	Reduced Permeability- due to Non-Darcy or turbuent flow effects at high flow rates and multiphase flow
Proppant Crush Resistance & Fracture Closure Stress	Crosslinker Type and Concentration	
Time	Breaker Type & Concentration control when viscosity decreases	Reservoir temperature will control fluid additive selection

Table 7 A summary of factors affecting proppant conductivity

Overall, the factors which influence the effective proppant permeability when placed in the fracture are summarised in Table 7.

On top of the retained proppant permeability, the other factors that control fracture conductivity include the:

- Fracture width
- Reduced effective permeability due to:
  - High rate (non-Darcy or turbulent), flow effects. These can be particularly important when stimulating gas wells.
  - Multiphase flow effects (as observed during oil production).
  - Greater activity from the chemical breaker at higher bottom hole temperatures leading to greater retained fracture conductivity or, if the breaker activates too early, in the early loss of fracture fluid viscosity leading to premature proppant settling.
  - Gradual "clean up" (reduction in water saturation from the fracturing fluid in the near-fracture formation). This leads to a long-term increase in the effective permeability of this formation situated next to the hydraulic fracture and preferential production from this formation. This process can take many months after hydraulically fracturing a low permeability formation.

Generally, the fracture conductivity should be high enough to match the reservoir inflow. It is observed that in reservoirs with permeability less than 5 mD any reasonable fracture conductivity is likely to be sufficient and thus is less important to worry about compared to the fracture length when it comes to the well productivity. In higher permeability reservoirs both the fracture conductivity and length should be optimised. In high permeability reservoirs (> 50 mD) the fracture conductivity is key, as will be explained later in relation to the Tip Screen Out fracturing technology.

10. HYDRAULIC FRACTURING IN PRACTICE

Hydraulic fracturing is a complex operation requiring much specialist hardware and preparation. The scale of the equipment needed is defined by the scale of the frac job: this can vary from the jobs of regular size with an average of 60k gal of fluid and 100k lb of proppant, to higher-scale, 'massive' hydraulic fracturing (MHF) when creating multiple fractures or large fractures (e.g. a fracture several thousand ft long, several hundred ft high, and 0.25-2 inch wide), needing somewhat over 1 million gallons of fluid and over 5 million pounds of proppant, although the definition of MHF varies. The pump pressures and rates in HF can reach over 10,000 psi and 50 bbl/min.

The equipment required for a Massive Hydraulic Fracturing (MHF) treatment on land is schematically illustrated in Figure 31. It is a.k.a. 'frac fleet' or 'frac spread'.

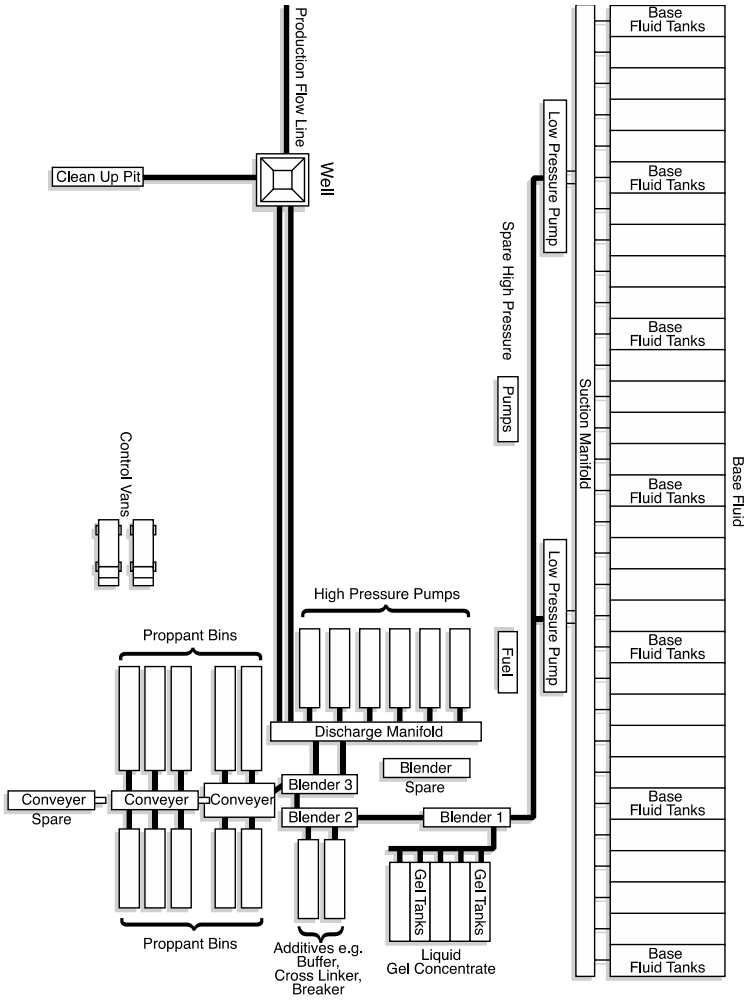


Figure 31 Equipment for a massive hydraulic fracturing treatment on land

- The base fracturing fluid (a brine compatible with the formation e.g. 1% wt KCl solution, and with bactericides added) is placed in a series of clean tanks which are manifolded together.

- A low-pressure pump transfers the fluid to blender No 1 where it is mixed with a concentrated polymer gel solution to give a typical polymer concentration of 40-100 lbs/1000 gal. Sufficient residence time combined with intense agitation within the blender ensure the gel is properly hydrated (dissolved) in the base fluid. Once hydrated, its long-chain molecules stretch and increase the fluid's viscosity.

- The base gel is transferred to blender No 2 where additives such as crosslinking agents, buffer, breakers, surfactants etc. are added. Quality control checks are carried out to ensure the (cross-linked) gel has the desired properties i.e. the additives are being added in the correct amounts and no contaminants are present. Proppant is also added in blender No 3.

- The proppant was loaded into bottom discharge bins prior to the commencement of the fracturing treatment. It is transported to the blender using a moving band conveyor. Measurement of the proppant slurry density ensures that the correct addition rate of proppant is being achieved.

- Blender No 3 transfers the prepared fracturing fluid or slurry to a number of high-pressure pumps manifolded in parallel. The pumps must be sufficiently powerful to be able to pump to the well the fluids/slurries at the required pressure and rate. A dual, high pressure flow line is often provided between the pumps and the well to minimise frictional pressure losses.

- The instrumented control van allows the "frac master" to monitor the treatment progress, to order adjustments to be made as required and to cope with operational problems e.g. faulty pumps, conveyors etc. as they occur.

- Spare or standby pumps, blenders, conveyors, etc. should be hooked up and operational before the treatment commences. This ensures failures have a minimal impact on the treatment progress.

- A fuel tank is required to ensure that all the engines that are driving the pumps, blenders etc. have sufficient fuel for the treatment duration.

- At the end, the proppant slurry is displaced with the base gel to just above the perforations and the pumps are stopped. The well is shut in for sufficient time to allow the fracture to close and the fracturing fluid's viscosity to degrade. The well may now be placed on production. Initially only the degraded fracturing fluid will be produced back – this can be directed to a clean-up pit. Once hydrocarbons are being produced the well production should be directed to the facilities via the production flow line.

The process for fracturing an offshore well is essentially the same as the above, although all the equipment is installed in a specially designed stimulation boat (Figure 32). Sea water is often used as the base fluid, reducing the fluid storage requirements.

Carrying out a hydraulic fracturing treatment is an expensive, complex undertaking.

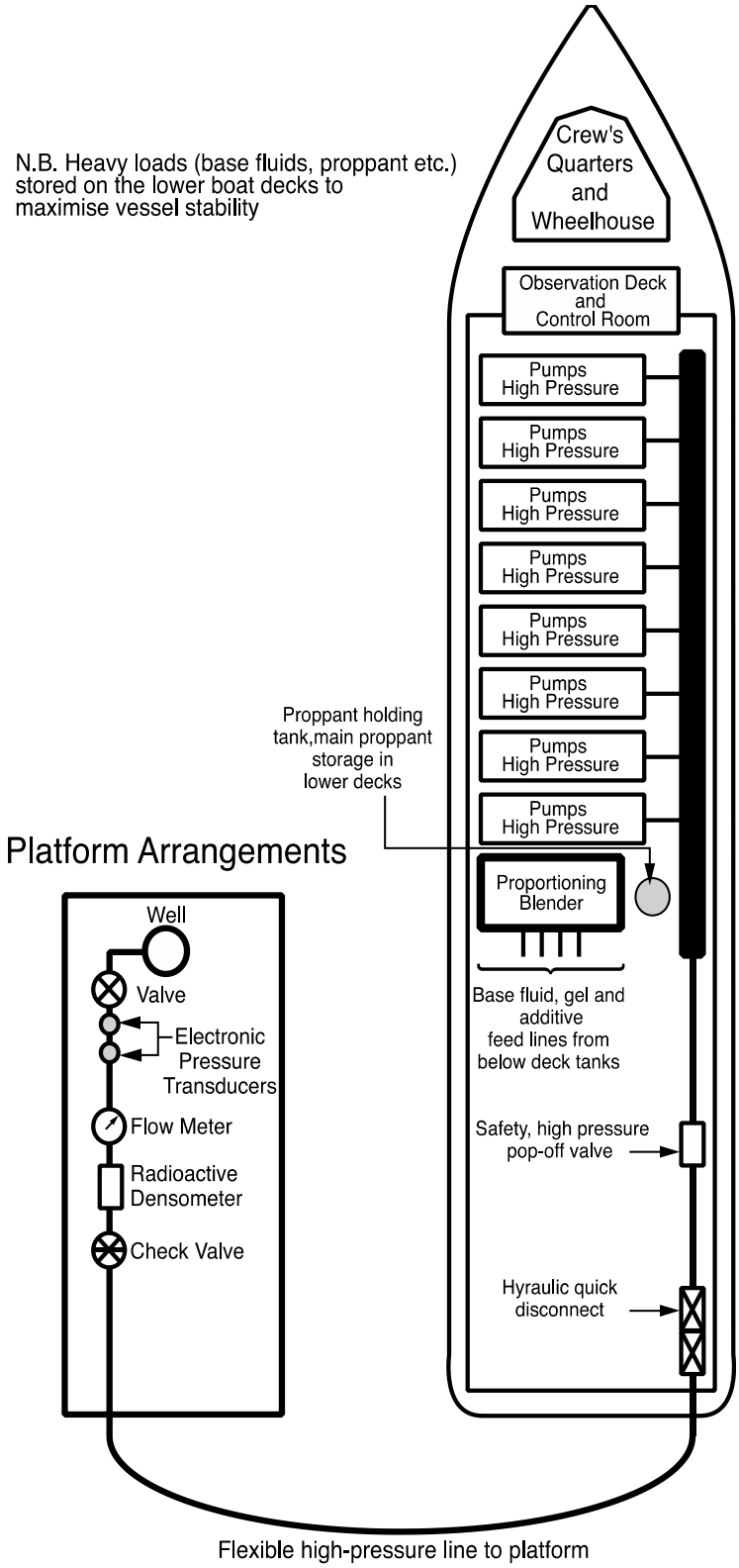


Figure 32 Layout of an offshore stimulation vessel

11. FRACTURE-STIMULATED WELL INFLOW PERFORMANCE

The Inflow Performance of a Fracture-Stimulated well is controlled by the dimensionless Fracture Conductivity (F_{cd} a.k.a. C_{FD}):

$$F_{cd} = \frac{k_f * w}{k * L_f}$$

where:

k_f*w = fracture permeability (k_f) * conductive fracture width (w)
≈ ability of the hydraulic FRACTURE to conduct fluid to the wellbore
= the fracture conductivity.

k*L_f = formation permeability (k) * conductive fracture single wing length (L_f)
≈ ability of the FORMATION to deliver fluid to the hydraulic fracture.

These parameters are illustrated in Figure 33. It can be easily visualised that the objective of the propped hydraulic fracture treatment design process is to ensure that the pressure drop down the length of the fracture is low compared to the pressure drop across the formation. Thus, as much as possible of the well drawdown should be taken across the reservoir with the pressure drop within the fracture making a negligible contribution to the total value of the well drawdown. We will now consider these two factors in turn:

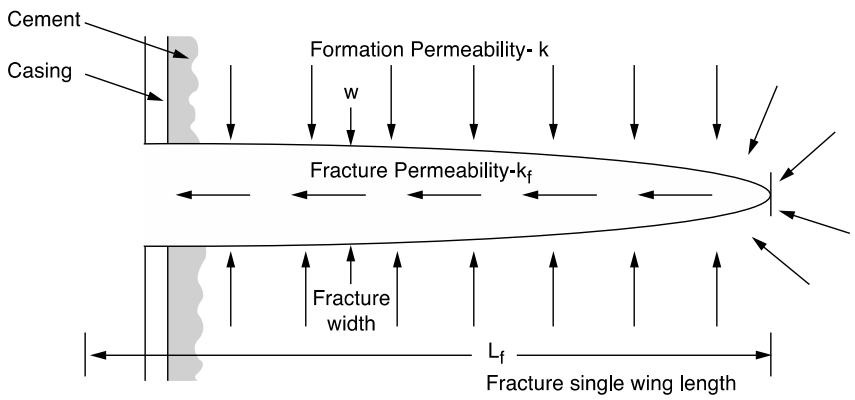


Figure 33 Factors contributing to the dimensionless fracture conductivity

As mentioned, the fracture conductivity is **increased** by:

- An **increased fracture width** (w),
- An **increased proppant permeability** (large, more spherical, proppant grains have a higher permeability) and
- **Minimising the permeability damage** to the proppant pack due to the fracturing fluid retention.

Frequently the increased production achieved by carrying out a hydraulic fracturing treatment is represented by the "Productivity Improvement Factor" PIF a.k.a. "Folds of Increase" FOI:

$$FOI = Q_f/Q_o$$

where
$$Q_o = \frac{2\pi k.h\left(\bar{P}_R - P_{wf}\right)}{\mu_o.B_o.\ln\left(r_e / r'_w\right)}$$

and
$$Q_f = \frac{2\pi k.h\left(\bar{P}_R - P_{wf}\right)}{\mu.B_o.\ln\left(r_e / r'_w\right)}$$

Q_o and Q_f are the well production rates under equivalent conditions before and after carrying out the hydraulic fracturing treatment. Thus:

$$FOI = \frac{\ln(r_e/r_w)}{\ln(r_e/r_w)+s_f}$$

(Remember the skin factor S_f of a fractured well is negative). Typical FOI of a MHF in conventional reservoirs is around from 2 to 5.

There have been several studies of the composite effect of fracture length, fracture conductivity and formation permeability on the well inflow performance. A widely used correlation for a planar vertical fracture is that by Cinco-Ley and Samaniego (Figure 34). This figure shows that a minimum F_{CD} value of 10-15 is required to ensure that the well inflow is not being limited by the fracture conductivity. An alternative presentation (Figure 35) allows the (negative) skin effect due to the propped hydraulic fracture (S_f) to be calculated from the dimensionless fracture conductivity.

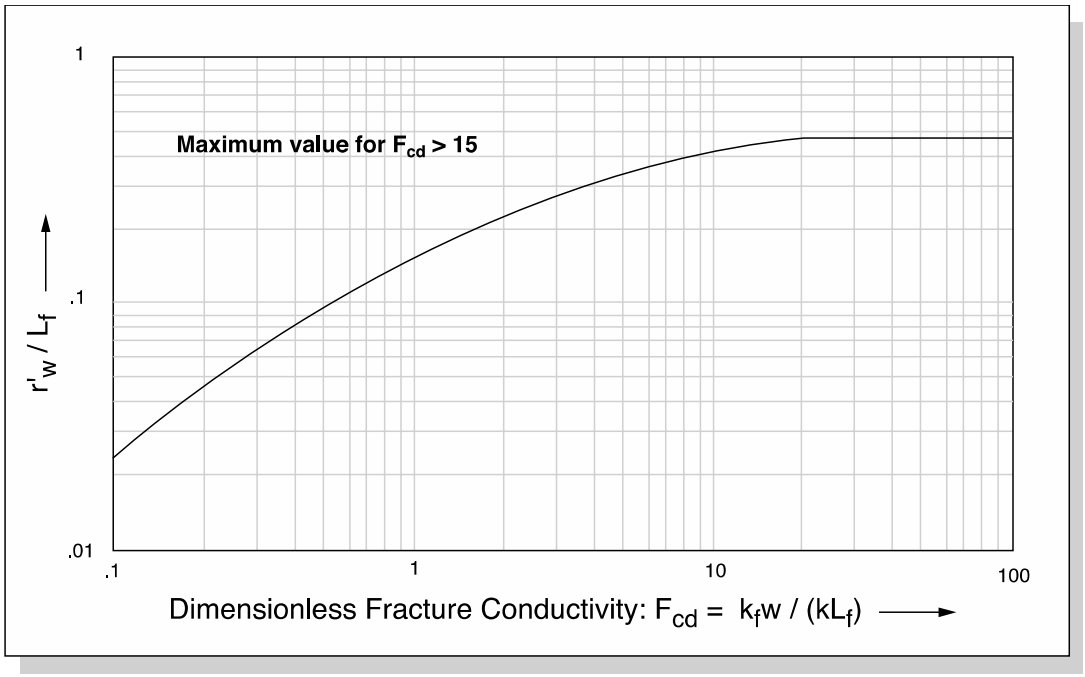


Figure 34 Correlation between effective wellbore radius and fracture conductivity (Cinco-Ley and Samaniego, 1981)

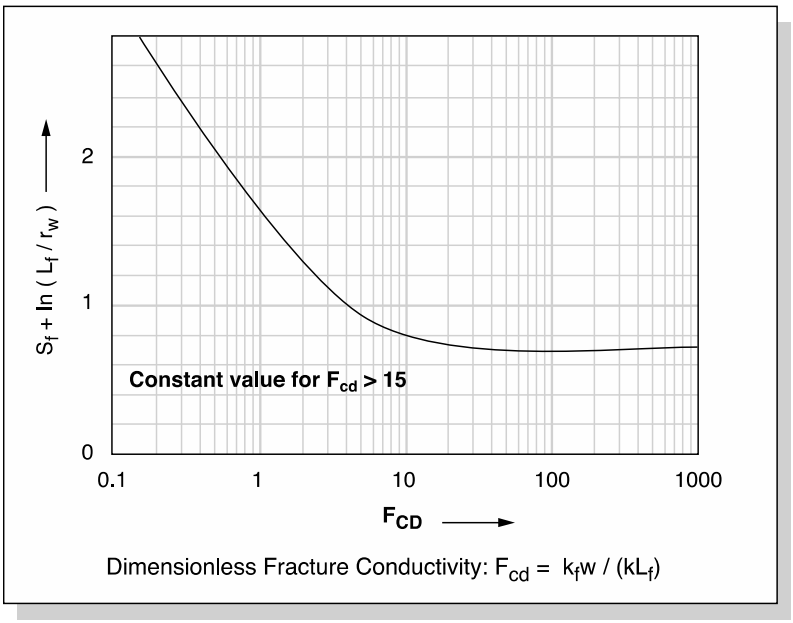


Figure 35 Fracture skin effect varies with fracture conductivity

The above correlations and equations can be used to quantify the relationship between the increased production (FOI) as a function of the fracture length (L_f), formation permeability (k) and the fracture conductivity (k_f*w). Figure 36 shows that for wells in **low permeability (0.1mD) formations:**

- High values of the FOI are possible;
- FOI is related to fracture half length, while the fracture conductivity has a limited effect, providing its value is greater than a certain minimum.

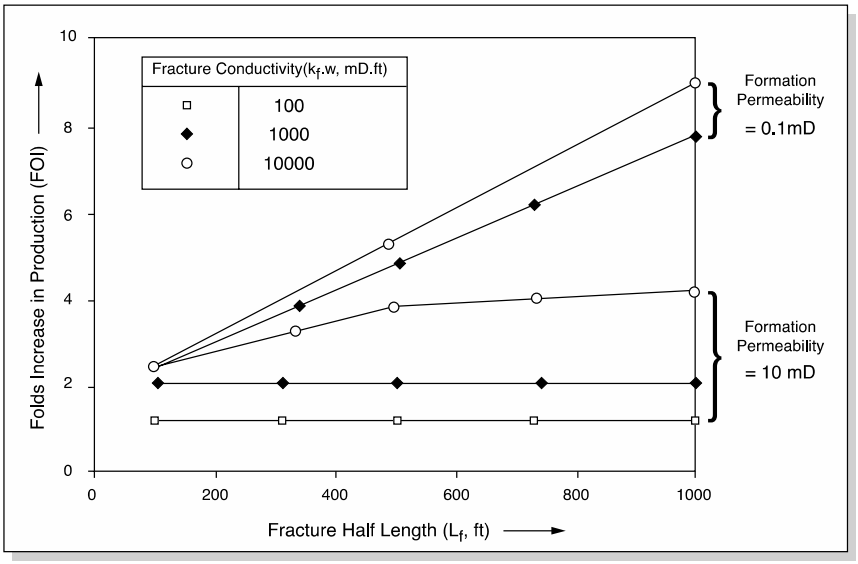


Figure 36 Well productivity response to hydraulic fracturing

The (low) formation permeability is controlling the well inflow and so increased fracture conductivity does not much improve well inflow performance.

An increase in the formation permeability to 10 mD results in a different picture:

- A fracture with a low conductivity (100 mD.ft) has essentially no effect on the well production;
- Increasing the fracture conductivity by a factor 10 (to 1,000 mD.ft) increases the well production (or FOI), but the FOI is still independent of fracture length for its values greater than 100 ft;
- A further increase to 10,000 mD.ft is required before the inflow performance becomes sensitive to the created fracture length i.e. the fracture conductivity is no longer the only limiting factor in well inflow performance.

Inflow from the formation **into** the fracture is no longer the controlling factor for this higher permeability reservoir. The above considerations will control the hydraulic fracture treatment design process since long and highly conductive fractures are more difficult to make and have a greater cost.

➢ *Feel free to attempt Tutorials 5-6*

12. OPTIMISATION OF HYDRAULIC FRACTURE DIMENSIONS

The expense of carrying out a hydraulic fracturing treatment dictates that the propped hydraulic fracture parameters are carefully optimised to generate the maximum discounted net present value (NPV) related to the project's profit. Part of this process is illustrated in Figure 37. It consists of three strands:

(A) Using a well performance computer program to quantify post-stimulation gain.

(B) Using a hydraulic fracture design program to quantify the stimulation size and costs.

(C) The results from A and B which are combined to generate a plot of Net Present Value against the fracture length.

A well performance prediction computer program is used to generate a plot of well production rate against time for various fracture lengths (L_f) (Figure 37a). We assume a high {C_{FD} > 15} dimensionless fracture conductivity in this example. As discussed above, longer fractures will give higher production rates. These figures can be translated into a plot of cumulative production against time, for each fracture length (Figure 37b), and then further into a plot of discounted revenue against fracture length (Figure 37c). Longer fractures generate more revenue, but the rate of revenue increase decreases as the fracture length increases.

The second strand of the process (B) uses a computer program for hydraulic fracture treatment design to generate estimates of the fluid volume required for a number of fracture lengths (Figure 37d). These volumes may be equated with treatment cost (Figure 37e) – as expected, longer fractures require more volume and are more costly to produce. Further, the rate of cost increase becomes larger as the fracture length increases.

Finally, the data from Figure 37c and Figure 37e are combined in the fracture optimisation strand (C) to give a plot of the project's net present value. The trends in the bottom two figures ensure that there is a fracture length which gives the maximum project profitability (Figure 37f).

The above describes only a part of the treatment optimisation process since the fracture conductivity (a combination of proppant type, size and impairment from residues left behind by the fracturing fluid) and fracturing fluid selection all impact the treatment cost.

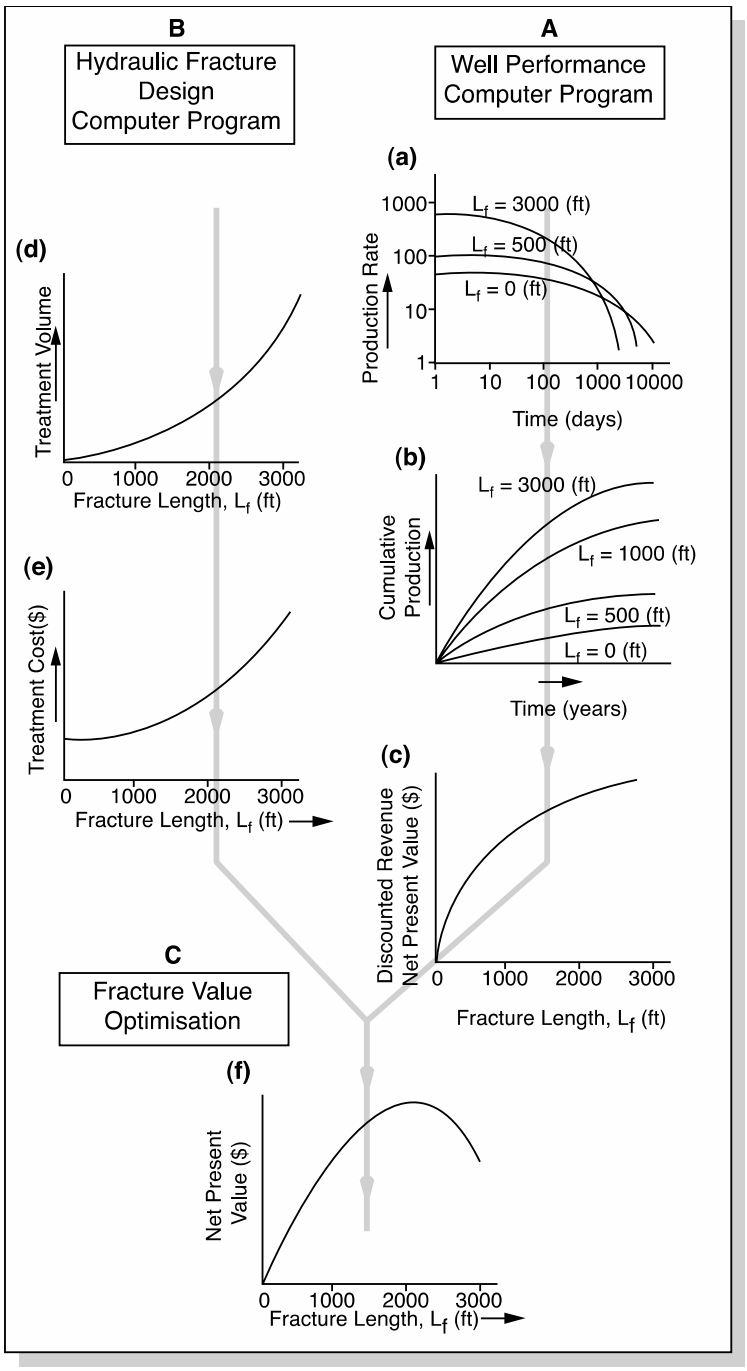


Figure 37 Part of the process to optimise the dimensions of a hydraulic fracture

13. TIP SCREEN OUT FRACTURING

So far, this Chapter has described the carrying out of a conventional, hydraulic fracturing treatment designed to stimulate wells completed in low permeability formations with long, thin fractures.

The capabilities of hydraulic fracturing technology have been extended into medium-to-high permeability formations. A shorter and wider fracture design is more beneficial in this case. This involves the hydraulic fracture treatment design to deliberately create an early Tip Screen Out (TSO). This process involves the pumping of the proppant slurry early during the fracturing treatment. When the first proppant arrives at the fracture tip it forms a "bridge", or proppant plug at the tip (hence the TSO effect). The process is explained in Figure 38.

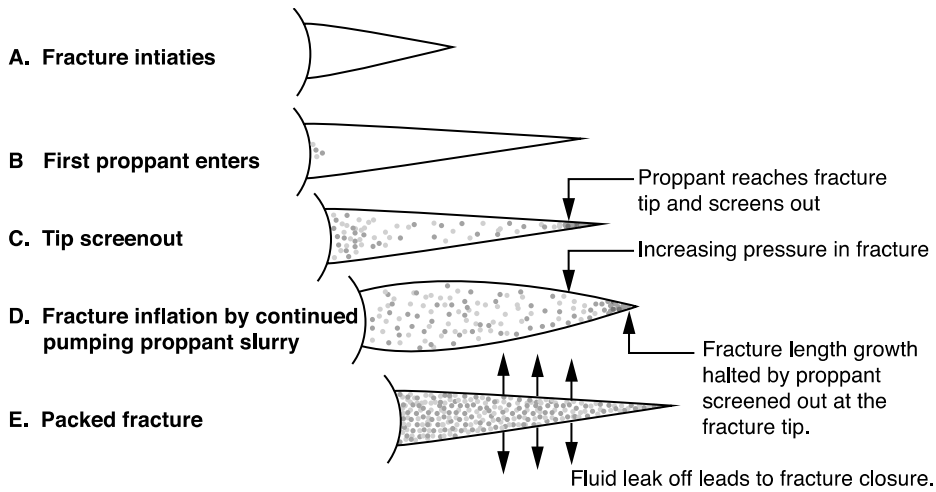


Figure 38 Fracture width inflation with the tip-screenout technique.

The proppant plug has a relatively high pressure drop across it compared to the fracture. This reduces the fluid pressure acting on the fracture tip, so that further fracture length growth is halted and fracture width growth can begin to provide the extra fracture volume to accommodate any further volumes of proppant slurry injected into the fracture. This results in an increase of the BHP and the fracture is no longer increasing in length.

A real TSO treatment example history is schematically illustrated in Figure 39 and Table 8. The treatment proceeded as follows:

- The fracturing fluid used was a low concentration (40 lb/1000 gal) HPG polymer solution with a borate cross linker (as recommended earlier).

- The treatment was started with a pump rate of 5 bbl/min. Fracture re-opening was confirmed by a peak in the downhole pressure, followed by a slow decrease as the fracture extended in length.

- After 13 minutes the pump rate was increased to 25 bbl/min – with a corresponding rise in treating pressures. A much greater increase was observed in the surface measurement since the increased

pump rate gave rise to some 3000 psi extra frictional pressure drop across the tubing.

- Pumping of proppant slurry was begun after 23 minutes with the first proppant arriving at the perforations some 3 minutes later. The bottom hole pressure began to increase after 28 minutes. The tubing head pressure drops between 28 and 30 minutes because the proppant containing slurry is denser than the fracturing gel that filled the tubing in the previous stage.

- Pumping of the higher proppant concentrations – stage 3 began at 30 minutes. The bottom hole pressure continued to rise smoothly while the tubing head pressure shows a much steeper increase in pressure after 33 minutes – the denser proppant slurry has an increased viscosity compared to the cross-linked gel alone.

- The final proppant stage was pumped (stage 4) and displaced to the perforations (stage 5).

Figure 39 and Table 8 show that the crucial stage of this fracturing treatment occupies a very short time period – 67% of the proppant is pumped in only a 5 minute time period. Also, the total treatment took less than 40 minutes.

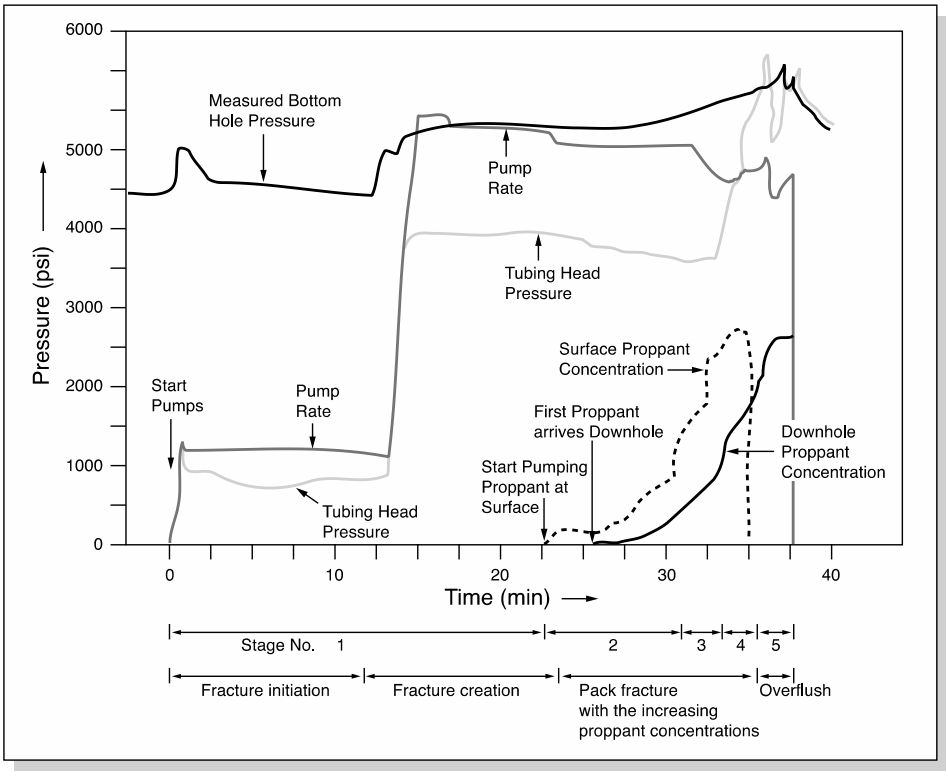


Figure 39 Treatment record for tip screen out hydraulic fracture stimulation

Stage	Fluid	Volume (gals)	Proppant Consentration (lb/gal)	Cumulative Proppant (pumped lb)
1	Fracturing Gel Creates Fracture	15,000	0	—
2	Dilute Slurry	7,000	0-4 (increasing)	16,000
3	Concentrated Slurry	3,500	4-12 (increasing)	36,000
4	Very Consentrated Slurry	1,000	12	48,000
5	Base Fluid Overflush	1,800	0	—

Table 8 Pumping schedule for tip screen out hydraulic fracture stimulation treatment

These figures should also be compared with the equivalent ones for a massive hydraulic fracture (MHF) stimulation treatment. The TSO fracture uses only 5% of the amount of proppant and 10% of the fluid volume a conventional MHF would use. These differences between the two types of treatment are summarised in Table 9 and Figure 40.

Fracture Type	Conventional (low permeability formations)	Tip Screen Out (medium permeability formations)
Description	Long and Thin, (Low Conductivity)	Short and Fat, (High Conductivity)
Width (inches)	> 0.25	0.25 - 1.5
Length (ft)	500 - 1500	50 - 500
Proppant Concentration (lb / ft^2)	0.5 - 2.0	4 - 12

Table 9 Tip screen out and conventional fracturing compared

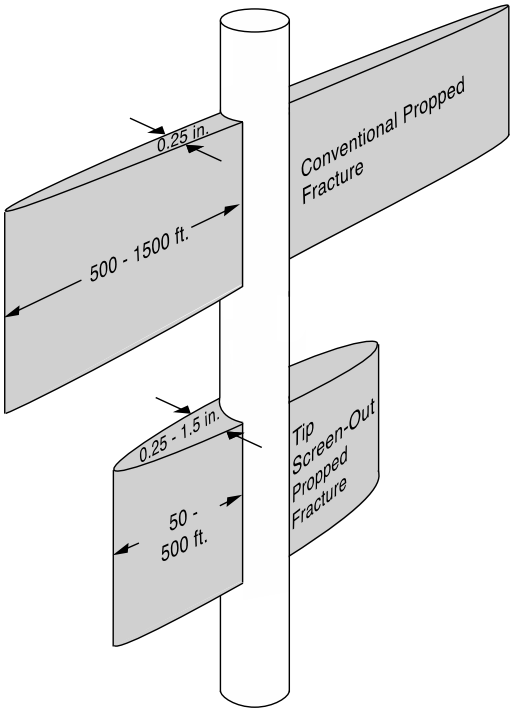


Figure 40 Tip screen out and conventional fracturing compared

13.1 Applications of TSO Fracturing

TSO fracturing is a field proven technology for use in a number of areas.

(1) **Sand control:** gravel packing and fracturing are combined into a single operation. This is called "Frac and Pack" (or 'fracpack'). In addition, a number of successful field trials in which fracturing alone was used have been reported (successful sand control was attributed to the reduced flow velocities associated with the TSO fracture compared to a conventional perforated completion).

(2) **Alternative to matrix acidizing:** using highly conductive fractures to bypass near wellbore formation damage. Successful matrix acidizing often requires that the source of formation damage be identified in order to select the optimum acid formulation. In contrast, TSO fracturing has the advantage that it is independent of the type of formation damage. This type of treatment is generally called a "skinfrac".

(3) **Reserve increase in laminated sands:** well completion in formations consisting of finely laminated sands is problematic since there is a high chance that the perforation density will not be sufficient for the well to make contact with all the hydrocarbon bearing zones. Production via a TSO fracture will ensure that recovery is achieved from all the zones.

(4) **Production of medium viscosity oil from lower permeability formations:** the increased production rates achievable using TSO fracturing can sufficiently improve the project cash flows that economic development of fields becomes practical. A possible alternative development scenario is to use horizontal wells to increase the well rates or even combine the two technologies. This is illustrated in Figure 41 where the large number of closely spaced propped TSO hydraulic fracturing

treatments have to be placed along a 1200m horizontal well. This type of completion has been used on a wide scale for the oil bearing chalk fields in the North Sea. Such arrangement also improves the waterflood front between injectors and producers, making it more linear and ensuring a better oil sweep efficiency.

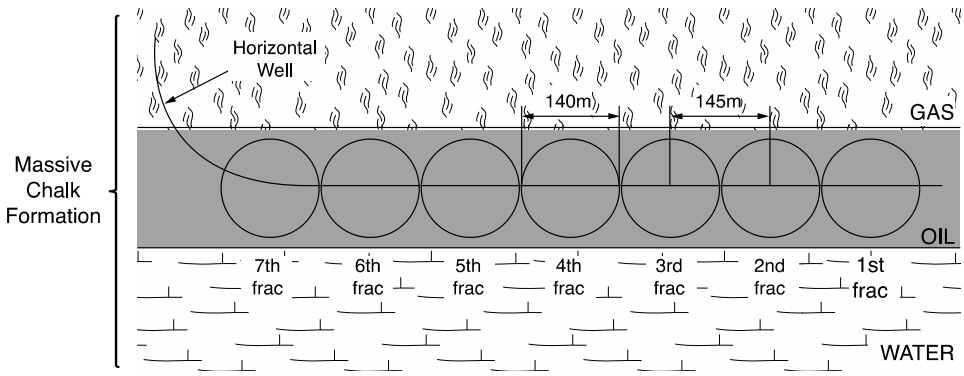


Figure 41 Completion employing combined horizontal well and multiple fracturing technologies

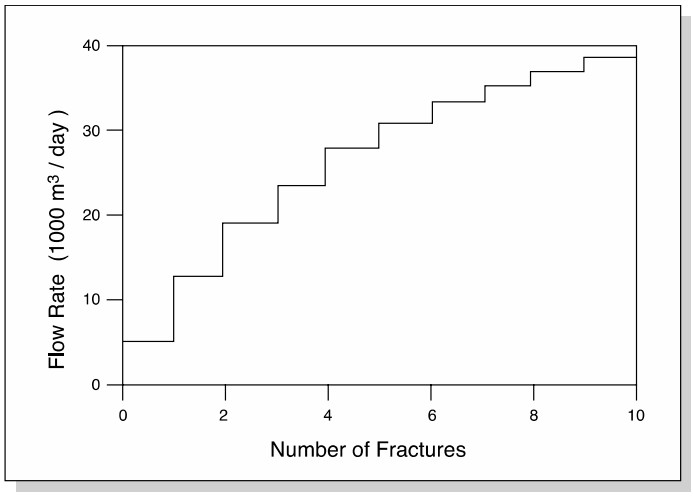


Figure 42 Example of increased gas production achieved from a multiply fractured horizontal well in a low permeability formation

Figure 42 shows that the potential production rate increases as the number of hydraulic fractures increases, but that the rate of increase for each extra fracture is continually decreasing because they interfere with each other in the terms of the reservoir inflow as well as frictional pressure losses along the length of the horizontal well becoming progressively more important.

(5) Fines migration: is triggered by high flow velocities due to radial inflow into a perforated well. The flow velocities are reduced, and this form of formation damage avoided, by the linear flow associated with a fractured well. Similarly, sources of formation damage which are caused by pressure reductions may be avoided since the improved well inflow will increase the flowing bottom hole pressures (at a given production rate).

14. FRACTURING UNCONVENTIONAL, SHALE GAS AND OIL RESERVOIRS

Unconventional, i.e. shale, oil and gas reserves have been unlocked in the past few decades by the use of advanced hydraulic fracturing technology. To-date hundreds of thousands of horizontal wells have been drilled and completed with multiple fractures in unconventional, shale gas reservoirs.

Such reservoirs with nano-Darcy permeabilities are unable to produce economically otherwise. So much so that the Stimulated Rock Volume (SRV) of such wells, contained between the fractures, is likely the only volume contributing to production. The flow regime in such wells remains transient during production as it may take years or decades for the pressure to become steady-state with such low permeability.

The wells are somewhat short-lived, ceasing most of production in a few years due to the depletion of the SRV and/or damage to the fracture conductivity as the plastic shale creeps into the fracture.

The objective is to drill a long horizontal well, some few thousand feet long, parallel to the minimum stress direction. The pay zone can be cased and cemented (most often) or left openhole, equipped with a liner and either external casing packers or swellable packers at regular intervals. Then long and narrow fractures, perpendicular to the wellbore, are created every 30-100 ft or so. Slickwater is most often used since the fluid leak off is not high in such low permeability reservoirs (though natural fracture networks, if present, can [hopefully] get reactivated and affect the leak off). It is pumped at very high rates and injection pressures. Low proppant concentration (typically of the smallest sand, 70/140 mesh size or smaller) is sufficient. Multiple wells can also be stimulated together to save costs.

A well thus may have tens or hundreds of fractures crossing the wellbore at right angle at either regular or irregular, formation property-defined intervals. Creating all the fractures in one go is impossible, so they are grouped into stages (a few fractures per stage) and each stage is done sequentially, starting from the toe. Typically, 200k-300k lb of proppant per stage is used, with 20-30 stages per well.

In **cased and cemented** completions, the fracture initiation points can be either defined by perforating a short interval (a 'perforation cluster' 1-2 feet long) or having a pre-installed, cemented casing sleeve opened. In each stage, the perforation clusters are created or the sleeve is opened, followed by construction of the fractures, after which the stage is temporarily isolated and the routine is repeated for the next stage. When perforation clusters are used, this is called the 'plug and perforate' (PnP) method and it's most common. *Optionally, coiled tubing can also be used to hydrajet the perforation clusters and monitor the fracturing, while the fluid and slurry are pumped down the CT-casing annulus. The problem is the CT can get stuck if some of the proppant is left in hole.*

In **openhole, liner completions with spaced packers** the pre-installed casing sleeves can be opened in every next stage before the stage fracturing begins.

15. RECOMMENDED READING

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CHAPTER 10: SAND CONTROL

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LEARNING OBJECTIVES

(All Examinable)

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

- Describe the impact of an incorrect decision of whether or not to allow for the installation of sand control during the original completion design.
- Explain why it is difficult to definitively predict a sand production problem in a newly developed field.
- State measures taken to modify completion/surface facilities to "live with" sand production.
- Construct a methodology for predicting sand failure.
- Discuss various rock mechanical measurements that may help with this prediction.
- Describe and contrast the various sand control options (none, types of bare screen, internal and external gravel packs, fracpacks).
- Identify the key elements of liner/screen design.
- Discuss openhole completions design and drill-in fluid selection.
- Discuss the characteristics and functions of the fluid and gravel used in a gravel pack.
- Describe the gravel selection process.
- Explain what influences the pressure drops associated with flow through a gravel-packed completion.
- Describe the fluid and gravel placement operation and how its success can be evaluated.

1. INTRODUCTION

Sand production from (relatively) unconsolidated reservoirs is a frequently encountered, costly operational problem which has a significant impact on well operations and the economics of oil and gas production. It is usually associated with shallow formations; but has also been encountered at depths greater than 4,000 m. Other types of unstable formations show similar production problems. Solids or even large "chunks" of formation can break away and enter the wellbore; while soft chalks, shales, siltstones and rubble zones can all flow "particles" of varying sizes or undergo plastic formation failure due to the stresses imposed by well production. Production of fines (very small particles that can migrate in the pore space) is common and is normally not a big problem. It's once the proportion of the larger, load bearing solids in the produced sand increases this is called 'sand production' and has to be dealt with. There are case-by-case based criteria on how much sand production a system can tolerate. Some 30% of wells in sandstone reservoirs, and a smaller proportion in carbonate reservoirs show sand production problems.

Identification of which wells require a sand control completion, especially during the (initial) phase of a new field development, is a **difficult,** but **key** decision, because:

1. **The incorrect omission of a sand control completion** results in it not being possible to continuously produce the well due to the production of sand particles from the reservoir leading to:
   - Flow being prevented up the tubing due to the formation of sand "bridges".
   - Sand particles falling into the bottomhole and, eventually, covering the perforations with a loss of production.
   - Production restrictions in deviated and horizontal wells due to sand dunes being deposited in the horizontal section and the heel where there are significant changes in the deviation angle.
   - Damage to the well's integrity with casing/liner collapse occurring due to loss of lateral support in the areas where sand production has occurred.
   - Downhole equipment, e.g. the Subsurface Safety Valve, stick due to solid particles preventing the proper working of their mechanism's moving parts.
   - Artificial lift equipment, particularly pumps, being damaged by erosion or becoming stuck, halting production.
   - Erosion (sand blasting of holes), particularly in surface pipework where pressures are lowest and velocities are highest, can lead to them being 'cut-out' (eroded) followed by pollution associated with an oil/gas spill and/or loss of well control.
   - The produced sand having to be removed from the well's production flowlines and surface facilities (usually the separators). There may be huge quantities, e.g. tens of tons a day from a medium-size field. Let alone this oil-covered sand must be disposed of in an environmentally acceptable manner.

   ➢ *Feel free to select a well completion example in Chapter 1 tutorials and discuss how it can be damaged due to sand production.*

2. However, **the unnecessary inclusion of sand control measures** results in:
   - Extra completion cost (higher initial investment) due to the need to install extra completion equipment.

- Loss of future workover flexibility due to the difficulties in removing the sand control completion during the well workover.
- Reduced well production due to installed sand control completions (completion skin S_c >0).
- Increased artificial lift costs due to a reduced well Productivity Index (PI).
- Loss of reserves due to this reduction in PI. This is because a well should be abandoned once the well's Minimum Economic Production Rate *(when the well's operating expenses are equal to the net income)* has been reached; and the wells with lower PI either produce less or require additional investment e.g. artificial lift to reach the target rate (hence higher expenses). Either way, this is likely to result in earlier-than-optimal abandonment leading to under-recovery of reserves.

The technology developed by the industry for efficient sand exclusion along with a more detailed discussion of the above will be covered in the following sections.

2. SAND PRODUCTION

The completion zone is usually heterogeneous, displaying a wide range of mechanical and chemical properties. Drilling and perforating the well will alter the natural formation stresses. Strong formations will accommodate and redistribute this stress; while the formation strength may be exceeded in weaker sands. A further complication is that the increased stress created by (the frictional forces of) fluid flow towards the wellbore, as well as pore pressure changes due to draw down and depletion, all contribute to the formation strength being exceeded. Increase in water saturation will also affect the process by altering the capillary forces and possibly disturbing the water-sensitive clays that cement some of the matrix grains.

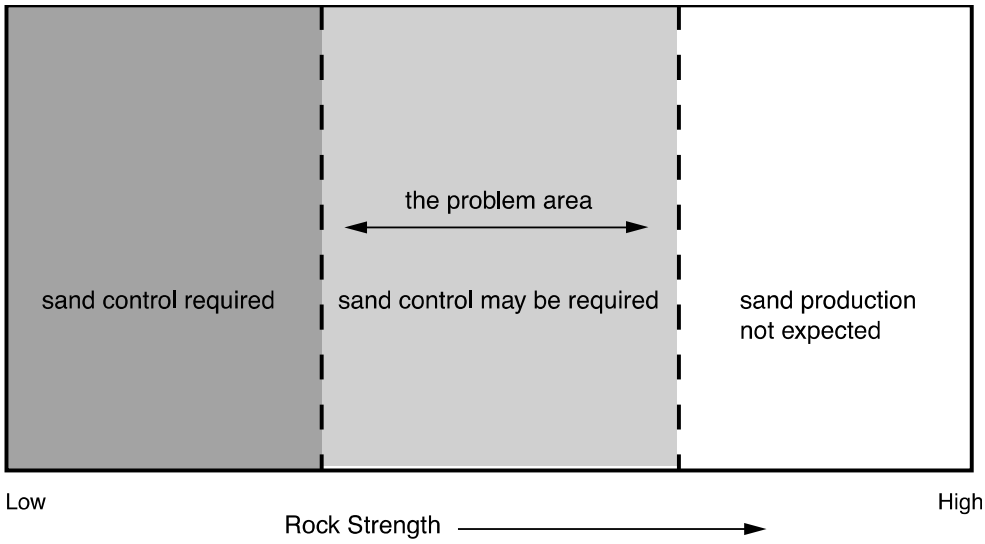

Figure 1 When will a sand control completion be required?

2.1 "Continuous" Sand Production

Sand production is a two-stage process with **sand production only being observed once *both* the following processes have occurred**:

1. Formation failure, leading to individual sand grains (that were previously part of the load bearing matrix) being formed *(a rock mechanical criterion).*

2. The well production rates are sufficient to transport (drag) these sand grains into the wellbore *(a fluid mechanical criterion).*

Very soft formations will exhibit sand failure problems right away, e.g. when the newly drilled hole collapses during exploration drilling. Such "sloughing" sands cause great difficulties during well completion operations. Stronger formations may show sand production after a period of time due to (i) reservoir pressure depletion increasing the effective stress acting on the formation, (ii) increased fluid velocities, (iii) water production (Figure 2$_{right}$), etc.

The forces, causing sand production, increase with a rising well production rate, implying that there can be a critical flow rate or drawdown below which sand production does not occur. Reducing the production rate is a field proven method to temporarily stop a well from producing sand (Figure 2$_{left}$).

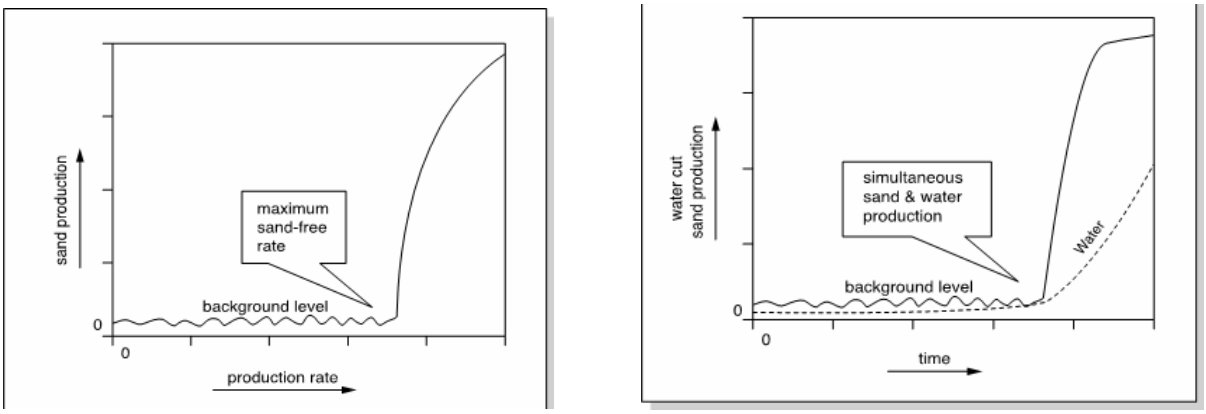

Figure 2 Field observations show that continuous sand production starts later in the well life, often when water production starts or at high production rates. A threshold drawdown or production rate can also trigger sand production earlier.

Sand production can be created by poor completion practices. For example, poor perforating practices such as insufficient and/or plugged perforations lead to an increased drawdown, increased local fluid velocities around the few open perforations and the potential for water coning. These are all factors that lead to an increased level of sand production. In many such cases reperforating or fracturing the well to decrease the flowrate-per-unit-area (and hence drawdown) solves the sand production problem. If such solutions are effective, they should be preferred.

In other words, remedial intervention options to mitigate this problem completion are:

- Re-perforate the completion interval *(minimise the well's producing drawdown).*
- Reduce the production rate *(often a temporary solution).*
- A propped hydraulic fracture *(decreases the local fluid velocities).*

Generally, selecting the right completion in the first place is often the best way to avoid sand production. E.g. in addition to the above the other options like perforating/fracturing only into strong formations (provided the weak formations communicate with the strong ones or are connected via the hydraulic fracture); or oriented, vertical perforation (as explained in Chapter 6) are found effective.

2.2 "Clean-Up" Sand

Continuous sand production has to be distinguished from temporary, "Clean-up" sand production. This refers to the relatively minor amounts of sand that are produced from a new well during the first few days of production. This form of sand production is attributed to the shock wave produced during the perforating process (partially) de-consolidating the formation. Local rock failure then alters the shape of the initial perforation tunnel so that it changes to a more stable shape (Figure 3_{left}). Multiple individual perforations may merge together to form a cavity in extreme cases (Figure 3_{right}). "Cavity" formation can lead to casing failure (collapse) caused by the formation exerting unbalanced stresses on the casing.

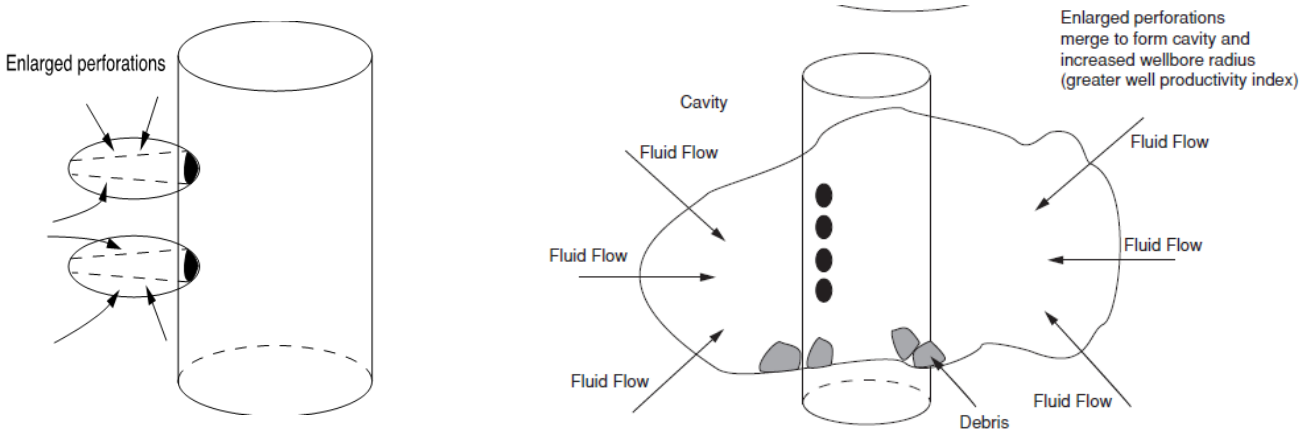

Figure 3 Sand production enlarges perforations and may form cavities in friable formations

"Clean-Up", or transient, sand production is observed in all types of production wells (Figure 4); a new burst of sand production being observed each time the well's production is increased. This is attributed to mobilisation of previously failed sand that was not produced into the well by the previous (lower) production rate. The production rate of sand producing wells should be increased (a.k.a. 'beaned up' by gradually increasing the surface choke's bean size) slowly, preferably over a period of hours or even days. Well production conditions should be maintained as constant as possible to encourage stable arch formation around perforation tunnels. *This also means that in wells with oscillating production (rapidly changing rate e.g. due to severe slugging or rod pumping) the sand production can be very high, and so the production rate stabilisation, if possible, should be a priority.*

The key point about transient sand production is that it is temporary. It decreases to a low level after a certain period of time when the well is kept on production at a constant rate. The time required for stabilisation to occur is dependent on the type of well – gas wells responding more quickly than light oil wells; which, in turn, respond faster than heavy oil wells (Figure 4).

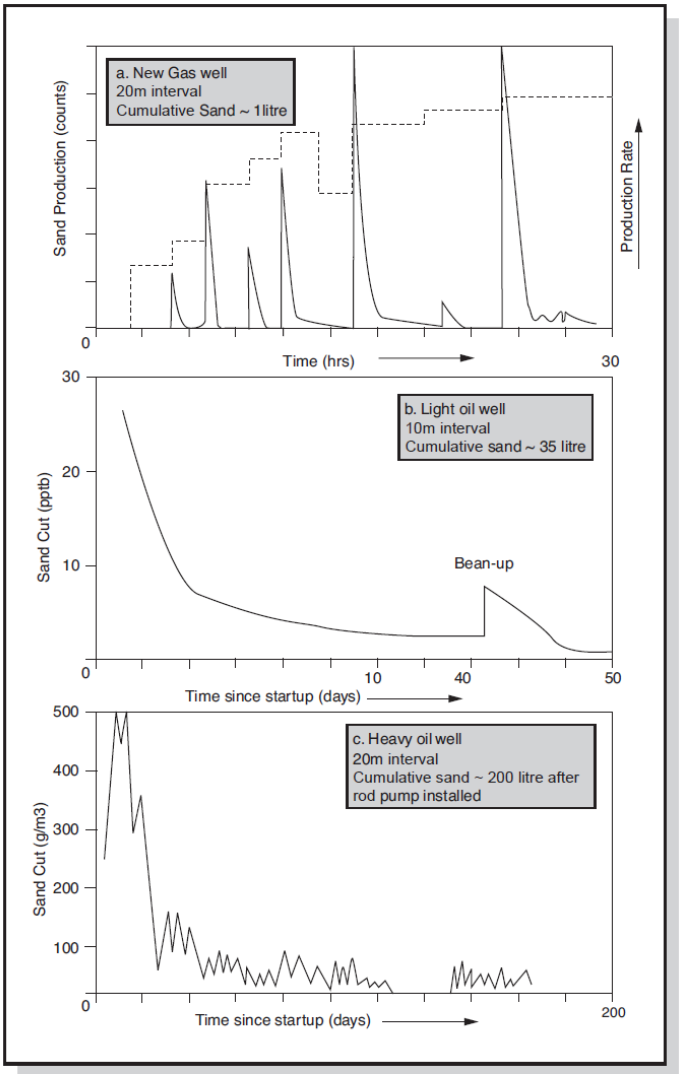

Figure 4 Field data showing transient sand production in different types of wells.

2.3 Sand Cementation

Sandstone formations were originally laid down as a bed of loose sand grains e.g. at the bottom of a river, or as a beach at the sea shore. Over geological time these individual, loose grains became consolidated, or cemented, together – a process which resists sand production. These individual sand grains, which make up the bulk of the sandstone formation, are bonded together by clay, quartz, calcite or other minerals that precipitate on the surface of the grains. The "overburden load" (or weight of all the sediments above the formation) is resisted by the strength of the individual sand grains, the pressure of the fluids within the pore spaces and the strength imparted to the consolidated formation by these intergranular cements (Figure 5).

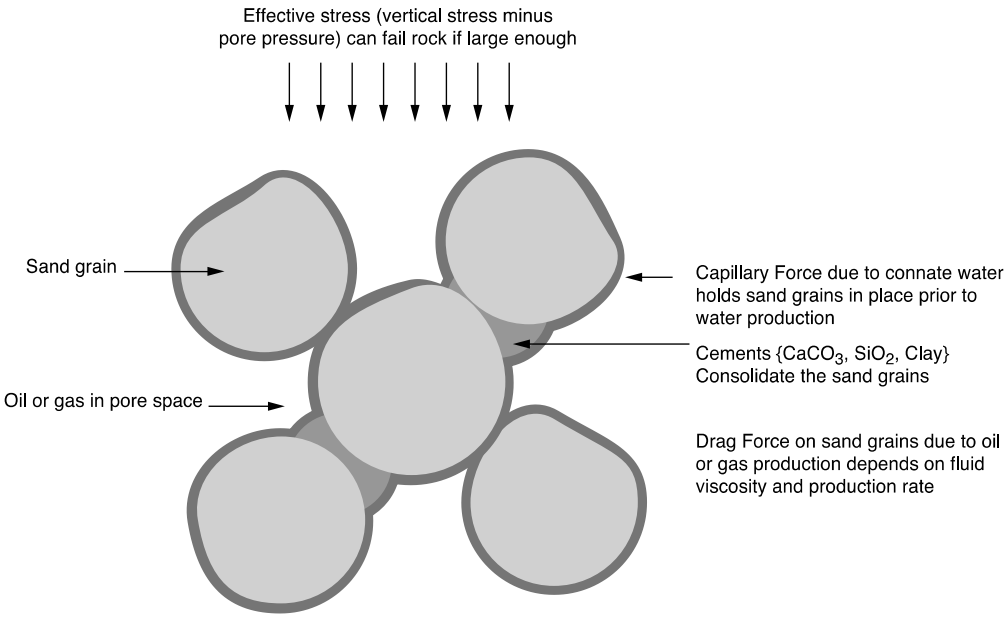

Figure 5 Factors affecting sand production.

As mentioned, sand production relates to the production of load bearing formation solids while "fines" production involves the production of mobile, very small, solids which are not part of the mechanical structure of the formation. These small clay, feldspar or silica particles: the fines, pass through the pore throats. Attempting to stop production of the fines will result in them plugging the pores and creating extensive formation damage and drastically reducing the well's production. The completion should be designed to allow them to pass into the well with the produced fluids, so that they do not cause permeability damage in the near-wellbore area.

Cementation (of matrix grains) of a potential reservoir usually occurs in geological past, prior to the arrival of the hydrocarbons. It often occurs by precipitation of minerals from the water phase within the pore space between the sand grains. Local cementation also occurs at the grain-to-grain contact due to a pressure dissolution and precipitation cycle. This is due to the high overburden load generated by the weight of all the shallower formations acting on the small contact area of the individual sand grains. Quartz, a form of silica, increases in solubility at the high pressures exerted by this point-to-point loading of the sand grains. The water surrounding the active sites becomes over-saturated, compared to the unloaded part of the sand grain, and (re-)precipitates. As time passes, the contact points of the grains become flatter, spreading the load over a wider area of total contact i.e. the local point-loading decreases. Eventually, the increased grain contact area is sufficient to withstand the overburden and the form of the individual sand grains stabilises. This pressure driven "dissolution and precipitation" process at the grain contact is only one method of sand grained cementation.
Additional amounts of the same or different cements may be precipitated from aqueous, hydro-thermal fluids flowing through the formation over geological times. Mineral cements are precipitated as the water in the pore space comes to equilibrium with the local conditions of the temperature, pressure and mineral composition. Quartz overgrowth around calcium cementation or clay development at the grain boundaries is a sign of such secondary cementation.

Formations may not consolidate for a number of reasons, such as reduced compaction loading caused by shallow burial or the presence of large, load supporting arches (grabens) above the reservoir, etc. Faults may also block these stresses. Mineral solution or precipitation from the aqueous phase stops as soon as the structure is filled with hydrocarbons, resulting in high porosity formations with poor inter-grain bonding. High pore pressure (geo-pressures) allow the pore fluid to carry a greater fraction of the overburden load, reducing the compaction loading. Other types of chemical reactions, such as ground water leaching of the matrix grains, dolomitization, etc. may modify the cement or the size of the sand grain after it has been formed.

2.4 When is Sand Production a Problem?

The well's sand production tendency may change during the lifetime of the well. In particular, what was a negligible or marginal problem may become much more severe later in field life due to:

A) Water Production. This results in:

- Higher drawdowns (and thus increased rock stress) and high liquid rates (and thus higher drag forces) to keep the target oil production rate while co-producing this water.
- Loss of capillary pressure between the sand grains. This pressure helps prevent mobilisation of the sand grains when dry oil is being produced by the well.
- Increased water saturation can reduce the strength of some water-sensitive clays cementing the formation.

B) Production Plans that call for maintaining the net oil production. This results in a continually increasing gross fluid production as the water cut increases, as mentioned above. Or in a continually increasing drawdown if the formation damage increases. Also, if the completion becomes damaged (e.g. perforations plugged or scaled, sandscreen plugged etc.) there will be higher production from the less damaged zones.

C) Reservoir Pressure Depletion increases the effective stress on the near wellbore formation, as was explained in Chapter 9, which equals the maximum (overburden) effective rock stress σ'_v:

$$\sigma'_v = \sigma_v - \alpha P_p$$

Where σ_v is the overburden weight, α is the Biot's poro-elastic constant (typically 0.7-1), and P_p is the pore pressure.

A decision still has to be made whether to control sand production (the safe option) or live with it and risk the (later) consequences of sand production.

2.5 The Consequences of Sand Production

Sand production leads to numerous technical, environmental, operational and economic consequences (Table 1). Some of them were already mentioned earlier. The effects of sand on production operations and the potential safety, financial and environmental consequences will influence the maximum, acceptable level of sand production. The operationally acceptable level of sand production will vary with well location, production facility design and local conditions.

Many of the deposition processes of unconsolidated formations result in a heterogeneous, layered formation. The flow rate that will produce sand in one interval may give sand-free production from another layer in the same formation only a short distance (e.g. 1 ft) away. The apparent formation strength will also be affected by the changes in the reservoir pressure and water saturation over the life of the field.

Similarly, a sand control process that stops the production of large sand grains may not work efficiently for smaller sand grains. The chosen sand control completion design must normally be suitable for all completion intervals. This is true when it is impractical to install a different sand control measure e.g. for a thin, weak layer within a larger pay zone. Otherwise, when there are several large pay zones, multi-zone completions e.g. multi-zone gravel packs can be an option.

Selective perforation of the stronger sands can avoid the need for installation of sand control in formations where only a small fraction of the zone completion interval presents a risk of sand production. However, it is important to realise that there is a high risk that the reserves associated with these unperforated zones may not be produced.
The answer is to determine which sections of the pay zone will fail.

Location	Problem	Effect
Completion interval	Wellbore fill from bottom	• Restricted access to production interval
	Cavity formation	• Reduced work over success since zonal isolation no longer practical • Increased well productivity Index
	Casing buckling	• Loss of full diameter access to completion interval • Casing failure in extreme case
Tubing	Sand bridge	• Well production halted • Loss of reserves
Subsurface equipment	Sand deposition in tubing and accessories	• Surface controlled, sub surface safety valve (SSSV) not operating - a safety issue • Difficult Wireline operations
	Erosion	• Equipment replacement and failure
Surface installations	Sand accumulation	• Control equipment malfunction • Reduction in separator residence time • Unscheduled shut-downs/deferred production • Sand separation from hydrocarbons • Sand disposal
	Erosion	• Failed equipment replacement • Oil/gas spill (environmental/safety issue)

Table 1 The Consequences of high levels of Sand Production.

3. THE COST OF SAND CONTROL

It is clear that the consequences of sand production can be severe. On the other hand, installing a sand control completion not only results in the extra cost of the completion hardware, but also includes the potential for any reduction in the expected well reserves (this was explained earlier). So it must be included only where actually needed.

Figure 6 summarises the example data generated during a test to evaluate the well productivity during the various stages of installing an internal (i.e. cased-hole) gravel pack in a newly drilled well. The well Productivity Index was measured after:

- Perforating and cleaning up the newly drilled well.
- Killing the well and returning it to production
- Killing the well and installing an internal gravel pack
- Six months of production

68% of the well productivity was lost after killing the well, a figure which increased to 98% when the internal gravel pack was installed. The final well productivity after a six month clean up period was only 14% of the value for the perforated completion. Such high impairment level in gravel packed wells does happen, but not commonly.

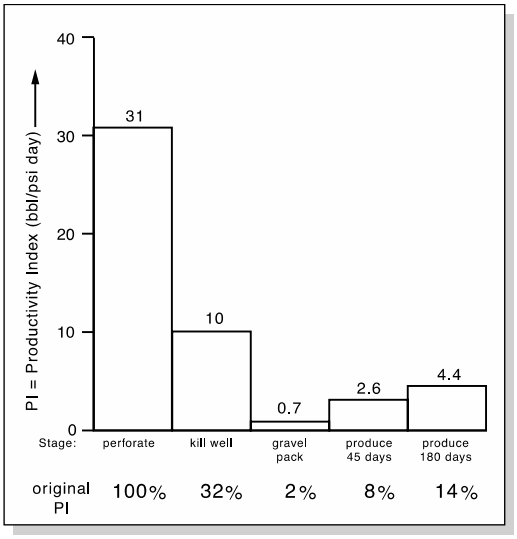

Figure 6 Changes in well productivity when installing an internal gravel pack.

Completion Type	Well Productivity Index (bopd/psi)	Number of Wells required to reach Field Development Plateau Rate	Required Gas lift (MM scf/d) Water Cut (%)			Oil Recovery at Field Abandonment
			20%	50%	80%	
Internal Gravel Pack	5	60	0	5	15	Lowest
External Gravel Pack	15	55	0	0	5	↓
Perforated	30	30	0	0	5	Highest

Table 2 Impact of completion efficiency on the field development scenario.

The typical levels of completion efficiency associated with the different types of sand control completion vary greatly. Examples of the impact of well productivity when applied to a Field Development Plan are summarised in Table 2 where the installation of a sand control completion:

- Increases the number of development wells.
- Increases the capital costs per well.
- Requires earlier installation of artificial lift.
- Results in higher abandonment pressures and reduced oil recovery.

4. LIVING WITH SAND

Produced Fluid	Production	Allowable Sand Level
Gas	< 50 M scf/d > 50 M scf/d	1 lb / MM scf 0.5 lb / MM scf
Light Crude Oil	< 5000 bopd 5000-15000 bopd >15000 bopd	30 lb / 1000 bbl* 10 lb / 1000 bbl* 5 lb /1 000 bbl* * reduced by 50% for high GOR
Heavy Crude Oil		200 lb / 1000 bbl or higher
Extra Heavy Crude Oil Tar Sand		0.1 - 5% vol. sand fraction

Table 3 Typical Average Allowable Sand Production Levels *(the individual levels for a particular field may vary greatly!)*

It can be seen that the allowable sand content is very dependent on the produced fluid's velocity (production rate), viscosity and gas fraction. Erosive forces will be greatest at the surface where pressures are lowest and the velocities highest, hence for such conditions the allowable sand concentration is lower.

A sand management system must be installed if the "Living-with-Sand-Production" option is chosen. Changes made to the production system (Figure 7) to make it more tolerant to the produced sand volumes may include:

1. A wellhead desander (a hydrocyclone) and a batch operated sand accumulator to remove the sand prior to the hard-faced choke.

2. A "sand tolerant" artificial lift method, such as gas lift or a progressing cavity pump. The sand-containing fluid no longer comes into contact with moving valves and/or rapidly rotating parts that can be damaged, as occurs in e.g. rod or electric submersible pumps.

3. Designing surface flow line so that large changes in velocity and direction do not occur e.g. removing 90º pipe bends.

4. Regularly monitoring surface flow line's wall thickness and the build-up of sand in surface vessels (Figure 8) with non-intrusive and/or intrusive sensors (*more on this will be presented below*).

5. Measuring the volumes of sand produced and setting up a sand accounting system.

6. Installing high-pressure water jets at the bottom of separators. The high velocity water stream fluidises the sand and transports it to a collection and disposal facility. The adhering oil may be removed by vigorous agitation of the sand grains with water to allow easier subsequent on-site cleaning. Alternatively, this sand may be transported off-site for expert clean-up and/or safe disposal elsewhere.

7. Increasing the well production (by opening the well choke) in a number of small steps (slow bean up), allowing the well to stabilise between each step and avoiding cycling the downhole pressure (such as occurs with a rod pump) if possible.

8. Ensuring the fluid velocities are sufficient to transport the produced sand grains to an operationally convenient collection point at the surface. The sand particles will concentrate at points where the settling velocity, given by Stokes' law, is greater than the (upward) flow velocity. This critical flow velocity increases with increasing particle size and decreases with increasing fluid viscosity (Figure 9).

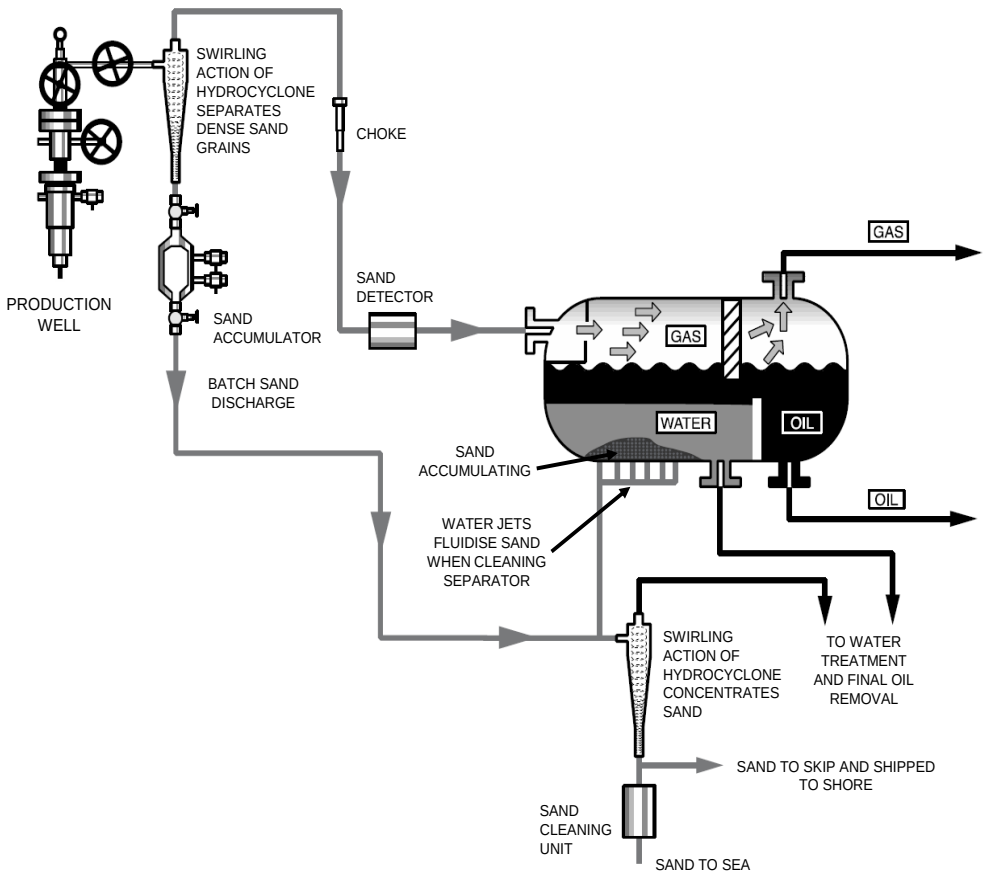

Figure 7 An example "living with sand" installation

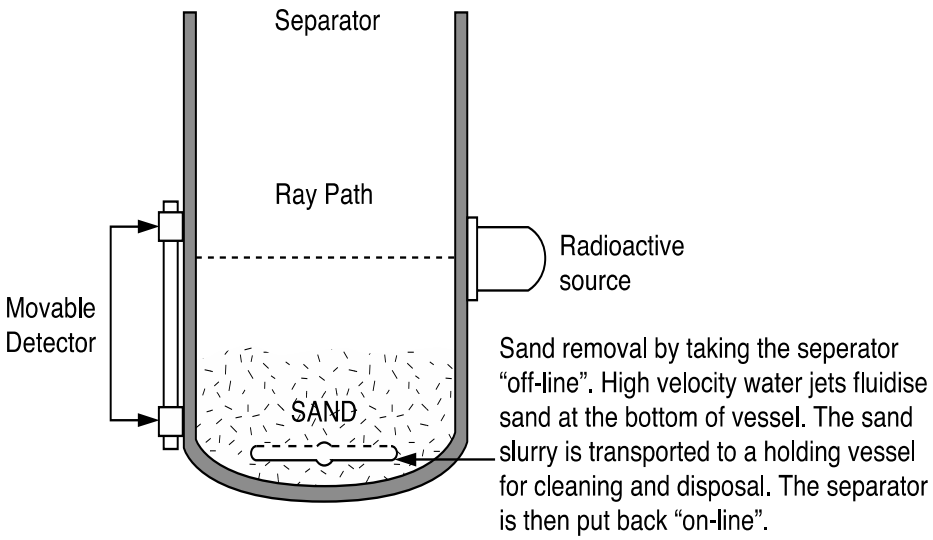

Figure 8 Monitoring sand level in a separator through increased x-ray absorption.

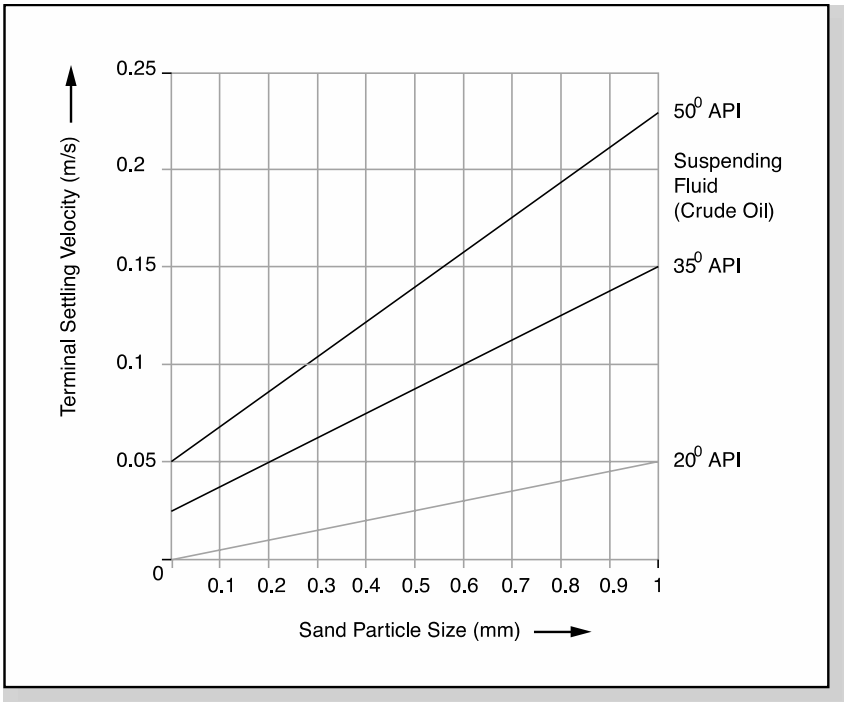

Figure 9 Terminal settling velocity of sand particles in different crude oils.

Some extreme sand production cases (e.g. Cold Heavy Oil Production with Sand CHOPS technique – see Chapter 1) may require additional sand management solutions.

4.1 Monitoring of Sand Production

The various techniques used for monitoring sand production are summarized in Table 4. This table indicates the measurement principle employed, its key points and the associated drawbacks.

MONITORING OF SAND PRODUCTION			
Technique	**Principle**	**Measurement**	**Drawbacks**
Wellhead Sampling	Centrifuge wellhead produced oil sample	Simple	• Not continuous; • Non-representative • Manual
In-Line Sand Trap	Sand settling into pots located in flow lines	Simple	• Estimates sand at flowline production rate • Manual
Erosion Probes	Hollow probe inserted into flowline. Penetration of probe wall by sand erosion activates alarm since flow line pressure appears inside probe	Erosion measurement depends on sand production rate, flow rate, type of produced fluids, probe position etc.	• Alarm system only. • Installed where severe erosion expected
Sonic Detectors	Acoustic noise of solids impact measured by a piezo electric crystal mounted on a solid probe installed in flowline	Detects mass rate of sand produced. Larger particles make bigger impact	• Interference from flow noise e.g. gas bubbles and small solid particles (fines) • No erosion measurement
Flowline Erosion	Measure wall thickness by ultra Sonic / x-ray techniques at regular intervals	Erosion detection only	• Not on-line • Not continuous • Expensive

Table 4 Monitoring of sand production.

5. PREDICTION OF SAND FAILURE

A number of techniques can be employed when deciding whether to install sand control completion. These include:

- Field experience.
- Petrophysical log and core analysis.
- Wellsite rock strength estimation.
- Rock mechanical measurements and calculations.

5.1 Field Experience

The production history of wells producing from the same formation in the field where the new well is planned is often the best guide as to whether to install a sand control completion. Similarly, sand production data for wells producing from the same formation in a nearby field with a similar geological history can also be used to guide the decision on whether a sand control completion is required.

5.2 Petrophysical Analysis

Correlations based on laboratory measurements on core material from the same geological section are typically in the form of a trend line drawn through a cloud of data points. This inexactness is due to the heterogeneity of the formation properties and the errors in the measurements. Some general comments can be made despite this:

- The sonic travel time (Δt, μs/ft) or, more correctly, the sonic slowness, is related to the porosity, i.e. the higher the porosity, the longer the travel time (Figure 10_{Right})
- The rock strength (as measured by an unconfined compressive strength test or thick wall cylinder

collapse test – *explained below*) is inversely related to porosity (Figure 10_{Left}), i.e. the lower the porosity, the greater the rock strength.

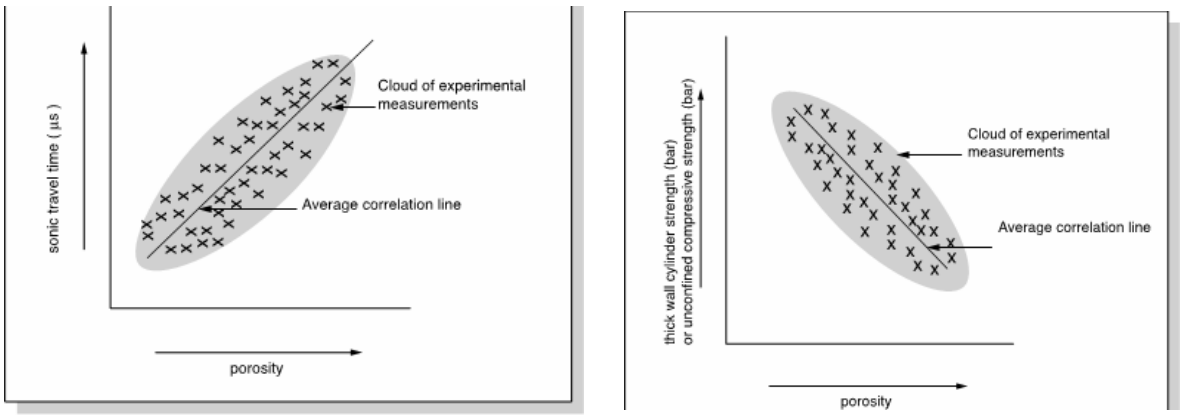

Figure 10 Sonic travel time and thick wall cylinder strength are both related to porosity

5.3 On-Site Rock Strength Measurement and Estimation

The simplest on-site strength test of a formation core approach is that "a sand problem is expected if the core is friable (i.e. finger nail makes a groove) or even weaker". Table 5 extends this approach. It relates the rock classification to simple strength observations made on the core, to the approximate sonic travel time and to the core recovery ('*core recovery' is the fraction of the core retrieved to surface intact*).

ON-SITE ROCK STRENGTH ESTIMATION				
Uniaxial Compressive Strength (psi)	**Rock Classification**	**Core Observation**	**Approx. Sonic Travel Time(µs/ft)**	**Core Recovery**
0	Quicksand	Hole Slumps	>150	zero
< 1000	Unconsolidated	No apparent cement between sand grains	> 145	Sleeve[1] (poor[3]) Conv.[2] (zero)
1000 - 2500	Semi-Consolidated	Easily Crushed	> 130	Sleeve[1] (good) Conv.[2] (poor[3])
2500 - 3500	Friable	Rub-off Grains	105 - 130	Conv.[2] (good)
3500 - 7500	Consolidated	Crushable with forceps	75 - 105	excellent
7500 - 12000	Moderate Hard	Cannot Crush	65 - 75	excellent
12000 - 20000	Hard	Cannot Crush	<65	excellent

[1] sleeve refers to use of rubber sleeve core barrel to support cored material
[2] conv. refers to use of conventional steel core barrel (no support for core)
[3] great care required during coring - prevent core barrel jamming, avoid excessive mud velocities, etc.

Table 5 On-Site rock strength estimation.

5.4 Laboratory Measurements

5.4.1 UNCONFINED COMPRESSIVE STRENGTH

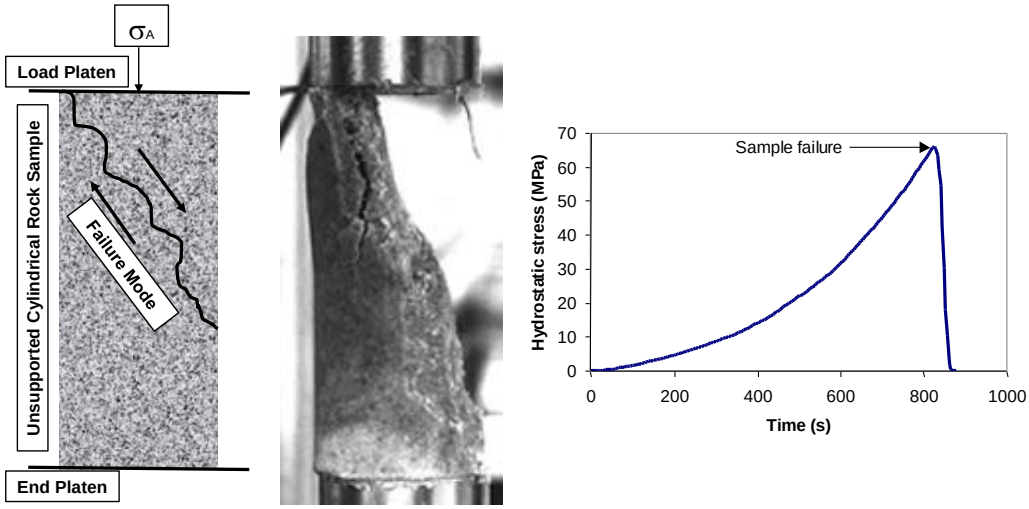

Figure 11 Unconfined Compressive Strength measurement

An unsupported cylinder of rock with a 2:1 length to diameter ratio and parallel ends is loaded axially at a steady rate until compressive failure (a diagonal fracture) occurs at the maximum stress (Figure 11). This value of the Unconfined, or Uniaxial, Compressive Strength (UCS or σ_{ucs}) can be correlated with the porosity (Figure 12) when the samples are taken from the same formation. UCS rock classification is presented in Table 5.

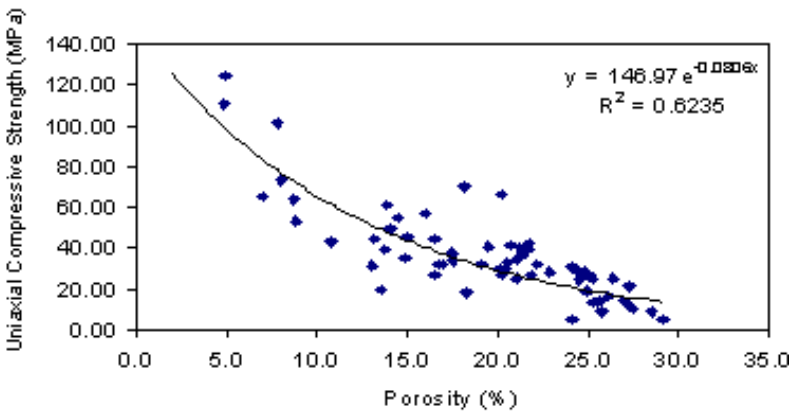

Figure 12 Unconfined Compressive Strength as a Function of Formation Porosity (a field-specific example)

5.4.2 THICK WALL CYLINDER COLLAPSE STRENGTH

The Thick Walled Cylinder (TWC) test that replicates the geometry of perforation failure (Figure 13) is often more representative than UCS, but also more complex/expensive and hence less available. The hollow, thick walled cylinder is created by drilling a narrow hole in the middle of a rock cylinder similar to that employed in the UCS test (Figure 11). The rock cylinder is enclosed in a rubber sleeve and installed between two end caps. The hole in the centre of the cylinder is maintained at atmospheric pressure while the same stress is applied to the end caps and the outside of the sleeve. The stress at which the cylinder collapses (or implodes) is the Thick Wall Cylinder Collapse Strength (σ_{twc}).

The perforation hole shows compressive failure (Figure 13Upper Right). The frictional strength characteristics of the rock have a major impact on the TWC strength. They depend on the grain size distribution, porosity and degree of roundness of the sand grains. These are all related to the depositional environment for a specific field. Sands with a low degree of sorting, and sub-angular grain geometrics, will, in general, exhibit higher strengths than sandstones composed of well-rounded, similar sized grains, for similar degrees of cementation.

Laboratory measurements, confirmed by field experience, have shown that INITIAL sand failure occurs when the near wellbore vertical effective stress at the perforation depth is approximately equal to the TWC strength. However, field experience has shown that this initial rock failure is followed by a stabilisation process (compare with Figure 4.) This initial decrease in level of sand production is often followed by continuous production of significant volumes of sand much later in the well's producing life.

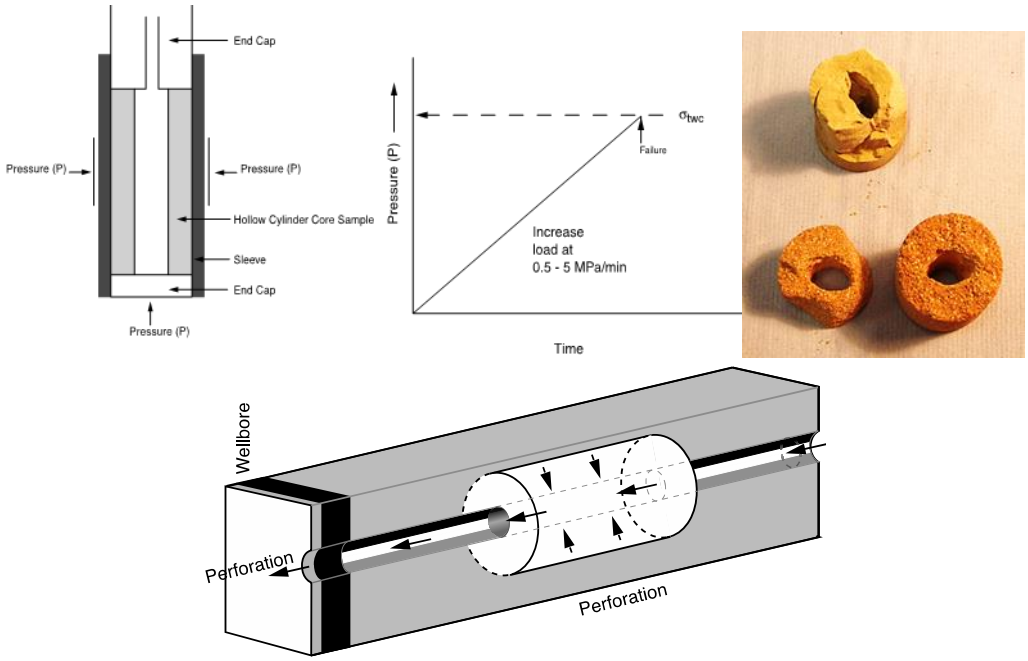

Figure 13 Crushing a (hollow) Thick Walled Cylinder simulates perforation failure.

5.2 Prediction of Downhole Rock Failure

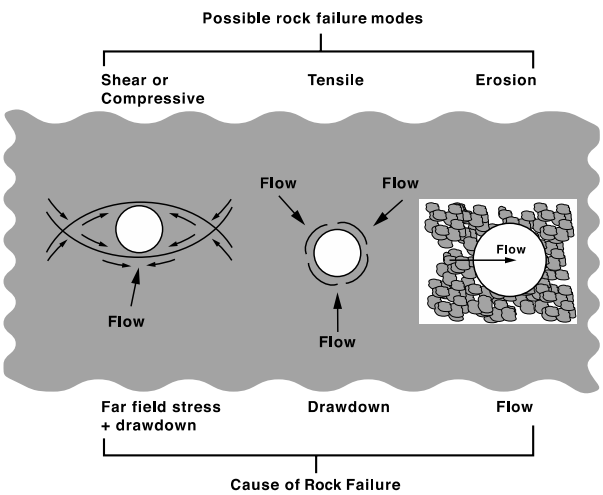

Figure 14 Possible rock failure modes for a producing borehole.

Full characterisation of the downhole properties of the rock is a complex subject. Similarly, a comprehensive description of the (sand) failure process taking place around a producing borehole is also complex. Not only must the stabilisation process be accounted for, but there are a number of possible rock failure modes (Figure 14). Analytical descriptions of these processes are available, but are (highly) conservative. They often represent the initial failure of the perforation tunnel, but do not capture the stabilisation processes that often delays the onset of unacceptable levels of sand production.

Development of a complete description of these processes requires the use of complex, numerical computer codes that include the:

- Availability of representative core material. (This is often not available: the weakest formations fail first and are the least likely to be recovered by coring process.)
- Carrying out of relevant laboratory rock strength measurements.
- Accurate forecasting of the producing well conditions (formation stresses and fluid flow velocities and phase cuts).
- Availability of a comprehensive model of the appropriate mode of rock failure.

The prediction of sand failure when long-term field history data is not available is a difficult process. However, the incentive for these studies: the high cost of unnecessary installation of sand control, is also considerable.

Use of a risk-based approach to determine the optimum timing of installing a sand control completion is sometimes the preferred route. Estimating the (Net Present Value or cost-benefit) economics of possible scenarios should include the field observation that installing a Remedial Sand Control completion in a well that has already undergone sand failure has a lower chance of success than the equivalent completion operation in a new well. The alternative, abandoning the existing completion and drilling a side-track to a new location followed by installation of a sand control completion can be more cost effective.

6. SAND EXCLUSION

Figure 15 illustrates the range of available sand control completions employing different types of sandscreens (except option (e)) with:

1. Gaps small enough so that some formation sand grains are unable to pass {Figure 15 (a) and (f)} or
2. A combination of a screen with wider gaps and "gravel" (coarse sand) particles {Figure 15 (b), (c), and (d)} placed in between the screen and the formation. The screen's larger gaps keep the "gravel" in place; while the gravel layer forms the filter to hold the formation sand in place.

As listed, most of the sand control options use a screen as the basis of the completion. First, the screen is inserted into the wellbore and the gravel, if required, is placed between the screen and the formation. Achieving a reasonable well Productivity Index requires that any drilling/completion fluid filter-cake present on the borehole or in the perforations wall must either be:

- Produced through the screen when the well is placed on production. This is often referred to as "well clean-up". OR

- Removed (e.g. by a stimulation treatment) before or after the sand control completion installation.

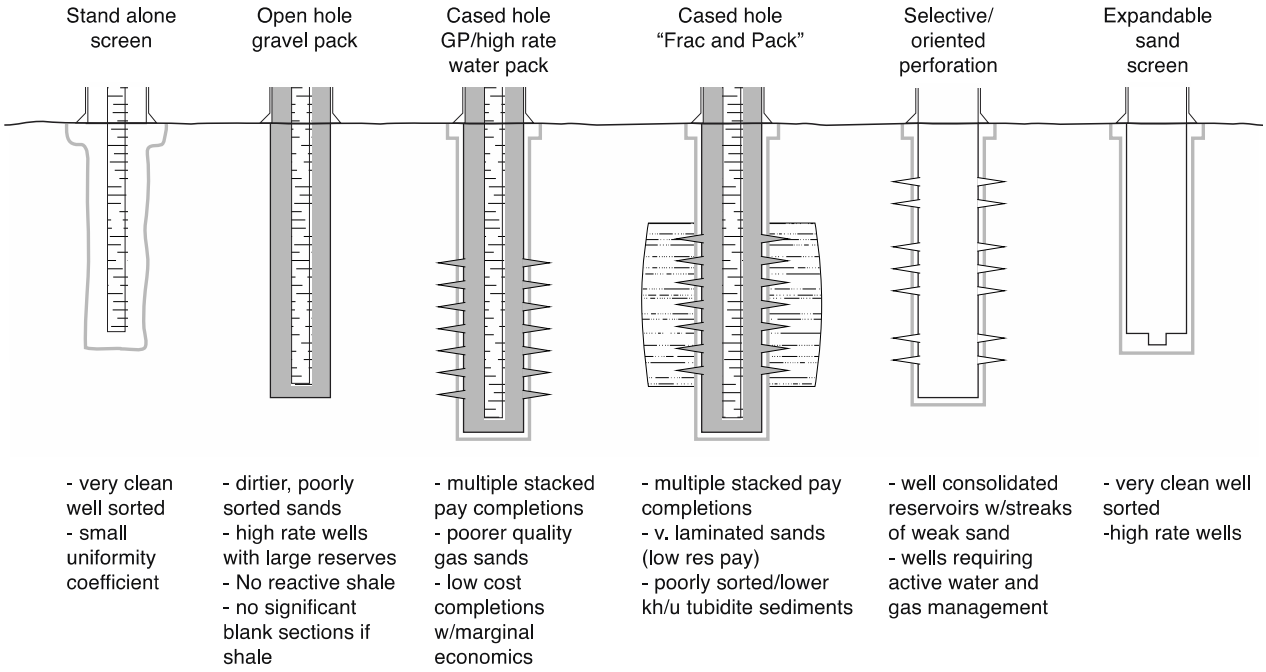

Figure 15 Sand control options.

The simplest sand control completion is the purely mechanical option of installing a "Stand-alone-Screen" {Figure 15 (a) and (f)}. The behaviour of the formation once the well is on production will depend on the formation's strength:

- **Strong formations:** the borehole wall remains intact and the gap between the liner and the screen remains empty, providing the mud cake has been removed.
- **Weak formations:** the borehole collapses and the original liner/borehole gap becomes filled with failed formation material.

6.1 Screen Types for Mechanical Sand Exclusion (*Stand-Alone-Screens SAS)*

Table 6 summarises the advantages and disadvantages of the various types of stand-alone sand screen completions.

ITEM	SLOTTED LINER (Mild Steel)	WIRE WRAPPED SCREEN (Stainless Steel)	PRE-PACKED SCREEN (either Resin Coated Sand or conventional sand)	WOVEN (a.k.a. premium or mesh) and/or EXPANDING SCREEN
Description	rectilinear slots / machined in pipe	wire wielded to longitudinal rods	consolidated gravel pack sand between two wire wrapped screens	One or more woven metal mesh filter layer(s)
Concept	reinforces; wellbore large sand grains bridge on slot	formation sand exclusion or gravel pack sand retention	resin consolidated gravel provides sand exclusion	various designs of one or more support and woven metal mesh filter layers
Material	mild steel	stainless steel on mild steel base pipe	stainless steel on mild steel base pipe	corrosion resistant alloys
Sand Exclusion	poor slot width: ≥ 0.012"	better than SL slot width: ≥ 0.006"	similar to gravel pack	similar to gravel pack
Works with Gravel Pack?	yes	yes	yes, not be necessary	yes, not be necessary
Flow Restriction	high	low, approx.10 times flow area of slotted liner	high, as for wire wrapped screen with gravel pack	lower than gravel pack, susceptible to plugging by mud and mud cake
Mechanical Resistance	good	poor, without base pipe susceptible to erosion.	fair: base pipe reinforces structure	fair: base pipe and/or support layers reinforces structure
Plugging Tendency	low (too wide to retain formation sand)	moderate allows fines production	high, fines + mud cake, also impairment by mud while running in hole.	high, fines + mud cake, also impairment by mud while running in hole.
Cost	cheapest	2-3 x slotted liner	2-3 x wire wrapped screen, but less than WWS with gravel pack	most expensive
Application	borehole reinforcement for coarse grained formations	higher productivity wells in medium grained formations	retains sand grains of all sizes	retains sand grains of all sizes

Table 6 Comparison of Stand-Alone-Screens and Liners.

- *Feel free to review this table and discuss the application areas of different types of SAS.*

6.1.1 SLOTTED PIPE

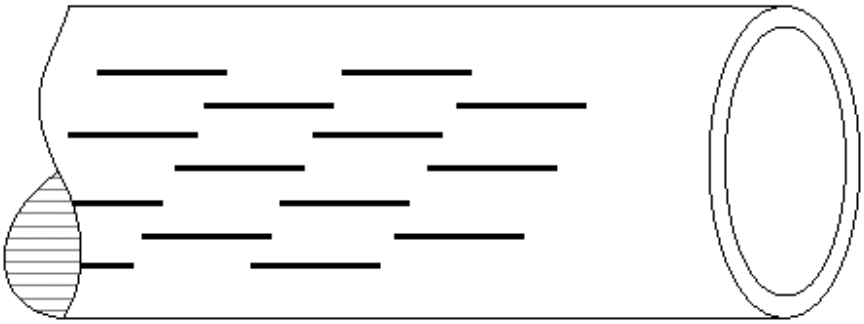

Figure 16 Slotted Pipe.

Slotted pipe, the original form of sand control, was first developed for use in shallow water wells drilled for agricultural and other purposes. It consists of a steel pipe (tubing or casing) with a series of parallel slots cut by a fine saw or laser through the metal (Figure 16). These slots, with a low inflow area of < 1% of the pipe surface area, can be arranged in different patterns. The width of these slots is normally made as small as mechanically practical in order to retain as large a fraction of the formation sand as possible. A minimum of 5% wt. of the formation's sand grains should be larger than the slot width required to form a stable arch, or bridge, around the slot.

Slotted pipe is mainly used today when a low cost, sand control option is required for an openhole oil well completion in an often shallow formation consisting of a rock with coarse sand grains.

6.1.2 WIRE WRAPPED SCREEN

Wire Wrapped Screens WWS, the most widely used screen type, consist of a rectangular (a.k.a. 'parallel') or triangular (a.k.a. 'keystone' or 'self-cleaning') shaped wire which has been carefully wound to give a constant gap between successive turns. The wire is held in place by spot welding the horizontal wire to vertical rods (a.k.a. ribs) placed at around 1 cm intervals around the screen's internal diameter (Figure 17).

The wire spacing between the horizontal wires is not only smaller, but is also more accurately controlled to give a more consistent and/or smaller gap than that found in a slotted pipe. Wire Wrapped Screens can thus retain finer grained formations than a slotted pipe. They also have a greater inflow area than the slotted pipe; making them more suited to higher productivity wells with a greater inflow rate per unit completion length.

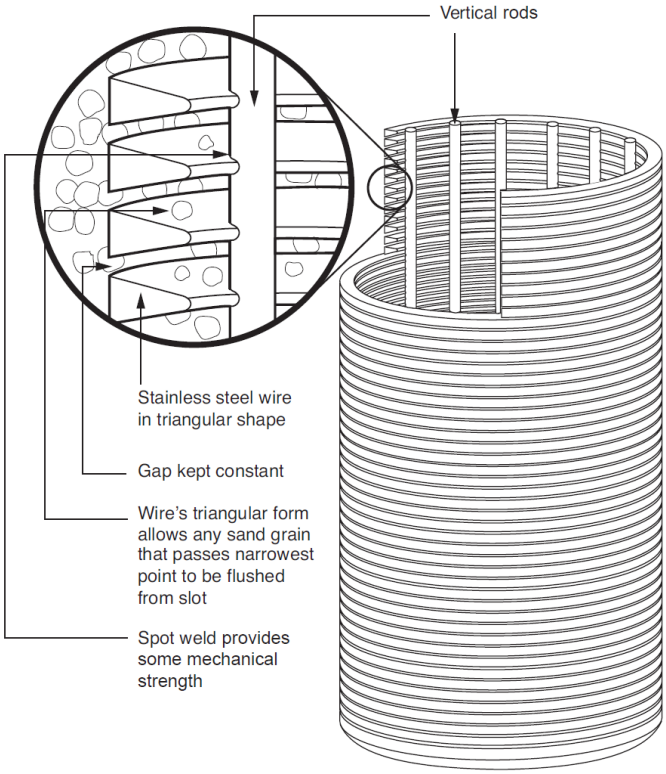

Figure 17 The Wire Wrapped Screen with a triangular-shaped wire.

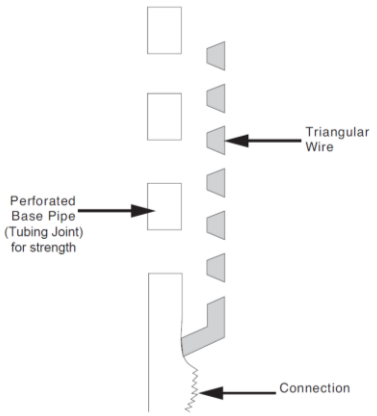

Figure 18 Cross section of Wire Wrapped Screen and the perforated base pipe inner support

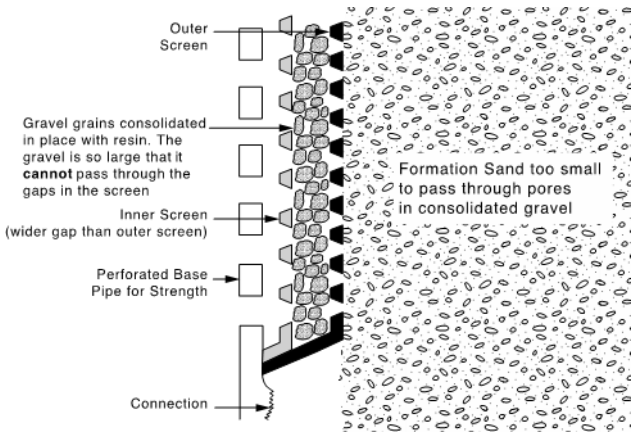

Figure 19 A Pre-Packed Screen.

Wire Wrapped Screens must be handled carefully at the rig site; their strength is much lower than that of a slotted pipe. The spot welds at the contact points between the vertical rods and the horizontal wires provides some mechanical strength, which is further increased by installing a length of base pipe (or tubing) with large perforations. The base pipe fits tightly inside the wire wrapped screen (Figure 18).

Sandscreens can be installed both in openhole and cased hole completions.

6.1.3 SCREENS PRE-PACKED WITH RESIN COATED SAND

Pre-Packed Screens are constructed from two concentric Wire Wrapped Screens with a layer of gravel placed in between them (Figure 19). They consist of:

- Dual, concentric Wire Wrapped Screens, optionally supported by a perforated base pipe.
- The gap between the two Wire Wrapped Screens being filled with gravel pack sand that often has been

coated with a thermosetting resin.

- The complete screen being placed in an oven and heated to a sufficiently high temperature for a long enough period that the thermosetting resin coating the gravel grains hardens ('cures') to create a strong ring of permeable, consolidated, grains of gravel pack sand.

The narrow pore throats of the consolidated gravel provide the sand exclusion filter that retains a good proportion of the formation sand in place. The greater complexity of the Pre-Packed Screen increases the cost compared to that of a Wire Wrapped Screen. The presence of the resin coated gravel, with its narrow pore throat diameter, provides a greater flow restriction than the wire wrapped screen alone. On the other hand, it also makes the screen more susceptible to plugging by formation fines, drilling mud and mud cake, dirty completion fluid, etc.

6.1.4 WIRE MESH AND EXPANDING SCREENS

The WWScreens and slotted pipes described above are suitable for **highly uniform** sands with relatively coarse grains, as mentioned. As for the formations with **highly non-uniform** sand size distribution: gravel packs (typically combining a WWS and well-sorted sand a.k.a. 'gravel' - *described later*), are most effective and commonly used to control sand production from. However, the inflow area of the Wire Wrapped Screen is reduced to some 3% of the open hole area once a gravel pack is installed. When the formation sand size distribution is **moderately uniform** (*the uniformity measure is described later*), development of standalone, premium screens with an increased area open to formation fluid inflow would be capable of minimising the inflow velocity through the screen and hence increasing the well productivity. Woven metal mesh membranes with a very high inflow area equivalent to 30% of the open hole area, and a size small enough to control sand particle movement without the need for a gravel pack {Figure 15(a)} have been developed.

The metal woven mesh sand screen (Figure 20, a 'Dutch twill' weave example) is one of the latest generations of the mechanical sand screen. They employ one or more layers of a woven mesh of metal threads. The layer(s) of woven mesh are strengthened by support layers and a perforated base pipe.

The expandable version of the mesh may also be expanded against the openhole {Figure 15(f)}. Here the screen's diameter is expanded by up to 50% by pumping, pushing, pulling or rotating an expansion tool through the (mild steel) screen once it has been installed across the completion interval (Figure 21). The expanded screen both reinforces the borehole wall and minimises annular flow between the sandface and the screen. This results in higher wellbore stability, a more uniform inflow distribution across the screen face and a reduced risk of screen erosion.

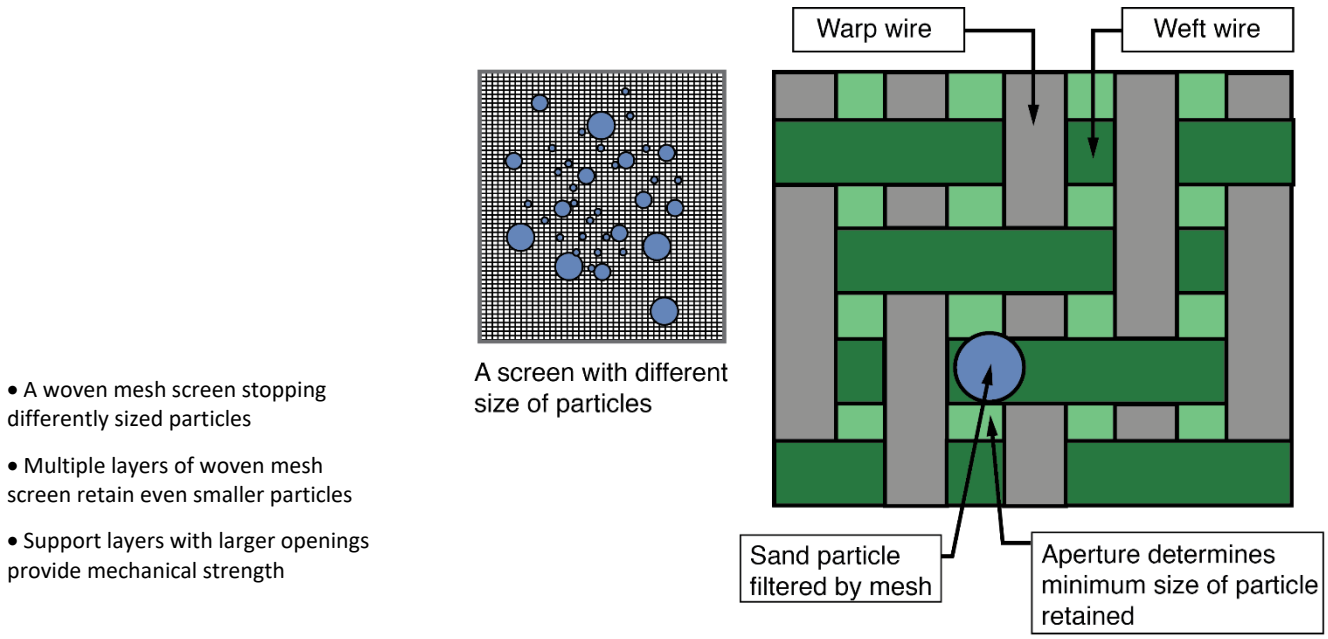

Figure 20 Metal woven mesh sand screens

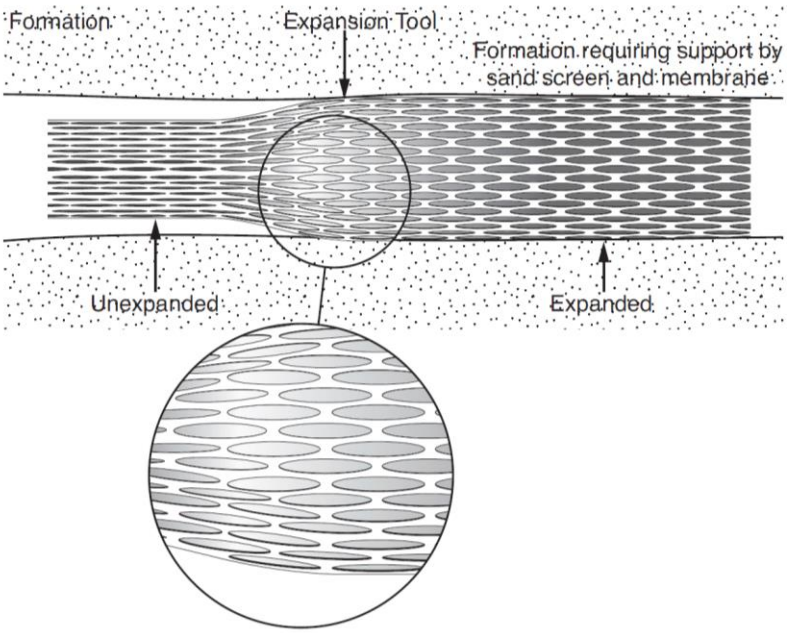

Figure 21 The Expandable Screen (*the cone-shaped expansion tool is not shown, only its position inside the screen*)

(Generally, annular flow in SAS-type completions has a negative effect: e.g. once part of the incorrectly designed completion adjacent to the sand production zone is plugged the annular flow will transport the sand and/or clays to the rest of the completion gradually plugging it as well. This can further lead to only a small part of the screen ('hot spot') remaining open to the high flow rate and thus a hole is eventually created by erosion, making this sand control completion inefficient from this moment).

Mechanical testing has shown that the expanded screen has a good burst strength; but a relatively low collapse strength. Screen plugging is thus a concern since it increases the collapse force exerted on the screen. The expanding screen is an effective technology for medium rate oil wells (≥ 10 - 15,000 bfpd), but is not effective for gas production. Expandable screens, as a recent technology, are still relatively rare.

6.1.5 APPLICATION OF OPEN HOLE COMPLETIONS

Open hole completions have become much more popular since horizontal wells became widespread. Their use avoids the high cost and technical difficulties in cementing and perforating long horizontal liners and casings. Some of the problems – and opportunities – presented to the completion design engineer when designing horizontal well completions are illustrated in Figure 22 - Figure 25.

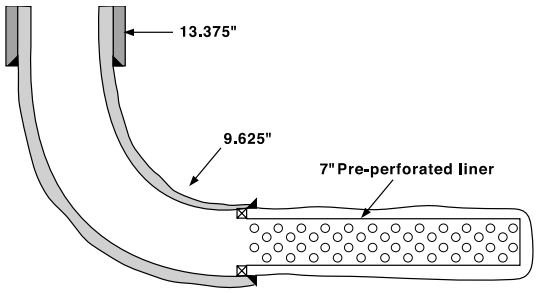

Figure 22 Conventional completion, no Sand Control.

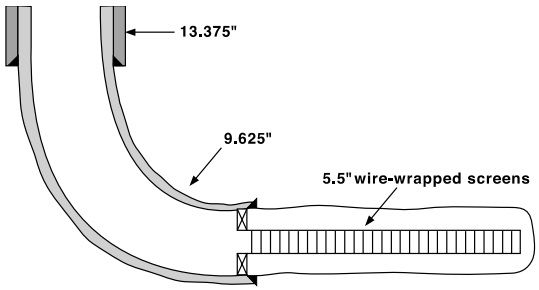

Figure 23 Conventional completion with wire wrapped screen to provide Sand Control.

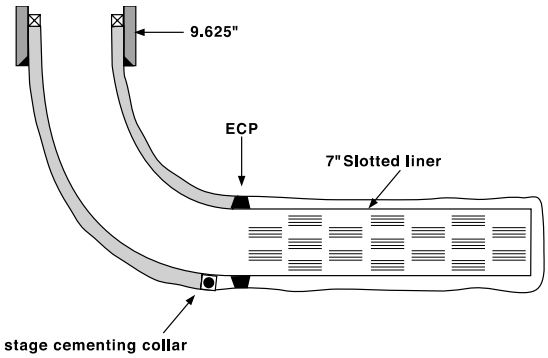

Figure 24 Low-cost option incorporating slotted liner for Sand Control.

Figure 22 shows a "conventional" well design with the production casing cemented in place just above or just into producing formation. The 7" pre-perforated liner provides support to the open hole but does not provide sand control. Sand control is provided in the completion shown in Figure 23 in which the 7" pre-perforated liner is replaced by a (smaller) 5.5" diameter wire wrapped screen. This change could increase the well cost by typically 10 - 20%.

Formations consisting of coarse sand grains allow this well cost to be decreased by substituting a 7" slotted liner for the wire wrapped screen (Figure 24). This low-cost option gives a typical well completion cost of only 60% of that for above wire wrapped screen case.

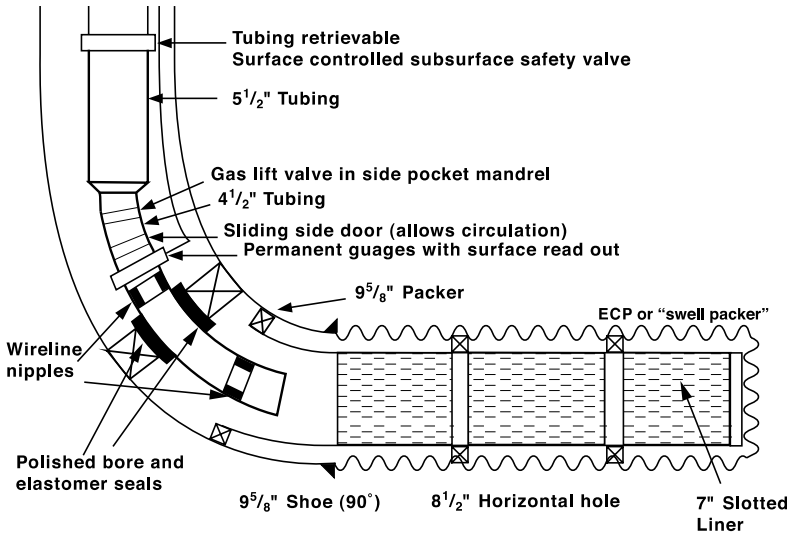

Figure 25 Horizontal open hole well completion.

A more complex Horizontal Well Completion is pictured in Figure 25.

The ECPs (External Casing Packers) or swell packers zonate the completion interval making it possible to isolate watered out zones later. ICDs (inflow control devices, see Chapter 1), optionally with screens, can also be added into or substitute such completion to improve inflow control, reduce annular flow and sand production.

6.2 Drilling fluids for Screen-only, Open Hole Completions

Screen-only Open Hole completions {Figure 15(a) and (f)} place special requirements on the drilling fluid properties. Figure 26(a) illustrates the results of a large-scale experiment in which the mud cake was deposited in a stimulated section of a horizontal well. An acid treatment removed the mud cake covering the upper part of the open hole, but left extensive mud cake remnants on the lower sections. Simulated production from the reservoir into the well resulted in more than half the screen area being covered by mud cake, reducing fluid flow {Figure 26(b)}.

Figure 26 (b) shows how conventional remedial treatments with strong acids cannot completely remove all the filter cake from the open hole. Such acids will also dissolve the formation's cementing material, destabilise weak/un-consolidated formation and, possibly, create permeability impairment. A strong acid will not dissolve the filter cake evenly, but a limited number of small (worm-)holes in the mud cake at points where it is thinner and/or more reactive. The acid is then lost to the formation by high-rate leak-off through these holes; and is no longer available to dissolve the rest of the mud cake.

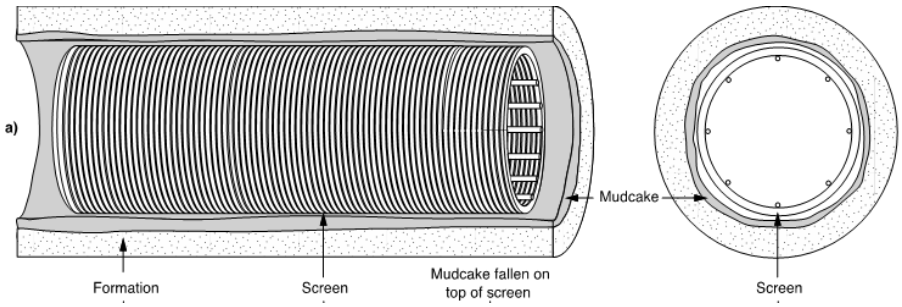

Figure 26 ***(a)*** Mud/mud cake deposited on horizontal well bore

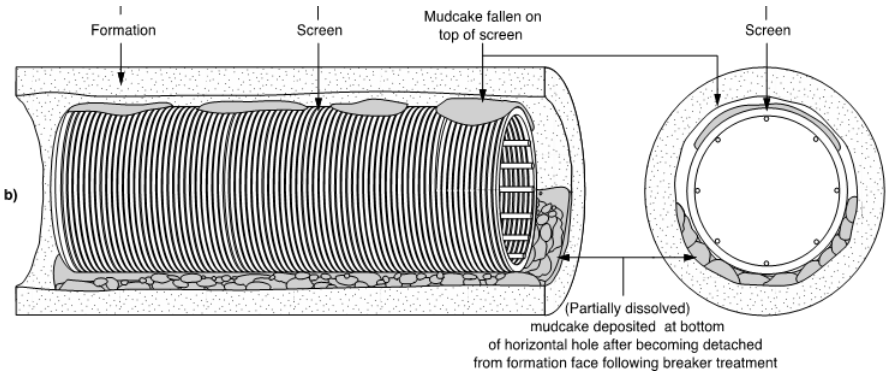

Figure 26 ***(b)*** Screen appearance after breaker treatment and placing the well on production. Partial dissolution leads to undissolved mud cake lying on the top of the screen and filling the lower portion of the annulus

One solution to the problem illustrated in Figure 26 (b) has been to ensure that the remedial fluid remains in the wellbore for a longer time. This can be achieved by placing a weaker acid in the wellbore where it will evenly dissolve the mud cake rather than form wormholes.

The second solution is to avoid the need for a remedial acid treatment, e.g. by using a drilling fluid whose mud cake can be detached from the borehole wall by imposing a low pressure drop across the mud cake. This low "mud cake lift-off pressure" ensures that the filter cake easily, and evenly, lifts-off when the well is placed on production; even though the production drawdown pressure in a horizontal well is often low and decreases from the heel of the well towards the toe.

The mud cake should not only "lift-off", but also break-up and flow between the narrowest gaps in the screen. This process is accelerated if some of the mud cake is soluble in the produced fluids (water or oil). Specialist "drill-in" fluids are now available from various service companies that meet these requirements.

The applicability of a screen in a given formation is normally first tested at lab conditions by e.g. pumping slurry with formation sand (or solids representing it) across the screen, and measuring sand retention vs. pressure drop. The expected mud cake can be added to simulate its possible retention by the screen.

Special types of pre-installed valves (Sand Cleanout Valves SCOVs) can also be used that are pre-programmed to stay open during the well cleanup time to let the mud cake, sand and debris from the annulus into the tubing, and then the SCOVs close for good once the pre-set time is over and the well is put on normal production.

The SASs are often suitable in the situations where the risk of sand production is low and the formation sand is generally coarse and well sorted. *(The sand control completion manufacturers often provide recommendations on the optimal sand control completion based on the sand production likelihood and formation sand uniformity, as well as the guidelines how to select the right SAS gap (a.k.a. 'gauge'), e.g. many SAS gaps are selected to stop the largest 10% of the formation sand (a.k.a. '10th percentile' or d_{10}) or so).* Otherwise, in the majority of cases the gravel pack, being a more efficient filter and able to deal with non-uniform poorly-sorted sand, is the most common and efficient solution.

6.3 Gravel Pack

6.3.1 THE EXTERNAL OR OPEN HOLE GRAVEL PACK

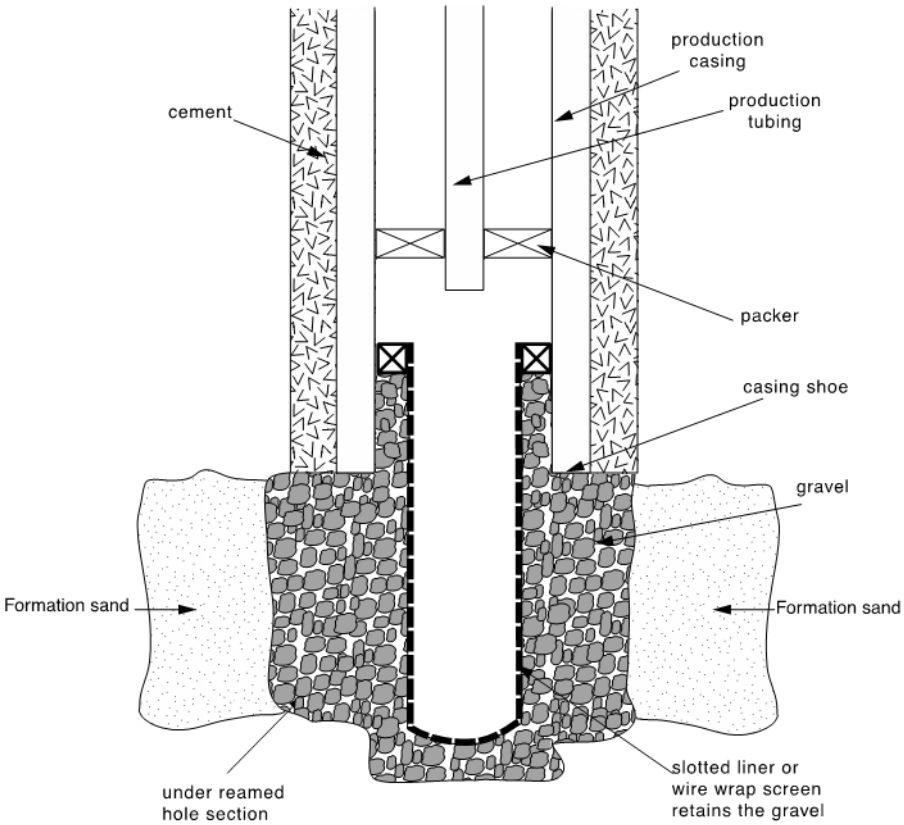

Figure 27 An external gravel pack

The screen of an external, or open hole, gravel pack (Figure 15(b)) is installed near the shoe of the production casing or production liner. The annulus between the screen and the formation is then tightly packed with gravel. As was explained, 'gravel' is essentially well sorted sand like e.g. the one used in fracturing proppants. The hole is normally first under-reamed (Figure 27), an operation that involves enlarging the gap between the sandface and the screen (typically by 10 - 15 cm) using a special drill bit (an under reamer). The under reamer has multiple arms equipped with cutters that expand and enlarge the hole when the drill string is rotated. The drill-cutting are removed by circulating a non-damaging fluid during the process of hole enlargement. This increases the wellbore diameter and hence productivity as well as ensures that the gravel layer is sufficiently thick (typically at least 3 in. thick) to act as an efficient filter, because the screen alone is unable to stop formation sand since this screen is designed to be slightly smaller than the smallest gravel grains, while the formation sand is much smaller than that (the gravel is selected coarser than formation sand for the reasons explained later).

6.3.2 THE INTERNAL GRAVEL PACK

An external (a.k.a. openhole) gravel pack is almost always a single zone completion below the shoe of the production casing or liner, as discussed above. An internal (a.k.a. cased-hole) gravel pack, by contrast, has the advantage of allowing multiple zone completions since the screen of an internal gravel pack is placed **inside** the casing or liner (leaving the space normally around 1 inch wide), and the gravel is placed in the screen/casing annulus and in the perforations (Figure 28). The cased hole completion makes it easier to install multi-zone elements like multiple packers etc. (*This is not to say the internal gravel pack is not used as a single-zone variant as well*).

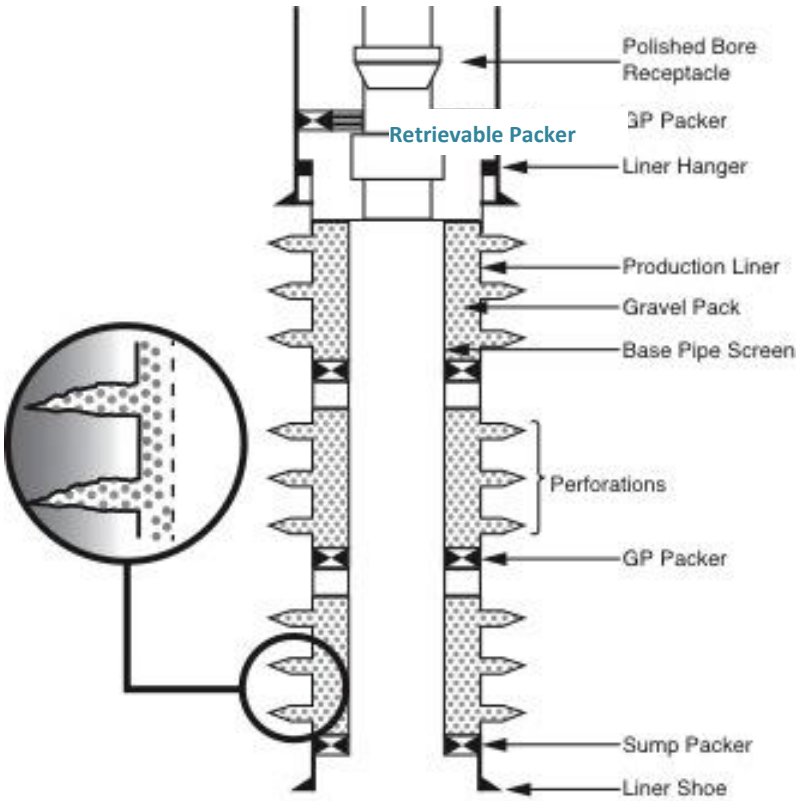

Figure 28 A triple zone, internal gravel pack completion

Completely packing the screen/casing annulus and the perforation tunnel with gravel {Figure 29(a)} is essential for a long-lived, productive completion. If the packing is imperfect, then partial filling of the perforation {Figure 29(b)} results in high velocity, turbulent flow through the perforation tunnel. Such high flow rates will agitate the gravel, allowing the gravel to erode a hole in the screen by repetitively striking it. The sand control completion has now prematurely failed since formation sand and gravel grains can now enter the well and cause production problems.

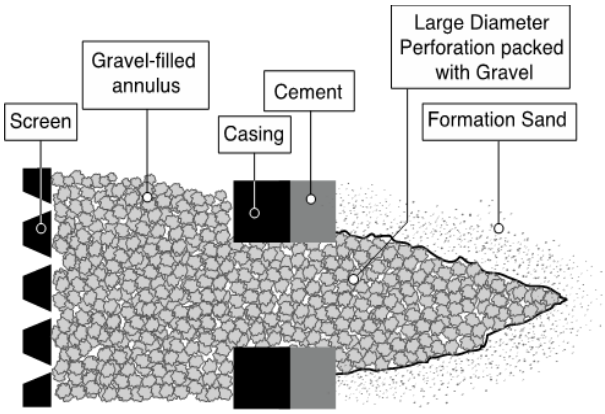

Figure 29 ***(a)*** A completely gravel-filled, internal gravel packed perforation

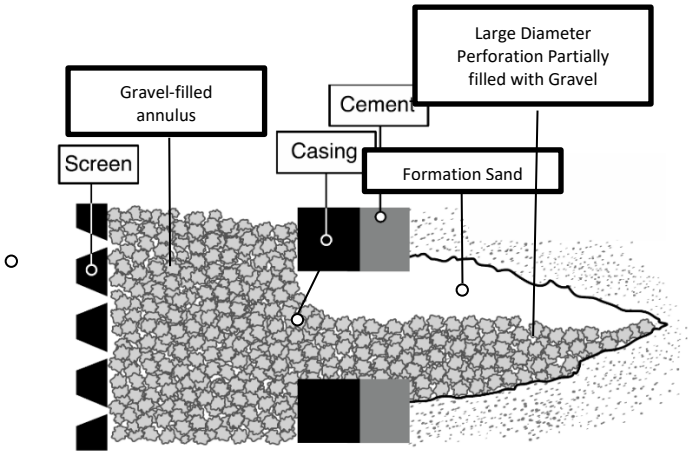

Figure 29***(b)*** A partially gravel-filled, internal gravel packed perforation

Even if the velocities are not high enough to erode the screen, another problem with partly packed space is the opportunity for the formation sand to enter and mix with the gravel within the perforation tunnel, dramatically reducing its permeability (from several Darcies or tens of Darcies to a value comparable to the formation permeability) and thus well productivity.
Let alone a poorly packed completion does not form an efficient filter and the formation sand production takes place.

6.3.3 "FRAC-AND-PACK"

Field experience has shown that internal gravel packs are often highly impaired. The combination of an internal gravel pack and a short, highly conductive, (tip screenout) hydraulic fracture that is propped (*held open)* by a thick (1 - 2 in.) layer of gravel pack sand is known as "Frac-and-Pack" {Figure 15(d) and Figure 30)}.

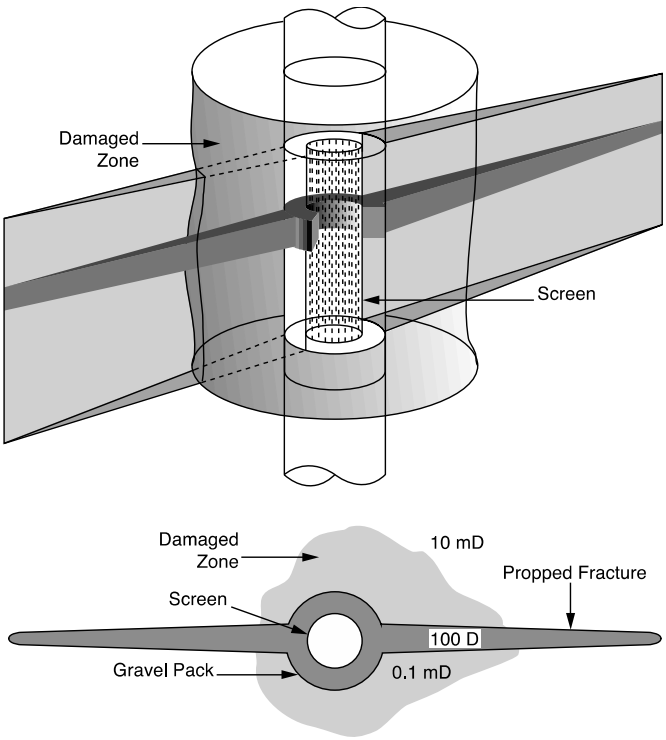

Figure 30 Conceptual view of a "Frac-and-Pack".

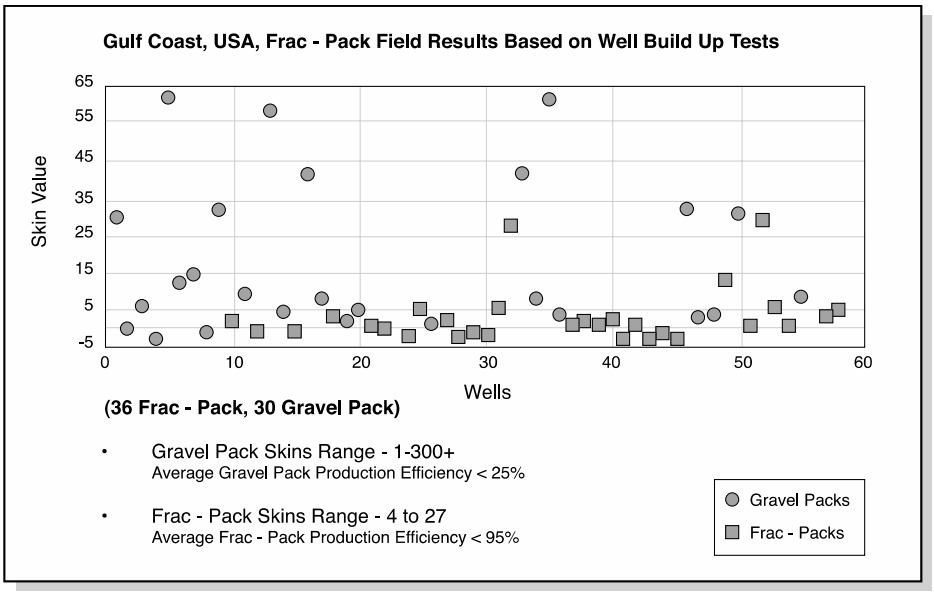

Figure 31 "Frac-and-Pack" completions improve well performance

Figure 30_{lower} is a conceptual plan view of a short, highly conductive, hydraulic fracture bypassing a low permeability zone with formation damage surrounding the wellbore. Field experience showed that the combination of a hydraulic fracture and a gravel pack led to completions with a lower "skin", and hence higher well productivities than only a gravel pack (Figure 31). The (vertical) hydraulic fracture also ensures that the well is connected to all thin, laminated sands, some of which might be missed by a conventional gravel pack. Besides, achieving the target production with fracpacks at lower drawdown is itself a good sand production prevention measure.

(In some cases the 'screenless fracpack' option is suitable, where the short TSO fracture is created from a strong, perforated interval and connects into the weaker ones. The fracture's proppant acts as a filter, provided it does not flow back excessively when the well is returned on production.)
(In general, where proppant flowback is excessive, it may be held in place e.g. by using resin coated sand proppant, and/or by adding fibres to the proppant to improve its retention within the fracture).

6.4 Gravel Pack Sand Selection

Gravel pack sand, or gravel, consists of well rounded, clean (i.e. with minimal fines and acid-soluble material) grains with dimensions between a specified maximum and minimum size. The specification for the gravel and proppant used for gravel packing operations is the same as for proppant and is defined by the sieve mesh size as was explained in Chapter 9.

The grains are carefully sieved to ensure that 98% wt. of the gravel sample is between the maximum and minimum specified sieves. The source of the gravel is also carefully selected to meet minimum roundness, sphericity and grain strength criteria together with a minimum fraction of the acid soluble material and the clay content.

Quartz (sand) gravel is often employed, but synthetic "gravels" and proppant are also available at a premium price. These man-made materials can have a higher strength, lower density, greater sphericity and roundness, and hence higher permeability, than "natural" gravel from a sand quarry.

Properties of Standard Gravel Pack Sands			
US Mesh	**Range Gravel Size (μm)**	**Median Gravel Diameter (μm)**	**Typical Permeability (D)**
40 / 60	425 - 250	340	55
20 / 40	850 - 425	640	170
12 / 20	1700 - 850	1275	600

Table 7 Properties of several standard gravel pack sands.

A limited range of gravel pack sand sizes are available commercially (including the ones in Table 7). As mentioned, the sieve mesh number refers to the number of equally spaced openings per inch of screen. Therefore, the lower the mesh number, the larger the diameter of the sand grain.

Placing the correctly sized gravel pack sand around the sand screen acts as a high permeability filter that does not significantly restrict the inflow of oil or gas into the well.

- Too large gravel grains (Figure 32left) allow the grains of the formation sand to invade the pore throats of the gravel, creating a low permeability gravel/sand mixture.

- Too small gravel grains reduce the size of the pore throats between the gravel grains. They are now small enough to retain the formation sand grains (Figure 32right), but have a lower than optimal permeability. Gravel with a smaller than necessary pore size will also show an increased susceptibility to blockage by fines, which should be avoided.
- The optimal gravel pack sand combines the maximum possible permeability without being invaded by the formation sand grains or blocked by "fines" production.

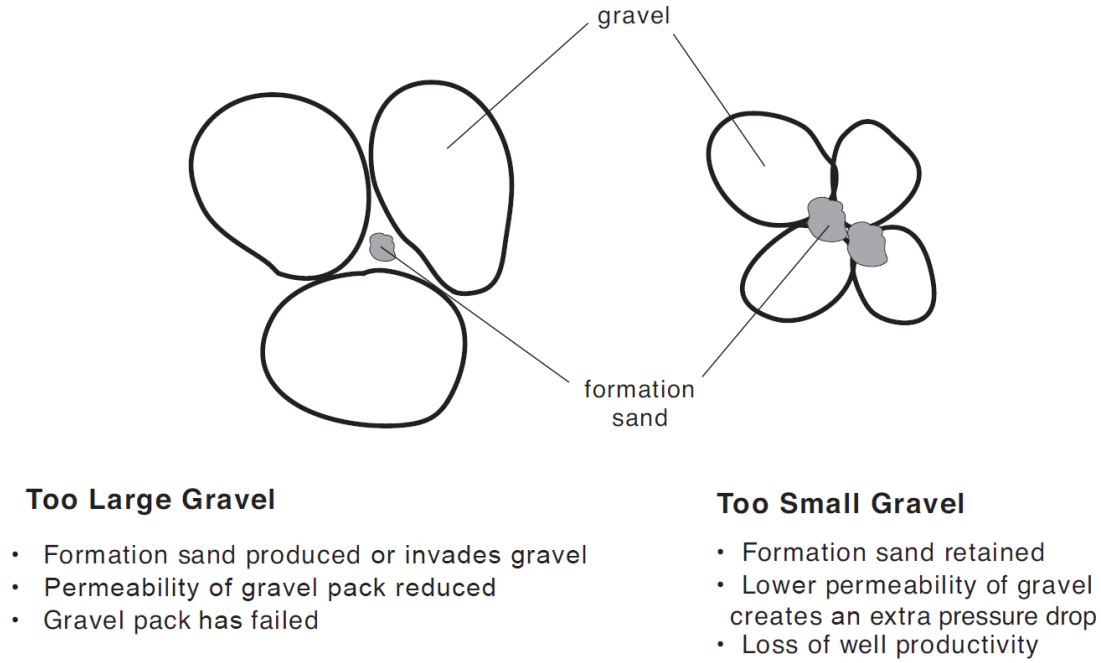

Figure 32 Effect of incorrect gravel pack sand selection

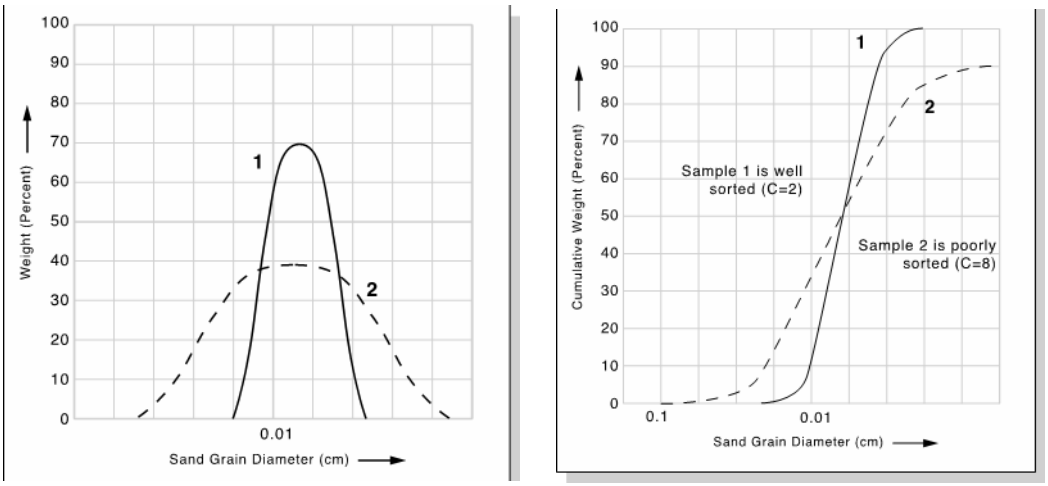

Figure 33 A well sorted (C ≈ 2) and a poorly sorted (C ≈ 8) sand

The formation sand size distribution, used to select the optimum size of gravel, is characterised by sieving a representative sample of the formation sand through a stack of pre-weighed sieves of progressively smaller mesh size. It's important to collect representative formation sand samples, e.g. from the core and not from the surface samples (where only the smallest particles have been lifted by the flowing fluid).

The weight of sand, trapped on each sieve, is measured and the cumulative distribution is plotted (Figure 33_{right}) using log-linear graph paper. The size corresponding to a cumulative weight percentage of 10%, 40% and 90% is known as d_{10}, d_{40}, and d_{90} respectively (Figure 34). E.g. 40th percentile d_{40} corresponds to the particle size such that 40 wt% of all the sand grains are larger than it.

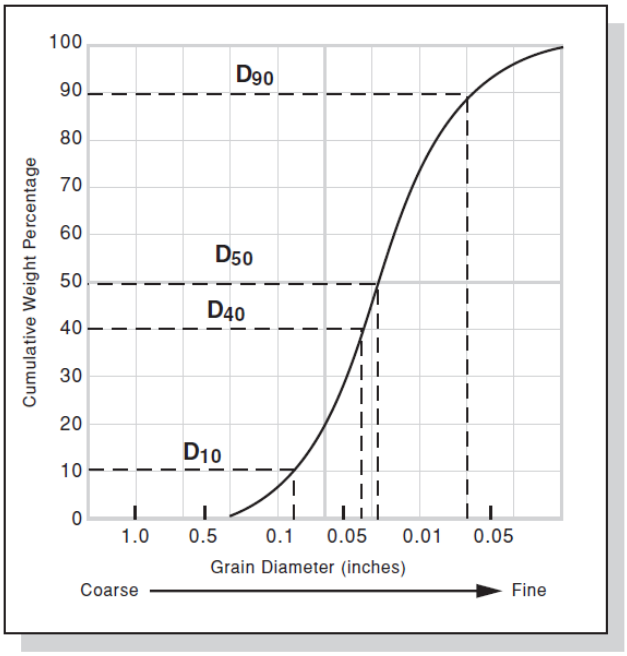

Figure 34: Sieve Analysis measures

Alternatively to using sieve analysis, it is more common nowadays to use LPS (laser particle size) analysis methods that are faster and often cheaper.

The Uniformity coefficient C{= d_{40} / d_{90}} represents the "sharpness" of the weight distribution of the formation sand grains (*and is also often used to recommend a suitable, sand control completion type*).

Where: 3 > C well sorted, highly uniform sand *(WWS or prepacked screens are often preferred)*

3 < C < 5 uniform sand *(premium mesh screens are often preferred)*

5 < C < 10 moderate/poorly sorted sand *(gravel packs or expandable screens are often preferred)*

C > 10 poorly sorted highly non-uniform sand (*gravel packs are preferred)*

Figure 33_{left} and $_{right}$ include a comparison of the weight and the cumulative weight distributions of a well-sorted (C ≈ 2) and a poorly-sorted (C ≈ 8) sand.

There are several approaches to select the appropriate gravel size. For instance, one of the popular ones is by Saucier who systematically studied the selection of the gravel pack sand based on the formation sand size. He simulated the production performance of a gravel pack by measuring the change in permeability of a cylindrical sample prepared from formation sand and gravel pack sand (Figure 35). Well production was simulated by directing the flow from the formation sand to the gravel. Both the initial and the final, stabilised permeability of this two-stage sand pack were measured after a long period of flow.

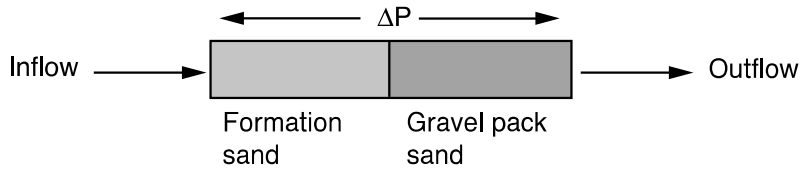

Figure 35 The two-stage sand pack used by Saucier to simulate flow into a gravel pack.

The experiment was repeated (Figure 36) for many combinations of gravel and formation sand sizes. The [$d_{50\ gravel}/d_{50\ formation\ sand}$] ratio was varied between 2 and 20. Figure 36 shows that the smallest gravel:formation sand size ratios formed an effective filter for sand control with the smaller gravels having a lower permeability due to their smaller grain size. Invasion of the gravel by the formation sand began to be observed as a reduced, long-term permeability once the [$d_{50\ gravel}/d_{50\ formation\ sand}$] ratio became greater than 6.5; though effective sand control was maintained up to the ratio of 10.

The permeability of the sand/gravel mixture becomes less than that of the formation sand if large-scale mixing takes place ($d_{50\ gravel}/d_{50\ formation\ sand}$ ratio = 10 - 12). The combined permeability increases but sand control decreases as the $d_{50\ gravel}/d_{50\ formation\ sand}$ ratio increases further. The pore throats in the gravel have become sufficiently large that the formation sand passes through the gravel at a value of 17.

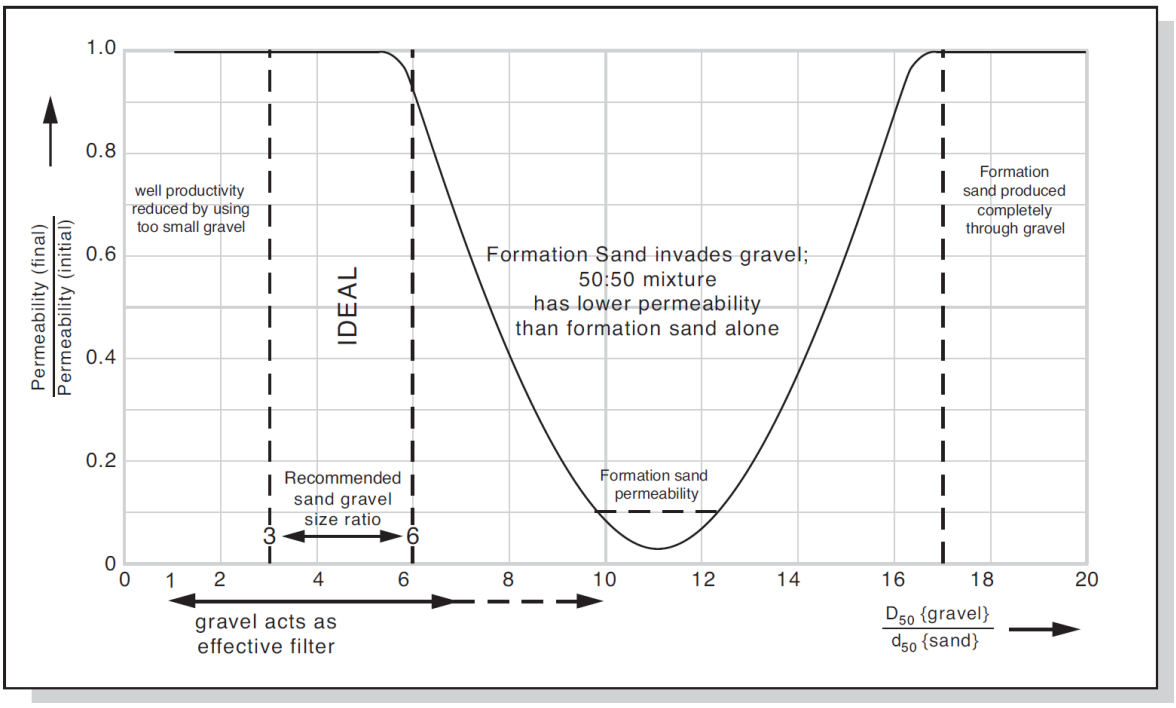

Figure 36 Schematic diagram of sand/gravel interaction by Saucier.

Saucier recommended that for effective sand control of the target formation sands without losing much of the gravel pack permeability the gravel should be selected as follows:

Minimum $d_{50\ Gravel} = 3 * d_{50\ Formation\ sand}$

Maximum $d_{50\ Gravel} = 6 * d_{50\ Formation\ sand}$

Similar experiments have been repeated many times and (slightly) different gravel size selection criteria were also developed. For example, Schwartz recommendations are listed below and also depend on the formation sand sorting:

$d_{10\ Gravel} = 6 * d_{10\ Formation\ sand}$ for $C < 5$
$d_{40\ Gravel} = 6 * d_{40\ Formation\ sand}$ for $5 < C < 10$
$d_{70\ Gravel} = 6 * d_{70\ Formation\ sand}$ for $C > 10$

6.5 Internal Gravel Pack Perforation Criteria

The pressure drop across an internal gravel pack's gravel-filled perforations is an important parameter when designing this internal gravel pack. This is due to the need to ensure a laminar flow regime within the perforation tunnels. Figure 37 presents pressure drop calculations as a function of flow rate for 1 cp oil flowing through different diameter perforations filled with 20/40 US mesh gravel with a permeability of 180 Darcy.

Darcy's Law is no longer obeyed at higher (than laminar) rates causing the pressure drop versus flow rate plot being no longer a straight line. This occurs at flow rates as low as 5 bbl/d/perf for small diameter perforations increasing to 25 bbl/d/perf for the large diameter holes.

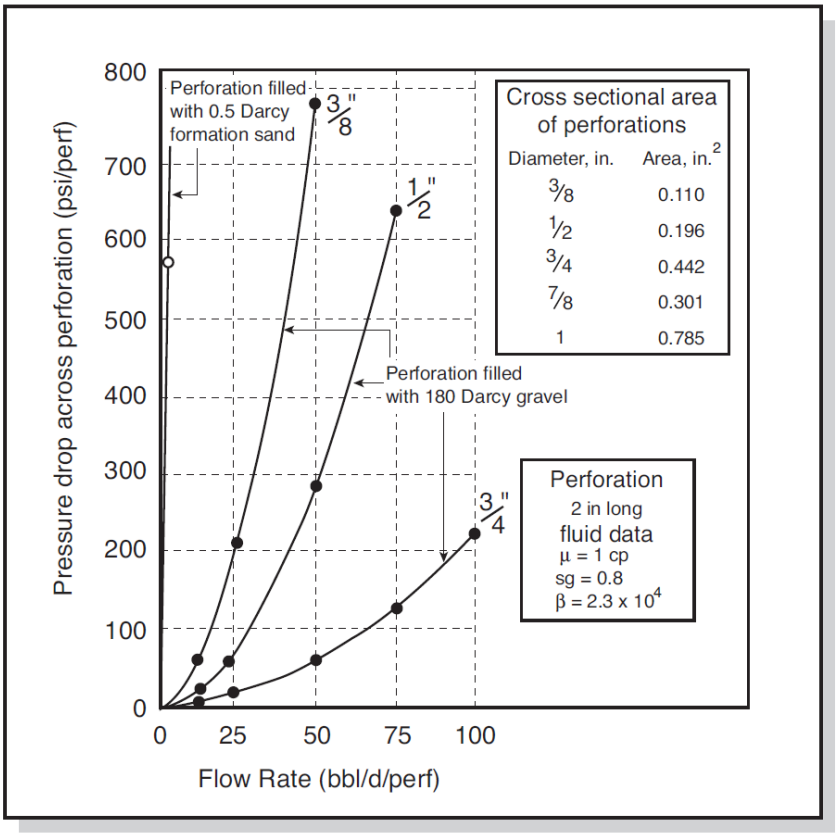

Figure 37 The impact of non-Darcy flow depends on perforation-tunnel diameter.

Note: In this experiment the maximum pressure loss happens across the perforation tunnel filled with the 500 mD formation sand. This is another reason for completely filling the perforation tunnel with gravel, not leaving any space for the formation sand.

The perforation programme should be chosen so that the gravel-filled perforations do not limit the oil/gas inflow into the well. Figure 37 implies that the productivity of a gravel pack completion is maximised by specifying many, large diameter perforations. The completion engineer's specification for the perforating programme of an internally gravel packed well should thus include a:

1. High perforation density (*number of perforations per unit length, such as 12 to 16 shots/ft*) and
2. Wide diameter perforations ("*big hole" shaped charge design and as high as possible weight of explosive*).
   The perforation tunnel should also be 5 times the diameter of the largest gravel pack sand grain to ensure that a highly concentrated sand slurry can be pumped through the tunnel without creating a blockage (or "sand-out").

> Feel free to attempt Tutorials 1-2

6.6 Surface Operations when Gravel Packing

The fluid used to carry the gravel into the well performs functions described in Table 8. Its properties range from being similar to that of water to a highly viscous gel.

Function	Comment
Control formation pressures	Similar to drilling fluids
Transport gravel to completion interval	BOTH at surface and downhole
Return (reverse) excess gravel from completion interval to surface	As above
"Clean" fluid essential	Filter solid particles in water and (undissolved) polymer residue
Compatible with clay particles in formation	Add 1% wt KCl
Viscosity of viscous fluids must degrade to allow production to surface	Add chemical breaker (acid or oxidising agent)

Table 8 Gravel Packing Fluid Functions

Typically, a filtered, 1% wt. potassium chloride (KCl) brine base fluid is used. A polymer e.g. hydroxyethyl cellulose (HEC) is added if an increased viscosity is required. The surface operations occurring during a gravel packing treatment are summarised in Figure 38. Low concentrations of gravel are added continuously ("on the fly") if a low viscosity brine is chosen; while higher gravel concentrations may be used with viscous fluids. The gravel slurry is then pumped into the well using a high-pressure pump.

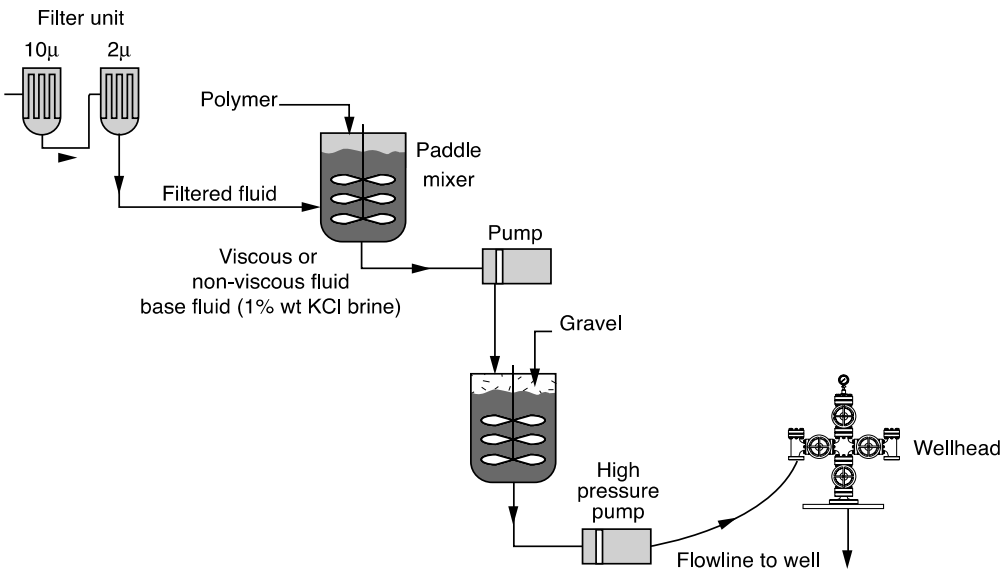

Figure 38 Surface equipment for a gravel packing operation

6.7 The Gravel Pack Operation

The most common way to install a GP is by circulation. The same process is followed when installing an Internal or an External gravel pack. Figure 39 illustrates the main stages of a typical gravel pack operation for an external gravel pack. The wire wrapped screen or liner has been placed across the completion interval with a length of normal tubing above it. The "cross-over tool" is mounted above the tubing. The "cross-over tool" allows various circulation paths from the tubing to the annulus to be selected.

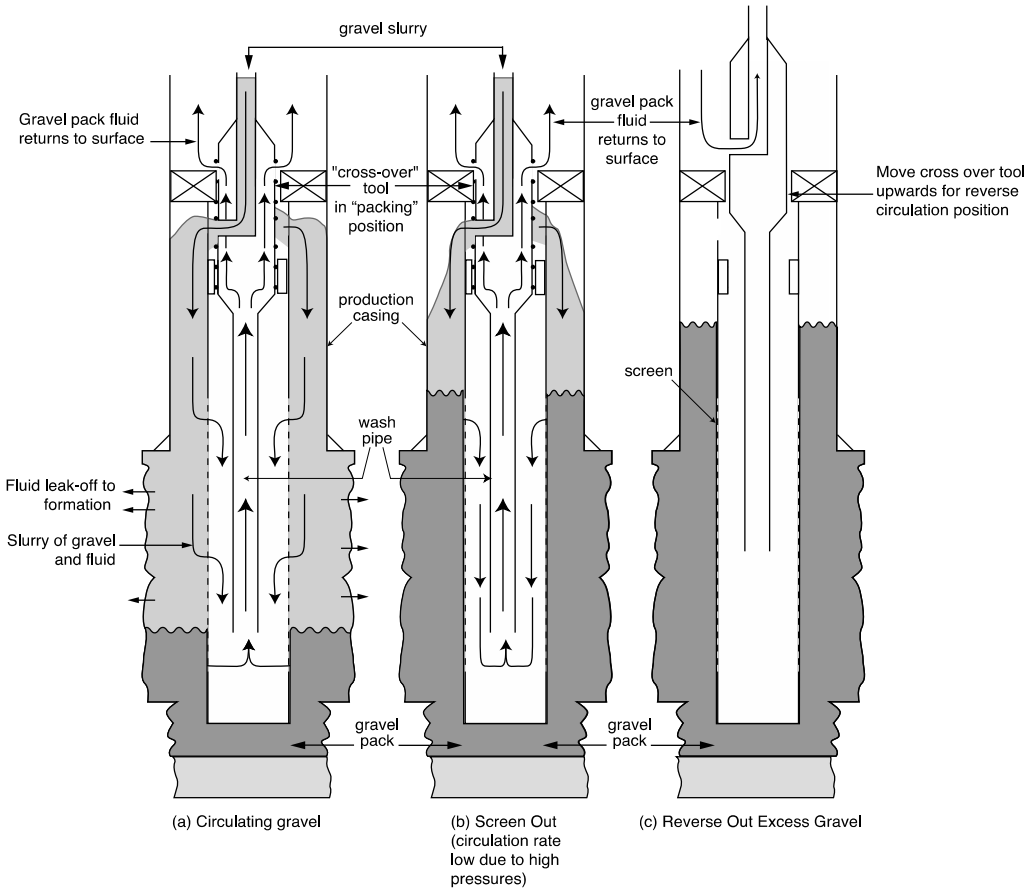

Figure 39 Gravel packing with a crossover tool.

The gravel packing operation with a low viscosity fluid is as follows:

1. Gravel slurry is pumped down the tubing and "crosses-over" into the liner/casing annulus. The gravel falls to the bottom of the hole where it builds upwards from the bottom. The fluid flows through the liner, up the wash pipe and "crosses-over" so that it can return to the surface via the casing/tubing annulus {Figure 39(a)}. The circulation pressure is chosen so that in the ideal case approximately 50% of the fluid "leaks-off" into the formation and 50% returns to the surface.

2. The pressure rises rapidly once the gravel level has covered the top of the liner since the flow through the gravel is leading to a much higher pressure drop. This is called a "sand-out" or "screen out" {Figure 39 (b)}.

3. The "cross-over" tool is raised to close the flow paths to the gravel pack and allow circulation directly from the tubing to the tubing/casing annulus {Figure 39 (c)}. Reverse circulation, DOWN casing/tubing annulus and UP the tubing, allows the excess gravel slurry to be recovered at the surface.

4. The "cross-over" tool and work string are recovered and the final well completion is installed.

The volume of gravel installed in the gravel pack is measured by comparing the volume of gravel pumped into the well and the volume recovered by reverse circulation after the "screen out". This volume may then be compared with the theoretical volume calculated from the dimensions of the gravel pack.

The premature screenout can happen if the fluid is leaking off into the formation too fast (e.g. there is a thieve zone or a fracture, either natural or the one created accidentally). The slurry may dehydrate and the remaining sand will bridge the annulus not letting the slurry to flow further and pack the rest of the completion. This must be dealt with by e.g. selecting higher fluid viscosity, lower gravel concentration, higher pump rate, or introducing mechanical bypass elements into the screen e.g. short 'shunt tubes' arranged along the screen on the outside to let the slurry pass.

6.8 Gravel Pack Evaluation

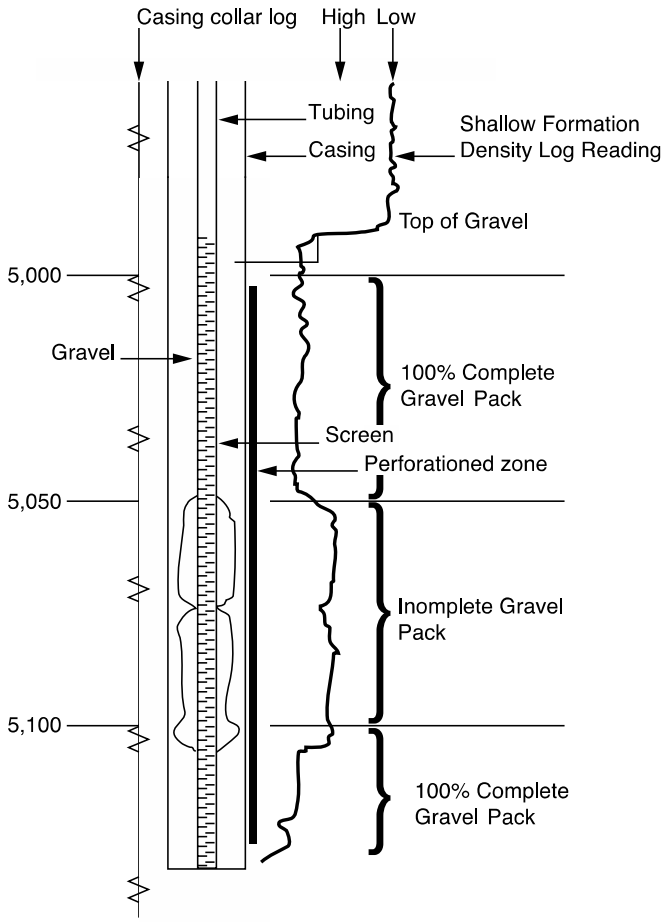

Figure 40 Evaluation of an internal gravel pack with a nuclear density log.

A gravel pack evaluation log can be run if the installed volume is significantly lower than the theoretical volume. A logging tool (e.g. a neutron density log) that measures the density in the annulus through a steel pipe is required. Intervals with an incomplete gravel pack give a lower shallow density reading than intervals with a good pack. However, the readings are also influenced by changes in the completion equipment, such as connections, packers, transition from wire wrapped screen to tubing etc. These effects have been schematically illustrated in Figure 40.

Engineering judgement must now be used to decide whether to:

- Recover the gravel pack screen and immediately repeat the gravel pack operation after installation of a new screen.
- Place the well on production and monitor the well for sand production.

The former option is normally chosen if cost of mobilising the drilling rig to the wellsite at a later date is high.

6.9 Advantages/Disadvantages of Gravel Packing Summarised

Gravel packing is the most widely used form of sand control. Its advantages of easy installation in the field and wide applicability to all types of well completion scenarios in weak sandstone reservoirs often outweigh its disadvantages (Table 9).

Advantages	Comment
Effective over long intervals	>100 m operationally possible
Copes with varying rock properties	Clay / Silt particles can pass through gravel pack if they are small enough
Employs simple, non-toxic materials	Gravel placed with water based fluids
Disadvantages	**Comment**
Mechanical restriction in wellbore	Production logging not possible
Workover difficult	Requires removal (fishing) of packers / screens etc. A time consuming process
Expensive for multiple intervals	Consider co-mingled production
Diminished workover options	Difficult to either identify the source and then shut-off undesirable water and gas
Sensitive to poor completion practices	Many points where permeability damage can be created

Table 9 Gravel Packing Advantages and Disadvantages

6.10 Fluid Loss Control

Great care is taken to prepare the well in an unimpaired state prior to the start of the gravel pack operation. This leads to the result that even a small overbalance of the completion fluid's hydrostatic head compared to the reservoir pressure leads to large-scale losses of completion fluid into the formation. This is undesirable since it often leads to extensive formation permeability impairment. Generally, four options are mostly used:

- Placing a small volume of a very high viscosity fluid across the perforated zone. This either contains a viscosity breaker (which will degrade the viscosity after a specified time/temperature exposure period) or it is removed by pumping acid immediately before (preferred) or after the gravel pack has been completed

- As above, with filter cake forming solids (e.g. oil soluble resin or water soluble salt crystals) which will dissolve once production commences

- Mechanical solutions such as a LBFV or Large Bore Flapper Valve (Figure 41). The LBFV is run

into the well in the open position – being held open by, for example, the wash pipe of the gravel pack assembly. On withdrawal of the washpipe, the spring holds the flapper valve closed against the seal; thus preventing further brine losses from the tubing to the formation. The LBFV is constructed from glass or ceramic material so that it can be broken by pressure or mechanical impact after the completion has been installed.

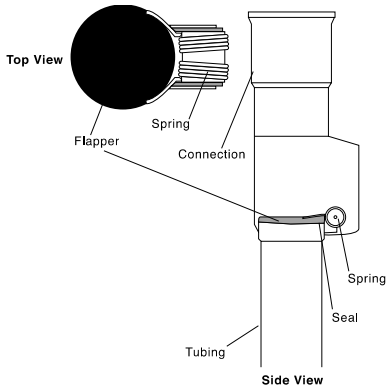

Figure 41 Large - Bore Flapper Valve.

- A second mechanical solution is the Formation Inflow Valve (FIV) Figure 42 shows. This is a large bore adaptation of a drill stem test valve – it can be open and shut by either annulus or tubing pressure. The FIV is placed near the bottom of the tubing string. A seal assembly is placed at the bottom of the tubing string. The FIV is large enough for perforating guns mounted at the end of a work string to be run through it.

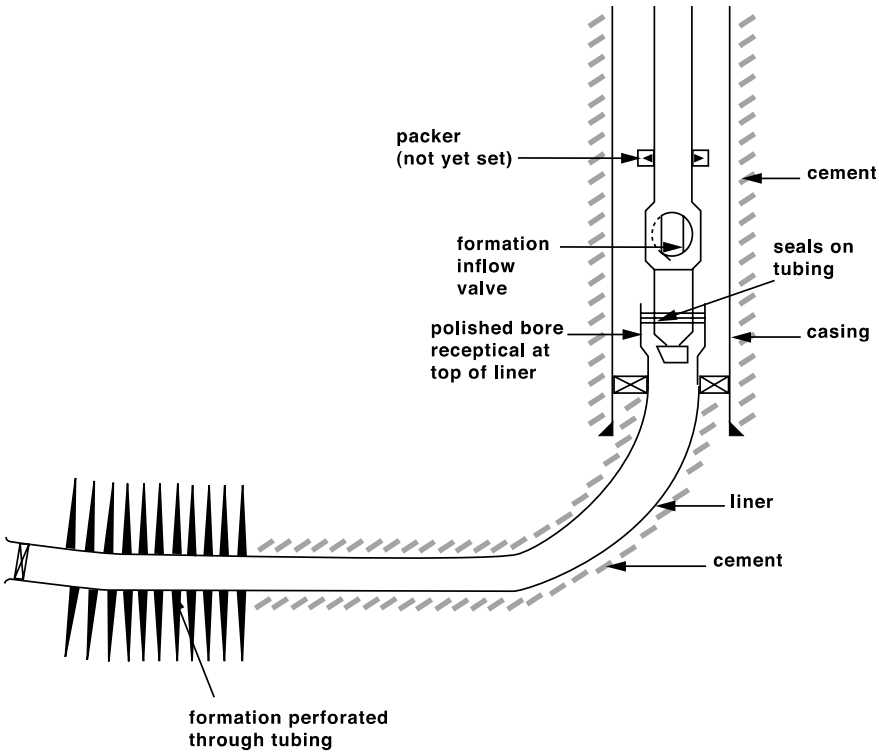

Figure 42 Horizontal well completion schematic.

6.11 Gravel Placement with Low Viscosity Fluids

The manner in which the gravel pack is formed depends on the viscosity of the fluid and the deviation angle that the well is drilled through the completion interval. The key points concerning low viscosity fluids are summarized as follows:

- Gravel placement with low viscosity fluids (a.k.a. 'water packing') is mainly applied to external gravel packs or shallow formations. The low gravel concentrations (2 lb gravel/gal fluid) and the low frictional pressure losses minimise the chance of fracturing these weak formations.

- The time required to pump all the gravel and complete the gravel pack is long due to this low gravel concentration, despite the high pump rate of 5-10 bbl/min.

- This high pump rate can cause permeability impairment due to gravel/sand intermixing.

- The large volumes of fluid pumped during the operation through the screen/liner increases the opportunity for liner or screen plugging.

Large scale laboratory tests have shown that the gravel pack is formed from the bottom upwards in **vertical** or low deviation (< 45º) wells (Figure 43).

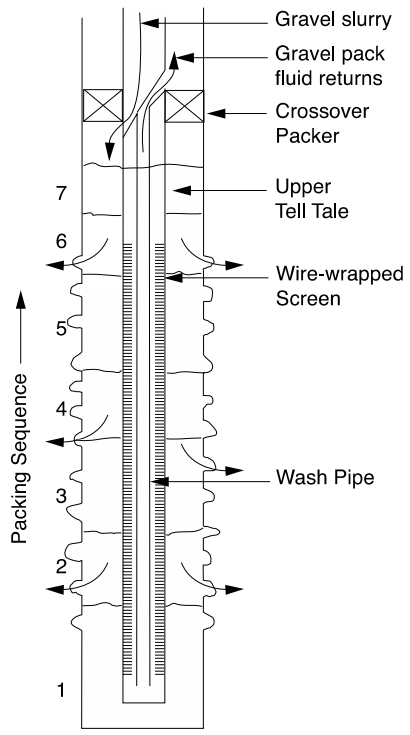

Figure 43 The gravel packing process with low viscosity fluids in near vertical wells.

The process that occurs in the (**horizontal**) perforations – dune formation – is more complicated (Figure 44). The gravel is deposited at the mouth of the perforation since it cannot be held in suspension by the slow-moving fluid (the leak off rate **per perforation** is low). The dune builds up (typically to 70-90% of the opening) until the gap between it and the top of perforation is so narrow that the fluid velocity has increased sufficiently to carry the gravel further down the perforation. The dune can then extend along the perforation the same way until the perforation tip is finally reached as shown. (This process is known as "Saltation" flow. It is similar to that observed in dune movement in deserts or in the movement of sand bars in rivers).

The final stage is packing of the top of the perforation backwards from the perforation tip to the mouth of the perforation. It should be remarked that a similar process is observed when gravel packing long horizontal wells.
The α wave or dune formation packs the 70-90% of the bottom of the wells from the heel of the well towards the toe. The (reverse) β wave then packs the top of the well from the toe towards the heel.

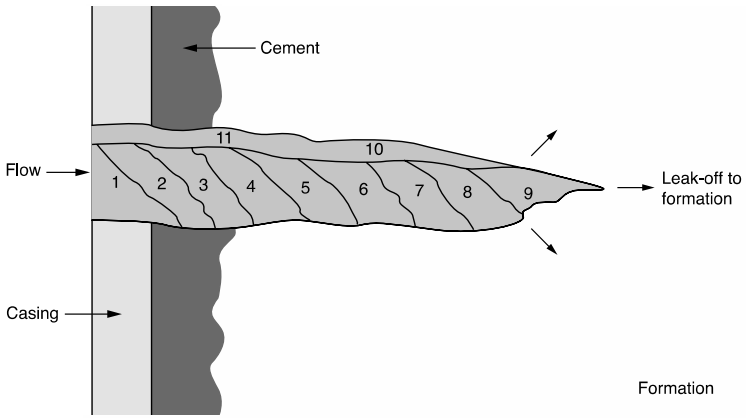

Figure 44 The perforation packing process with low viscosity fluids. Numbers show the chronological order of dune forming.

6.12 Gravel Placement with High Viscosity Fluids

Internal Gravel Packs are usually placed with high viscosity fluids. The high viscosity (up to 300 cp) carrier fluids allow the gravel to be suspended at high gravel concentrations (up to 15lb gravel/gal carrier fluid or 50% vol). Also, the resulting slurry can be pumped at low rates (0.5 – 1.5 bbl/min). This gives considerable advantages which should lead to higher productivity completions:

- Limited fluid volume gives reduced screen plugging
- Low pump rate reduces the gravel/sand mixing

The gravel packing process is quite different with high viscosity fluids:

- Gravel slurry dehydration is initiated at the perforation tip followed by formation of a gravel node projecting into the casing once the perforation is filled (Figure 45). The process is driven by fluid leak off into the formation.

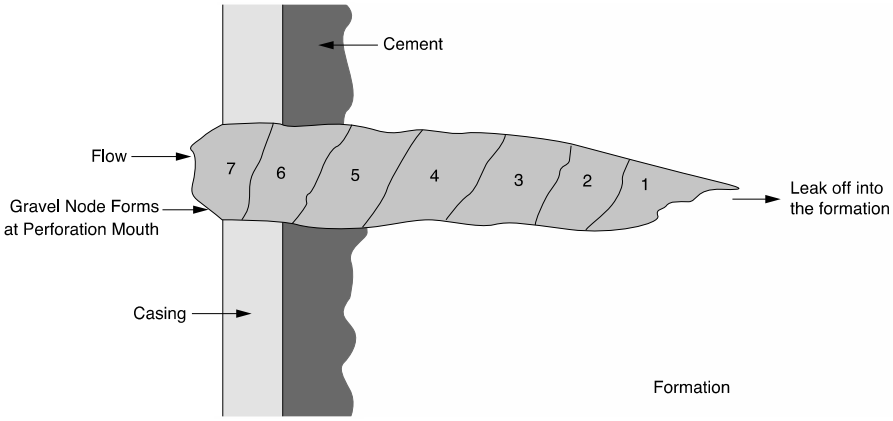

Figure 45 The perforation packing process with viscous fluids.

- Simultaneously, a sheath of dehydrated gravel is formed around the screen – the process being driven by fluid flowing circulating through the screen and returning to the surface via the washpipe (Figure 46).

- The circulation pressure is chosen so that in the ideal case approximately 50% of the fluid "leak-off" into the formation and 50% returns to the surface via the tubing/casing annulus.

- The gravel nodes projecting into the casing and the gravel sheath around the screen are held in place (against the force of gravity) by the force generated by the flow of viscous gravel pack fluid through the perforation "leak-off" into the formation and flowing into the screen/wash pipe annulus respectively.

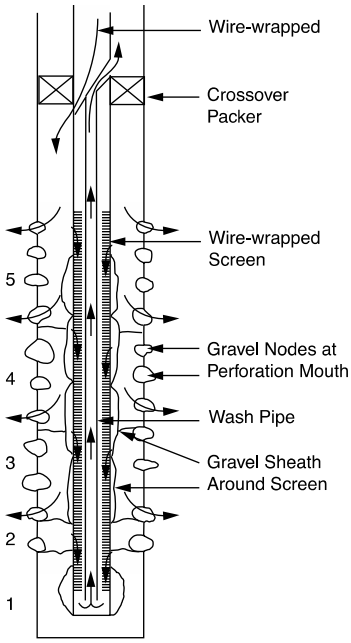

Figure 46 The gravel packing process with viscous fluids in near vertical wells.

- The remainder of the gravel pack is then completed from the bottom upwards (Figure 46). The pressure increases rapidly once the gravel pack is completed as far as the top of the wire wrapped

screen. A screen out has been achieved.

- The cross-over tool is raised to allow circulation directly from the casing-tubing annulus into the tubing. The excess gravel slurry is recovered by reverse circulation in a similar manner to that used for low viscosity fluids.
- A chemical breaker **must** be mixed with the viscous fluid to degrade the viscosity so that production may be established once the gravel pack operation is complete.
- Production may be started once the completion is installed.

More difficulty is experienced in obtaining complete gravel packs when:

- The completion interval contains large permeability contrasts
- The completion zone is long (> 15 m)
- The deviation angles are high (> 50°)

Techniques and computer design programs have been developed to efficiently gravel pack long horizontal wells. Special equipment is now available for gravel packing such wells. For example, large diameter wash pipe forces the slurry to flow to the bottom of the well and "Alternate Path" or "Transport Tubes" shunt tubes installed on the outside of the screen allow the gravel to bypass a gravel bridge formed in the screen/casing annulus as was mentioned.

7. CHEMICAL SAND CONSOLDIATION

Chemical sand consolidation – the artificial strengthening of the oil/gas producing formation – is the least frequently used form of sand control. This is despite its two major advantages:

- Unlike mechanical forms of sand exclusion, it leaves the wellbore completely unobstructed without imposing any restrictions as far as future work-overs are concerned (similar to a standard perforated completion)
- The consolidation treatment can also be carried out through tubing i.e. a drilling or work-over rig is not required and the tubing etc. does not have to be pulled as the first stage of the well repair. Instead, a pump truck and a series of chemical storage tanks with suitable manifolding have to be provided. This can often be mobilised more quickly and at a lower cost than a drilling or work-over rig.

The chemical glue must:

- Wet and adhere to the sand grains
- Leave the pore spaces open so that the permeability is retained.

This is illustrated in Figure 47 which shows an enlarged view of a number of sand grains which have been covered with chemical cement. Organic resins (epoxy, furan or phenolic) are the most widely used chemical cements, though other materials have been used in the past.

The typical target formation for chemical consolidation are thin (< 3 m), high permeability, clean (low clay content) sands. This restriction on the formation type to be treated and the operational complexity explains the lack of popularity of chemical consolidation.

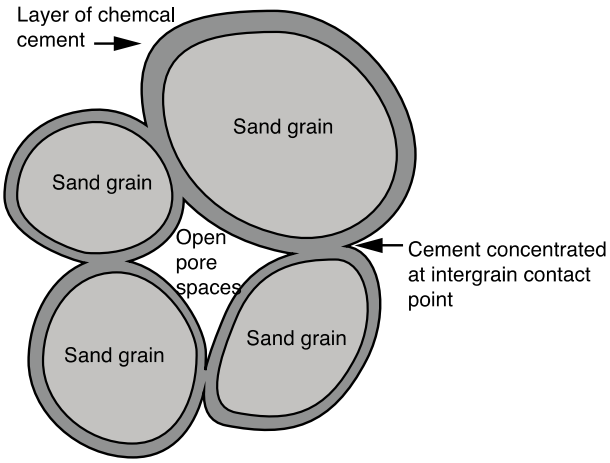

Figure 47 An enlarged view of a chemically consolidated formation.

All the chemical flushes have to be applied to **all** the perforations in the correct order since one or more incorrectly treated perforations could lead to future sand production. Field experience has shown that this requirement for correct **placement** means that only thin zones (maximum length 3 m) should be treated at one time. Longer zones require a series of consecutive treatments.

> *Feel free to attempt Tutorial 3*

8. RECOMMENDED READING

1. "Production Operations", Volume 2, 4th Edition, by Allen, T., and Roberts, A., OGCI, 1993
2. "Petroleum production Systems" by Economides M., Hill A. & Economides C.; Prentice Hall, 1994.
3. "Well Performance" 2nd edition by Golan M. & Whitson C.; NTNU,1996.
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5. "Well Completion Design" by Bellarby, J., Elsevier, 2009
6. "Sand Control. SPE Series on Special Topics.", Volume 1, by Penberthy, W.L., and Shaughnessy, C.M.; SPE, 1992

CHAPTER 11: FIELD DEVELOPMENT CONCEPTS AND FLUID PROCESSING

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LEARNING OBJECTIVES

(All Examinable)

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

- Explain oil and gas field development concepts
- Describe and compare the facilities required for production of hydrocarbon reservoirs
- Discuss why Gas and Oil facility designs differ
- Describe the various functions found on a production platform
- Describe the components and discuss the operation of a 3-phase separator
- Describe the operational problems associated with the separators
- Quantify the sizing (gas and liquid capacity) of a 3-phase separator
- Discuss fiscal measurement of produced crude oil
- Describe a pipeline "pigging" operation
- Describe the components and principles of a gas handling facility viz compression, NGL separation and stabilisation, gas dehydration and sweetening.
- Describe the methods used to treat oily water separated by the primary gravity separation equipment (corrugated plate interceptor, flocculation, coagulation, (gas) flotation, hydrocyclones, and coalescers)
- Outline the processes required to "clean up" water for water injection

1. INTRODUCTION

So far this course has covered much of the subsurface engineering solutions used to improve hydrocarbon production to surface. However, Production Technology skills would be incomplete without having a notion of what happens to the fluids at the surface (i.e. a notion of process engineering). The surface processes quite often define the limits of the well or field production, and influence the well subsurface management strategy. This chapter briefly covers the layout of the surface production facilities required to process the produced fluid during its passage from the well-head to the point of sale. These facilities differ for oil and gas fields. So the chapter first discusses the field development strategies for oil and gas fields, followed by a brief overview of offshore production facilities (platforms and ships). The basics of gas/oil/water separation followed by the gas and water handling principles conclude this chapter.

2. FIELD DEVELOPMENT CONCEPTS

The nature, scope and geographical spread of the surface production facilities will vary greatly depending on the:

- Location: On or Off-shore
- Types of field development: oil, gas or condensate field
- Well and Field Production Rates
- Temperature, pressure, and fluid composition of the produced fluid
- Central gathering station or local (well-head) facilities
- Secondary processing requirements e.g. removal of components such as H_2S

➢ *Feel free to discuss how these conditions may affect the facilities: their size capacity, objectives, challenges…*

However, in all cases the facility is designed to separate the (multi) well stream into the three basic components (oil, gas, and water) and to process these phases into:

- Marketable products (i.e. to sales specification) – or
- Fluids and solids that can be disposed of in an environmentally acceptable manner.

2.1 Oil Fields

The oil field's production daily rate is built up as rapidly as possible by drilling and producing more wells once first oil production has started (Figure 1). The oil field is then produced at a maximum production rate (the 'plateau' phase) for as long as possible (the field is still commonly considered 'green' at this stage). This rate is determined by the capacity of the production and export facilities. It is important neither to oversize (resulting in a higher investment not matched by the field production), nor undersize the facilities (resulting in the facilities severely limiting the field production), which is quite challenging given the facilities are designed when there is limited, uncertain information about the field's STOOIP and productivity. The facilities are often designed to allow annual oil production of certain proportion of the oil reserves, e.g. 10-15 %.

The oil production rate then gradually decreases (the field turns 'brown' or mature), however in most cases this does not mean the overall production rate decreases (Table 1). *(On the contrary, in water flooded reservoirs the watercut and the liquid production rate will be increasing with time. For this reason, the global Oil Industry today produces over 3 barrels of water for each barrel of oil.)* Infill drilling, improved and enhanced oil recovery techniques, and production optimization will be used to maintain the oil production rate as high as possible during this oil production decline phase. Eventually the income from the oil production no longer pays for the field operating expenses (Figure 1). The field is then ready for decommissioning and abandonment.

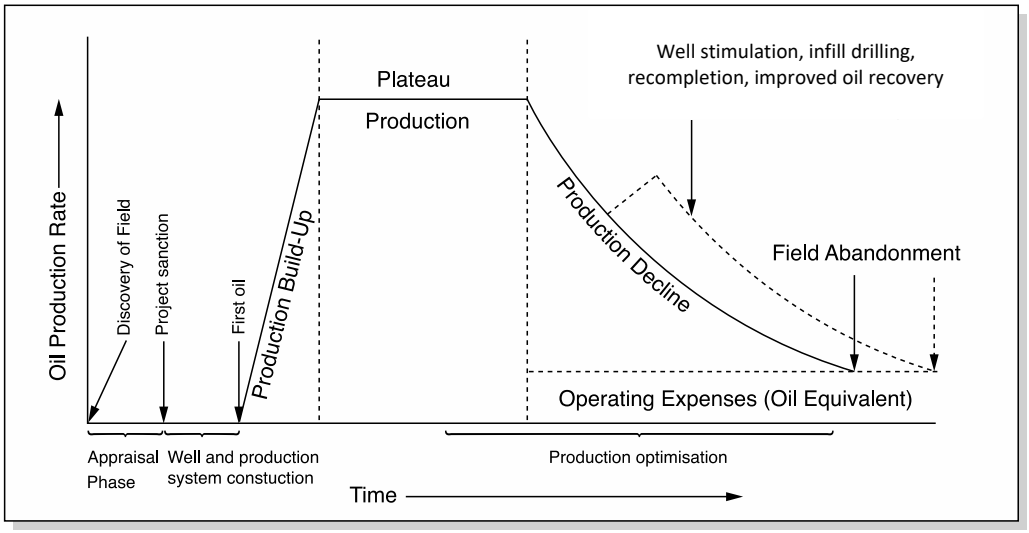


Figure 1 A typical Oil field production profile.

Phase / Fluid	Early	Mid-Life	Mature	Abandonment
Oil (bopd)	100,000	100,000	30,000	10,000
Gas (MM sft^3/d)	100	100	30	10
Water (bwpd)	< 500	30,000	100,000	> 100,000
Water cut	< 0.5 %	30 %	77 %	> 90 %

Table 1 Typical changes in production rates during the lifetime of a medium-size oil field.

The production facility capacity and thus the design plateau oil production rate will be determined by the expected individual well rates and the numbers of wells drilled; as well as by the reservoir's geology and fluid properties, the company's economic requirements, etc. The length of the production plateau (typically a few years for medium-size reservoirs) and the decline rate will also be a function of the reservoir size and the recovery mechanism.

As mentioned, typical oil fields will eventually produce a much larger volume of water than oil. Hence, oil/water separation typically occurs near to the production well to minimise unnecessary expense in the pumping of large volumes of water over large distances. For instance, offshore separation on a platform or on a production vessel will be employed in the case of offshore fields; on-site separation for onshore fields; while wellhead separation (at the sea floor and disposal into an injection well) is sometimes an option for subsea wells. Offshore operations are thus becoming more similar to land operations, where piping and pipeline costs are minimised by:

- Local separation and disposal of the bulk of the produced water
- Oil (with a relatively low water content) being sent to a central gathering station (or central processing unit CPU) for final water separation treatment

Large volumes of sales-quality crude oil are piped to the coastal export terminal via a pipeline where it can become part of the world crude oil trade. This is particularly true for onshore oil fields where the only economic means of transporting significant volumes is by pipeline, though smaller volumes are sometimes transported by train, river barge, or road. Offshore, the choice between a pipeline and local storage near the platform together with a shuttle tanker to transport the crude oil directly to the refinery or export terminal will be determined by the economics of the two scenarios. If a dedicated pipeline to the coast cannot be justified, then the presence of existing infrastructure (a nearby pipeline) with sufficient available capacity to transport the projected volumes is the key factor.

Gas export is normally only possible when the volumes are sufficient to make building of a dedicated pipeline economic. Thus, the available pipeline infrastructure is even more important in the case of produced gas since there are no storage alternatives – it has to be exported and/or used and/or disposed of at the same time as it is produced, e.g. injected in the gas cap, an underground aquifer, or a depleted reservoir provided they can contain it without leaks. Continuous gas flaring is generally no longer legal due to the governmental objective of reduction in the emitted (flared and vented) gas, with some countries imposing a carbon tax and/or quotas on the volumes of emitted carbon dioxide. *Temporary gas flaring, e.g. during extended well testing of an appraisal well, may be viewed differently.*

Alternatives to pipeline export of produced gas, such as floating facilities for liquefied natural gas or compressed natural gas, require very capital-intensive facilities; hence very large volumes of gas reserves. Smaller volumes of gas can be used for electrical power generation for the local market if a local consumer gas market does not exist.

Many oil developments will use (part of) the gas as a fuel to power the platform and facilities. However, the changes in the volumes of produced fluids from the wells (Table 1) imply that there may be excess gas early in the life of the project available for use and/or export, while the platform becomes gas-short later on in the project lifetime. The installation of a gas pipeline thus allows the field to export gas in the early years as well as import gas to power platform equipment later in the project's lifetime. This is particularly attractive if the operators own a nearby field with surplus gas.

All these factors have a large impact on the design of the platform facilities.

As mentioned earlier, large volumes of water are "co-produced" with the oil. Waterflood recovery mechanism is often used: large volumes of water are injected into the reservoir to increase the oil recovery by "sweeping" the oil from the injection to the production wells, and by maintaining the reservoir pressure.

This requires facilities to:

- Extract large volumes of water from a surface (sea or river) or underground source (dedicated water production wells)
- Remove solids (by filtration) and (corrosive) oxygen to the specified levels and
- (Re-)Inject the water into dedicated injection wells.

2.2 Gas Fields

The development of a hydrocarbon resource such as a gas field implies that, unlike oilfields, the produced fluid will be mainly gas accompanied by small volumes of water, as well as condensate. {The condensate – light hydrocarbon liquid, is also called "natural gasoline" or natural gas liquids (NGL)}. NGLs are more precious compared to gas, so their extraction prior to gas export is often one of the priorities. The fraction of NGL in the gas varies depending whether it's a dry gas, lean gas, wet gas, or gas condensate field.

High Temperature, High Pressure Gas Condensate fields are also being developed. These fields produce (relatively) much larger volumes of NGLs, or condensate, compared to gas fields. They also exhibit unusually large changes in reservoir and wellhead pressures and the composition of the produced fluid as the reservoir depletes.

Gas sometimes can be stored in underground reservoirs or liquefied, but more commonly it has to be used as produced. The pattern of gas usage tends to be seasonal i.e. with periods of high and low demand, e.g. winter peaks in colder countries (for heating) or summer peaks in hotter ones (due to air-conditioning powered by gas electro stations). A typical nomination contract specifies both a total yearly production volume to be supplied and a minimum production rate during the demand season.

The composition of the produced water will change significantly during the field's life time. Initially it will be (fresh) condensed water vapour that was originally present in the gas phase in the reservoir. (Liquid) formation water will be produced from the reservoir later, resulting in a gradual increase in the produced water's salinity until the water produced at the surface equals that of the formation water salinity due to large-scale water production occurring.

A typical production profile is illustrated in Figure 2 and Table 2. Liquid loading in watered gas wells is common, resulting in the wells ceasing production earlier. The fast decline is also due to the gas fields often being produced in the depletion mode (i.e. without water or gas injection for pressure maintenance).

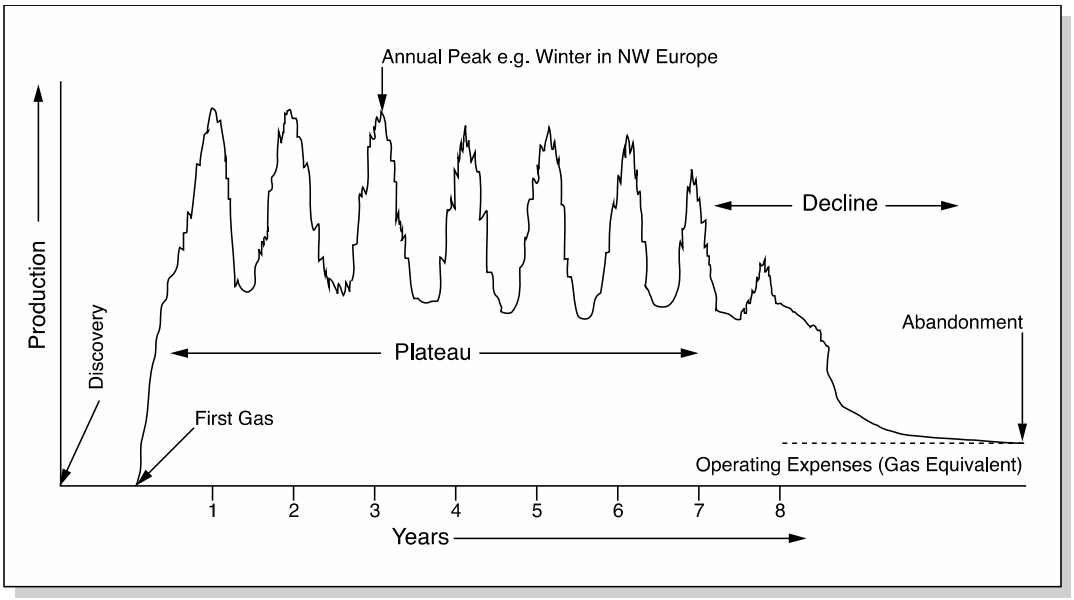


Figure 2: A typical gas field production profile.

Fluid \ Phase	Early	Mid-Life	Declining	Abandonment
Gas (MM sft^3/d)	500	500	50	20
Condensate (bpd)	5,000	5,000	500	200
Water (bwpd)	250	500	500	200

Table 2 Changes in the volumes of produced fluids from a typical Southern North Sea gas field.

3. OFFSHORE PRODUCTION FACILITIES

Various designs for a platform are available (Figure 3). The choice depends on the water depth, the local met ocean conditions and the field's plateau production rate. Once the choice is made, the detailed design will be determined by the field's location, water depth, the reservoir fluid properties, the problems expected during production, etc. Great attention is paid to the economic analysis of the various production facility options so as to maximise the field's expected Net Present Value (NPV); taking into account the range of production scenarios that may occur due to the uncertainty in the available geological and reservoir data.

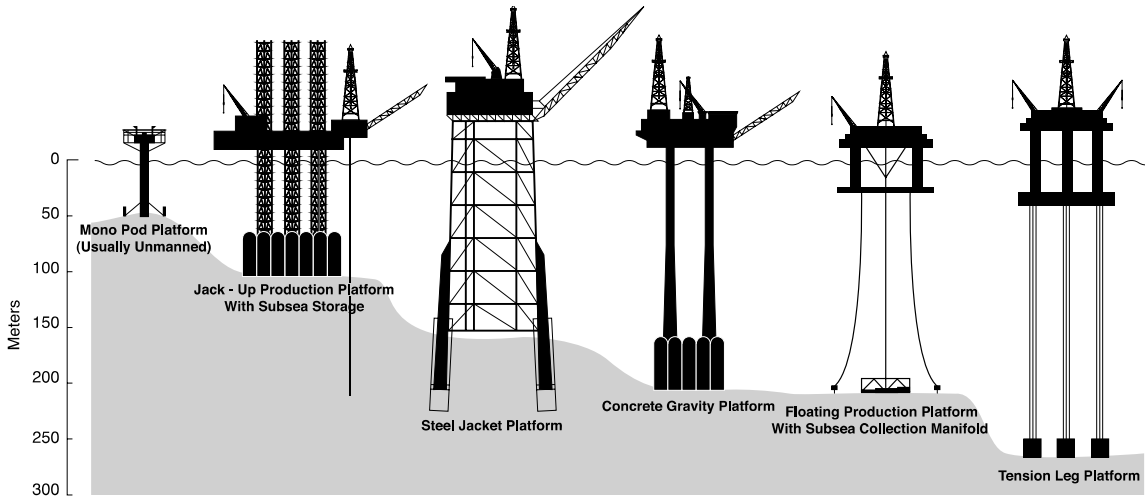


Figure 3 Some of the available offshore platform designs and the (in general) maximum sea depth they can be installed in.

The majority of offshore production platforms are supported by steel jackets which are held in place on the sea bottom by steel piles (Figure 4). This large, integrated steel jacket platform has a welded pipe sub-structure that provides support for various prefabricated top-side modules ('top-sides'), e.g. used for accommodation, power facilities etc. Such platforms typically can support the weight comparable to their own.

Figure 4 An integrated steel jacket platform. *Note there are usually several levels (decks) on a platform, with the wellheads (if dry) located at the lowest, 'cellar deck' while the top deck is the 'helideck' for helicopters.*

Concrete gravity platforms depend on their large weight to hold them in place on the seabed. For example, the Brent D platform weighs over 200,000 tons, but is also capable of storing 1,000,000 barrels of oil. This provided local crude storage capacity for transfer at regular intervals to shuttle tankers via a single buoy mooring (SBM) prior to the construction of the oil export pipeline.

Fixed production platforms like steel jacket or gravity ones have the deck well above (at least several meters above) the sea level to stay above waves. At the sea depths of 1500 ft or more such fixed production platforms become too expensive and less stable (due to high bending loads). At such depths floating facilities can be used e.g. semi-submersible platforms (with ballasted pontoons below the sea level) or ships. For instance, a tension leg platform (TLP) is tethered in place by several cables and tubes (tendons) anchored or piled at the seabed.

As for the ships: the most recent developments to exploit the smaller hydrocarbon reservoirs currently being developed, can be found in the combination of subsea wells drilled from one or more drill centre (often with a subsea 'template': a metal structure with slots for wellheads and a manifold, installed at the seabed) with a Floating Production Storage and Offtake (FPSO) vessel. The FPSO hosts all the normal platform functions such as production separation and water injection equipment. It can be anchored in place or dynamically positioned in place by a satellite navigation system and propellers (thrusters) on each side.

A floating storage and offtake (FSO) vessel can be used if oil storage is not available within the platform itself. The oil is then exported from the FSO to a shuttle tanker. Offshore storage or loading from a single buoy mooring is illustrated in Figure 5. Alternatively, a storage tanker can be used and an offloading buoy.

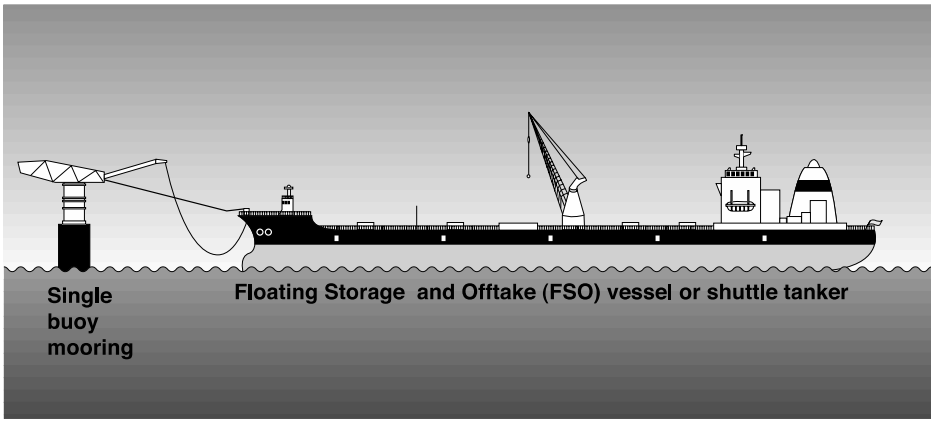


Figure 5 Offshore storage or loading of oil from a Single Buoy Mooring.

As discussed earlier, gas export requires a pipeline while oil export can be by pipeline or shuttle tanker. Figure 6 illustrates a typical example of this type of development. An FPSO is not the only option for this type of development – a fixed platform can provide the host production facilities for production from multiple, subsea oil fields (Figure 7).

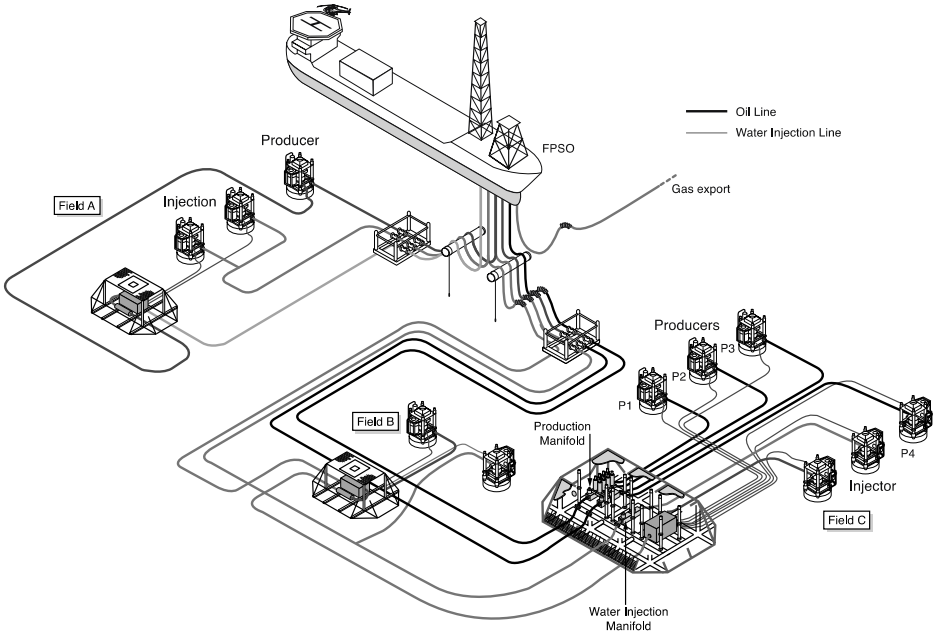


Figure 6 A multi-field, subsea (tieback) oil development supported by FPSO.

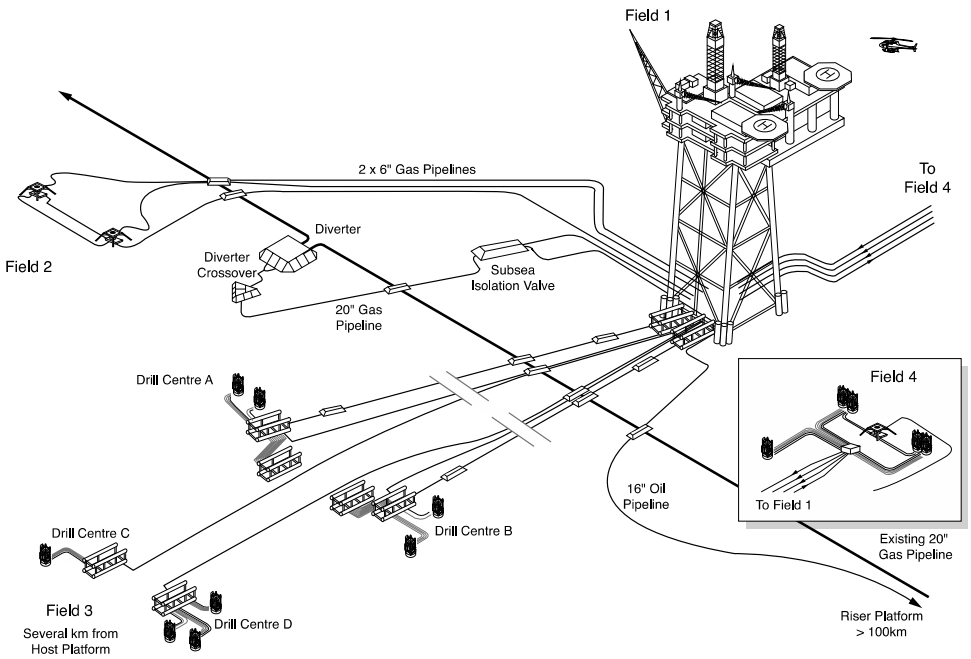


Figure 7 The host platform developing Field 1 is also connected to several (satellite) subsea fields.

3.1 Production Platform Functions

Production platforms perform a multitude of functions as listed below. All functions may be carried out on one large platform - as in the case of integrated platforms illustrated in Figure 4. Figure 8 illustrates an integrated platform's component modules.

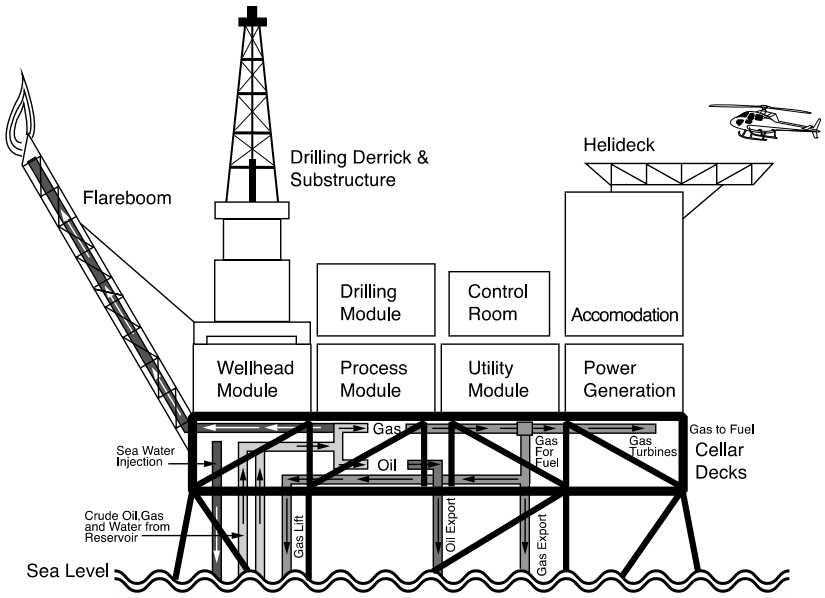


Figure 8 An integrated steel jacket platform.

1 **Drilling derrick** with wellheads situated directly underneath
2 **Drilling support** module e.g. as pipe handling, drilling mud preparation, pumps, chemical storages etc.
3 **Process equipment** where oil, gas and water are separated and treated to sales pipeline specifications. This also covers:
   - Gas compression: Gas is compressed to the required pressure for export or own use (gas lift, gas injection or power generation). Excess gas can be flared via the flare boom where allowed.
   - Oil export: The pumps for exporting the crude to pipeline, local (floating) storage or shuttle tanker are placed here
   - Water Injection: Comprising of filtration, deoxygenation, chlorination, and high-pressure injection pumps
4 **Platform utilities** such as power generation. Electrical power generation frequently employs gas turbines, but stand-by diesel power is also required for when the gas supply is not available
5 **Accommodation/life support** for the platform personnel. This is normally situated as far as possible from the process/compression/wellhead areas for safety reasons
6 **Control room**: This is the hub of the platform's operation. Safety and loss control systems are monitored here; as is the fiscal metering that accurately measures the volumes of crude oil and gas exported and imported
7 Other **Utilities** like **Maintenance workshops**, communications, cranes to lift supplies and equipment onto the platform from supply vessels, transport (helicopters) etc.

The multi-module arrangement shown in Figure 8 is used when single lift crane capacity of off-shore heavy lift barges is limited. The lift capacity of floating cranes has now increased to more than 10,000 tons, allowing the on-shore construction and testing of the complete integrated deck. This not only reduces the amount of (costly) offshore construction work, but also reduces the number of lifts.

The platform functions are not always integrated in a single platform; but may be separated into multiple separate platforms connected by bridges (Figure 9).

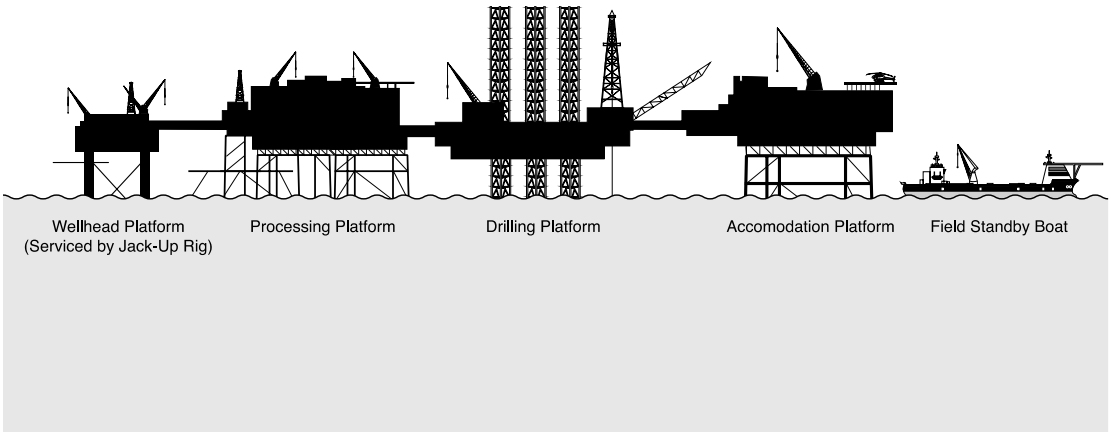


Figure 9 illustrates a series of 4 separate platforms with their functions.

The chosen Reservoir Oil Recovery Mechanism and associated artificial lift used to increase the energy available to lift fluids from the downhole to the surface will have a significant impact on the required (platform) services (Table 3).

Recovery Mechanism	Process		Impact
Primary Recovery	Natural Flow	-	No extra platform services
	Artificial Lift	Gas Lift	Extra Gas Compression
		ESP*	Extra Electrical Power Generation
Secondary Recovery	Water Flood		Water Injection Facilities
	Pressure Maintenance	Water injection	Water Injection Facilities
		Gas injection	(High Pressure) Gas Compression
Tertiary Recovery	Steam, Carbon Dioxide, Miscible Gas, Chemical etc.	Dedicated, Specialised Facilities Most techniques have only been applied on land	

* ESP - Electric Submersible Pump

Table 3 The scale and type of platform services depend on recovery mechanism.

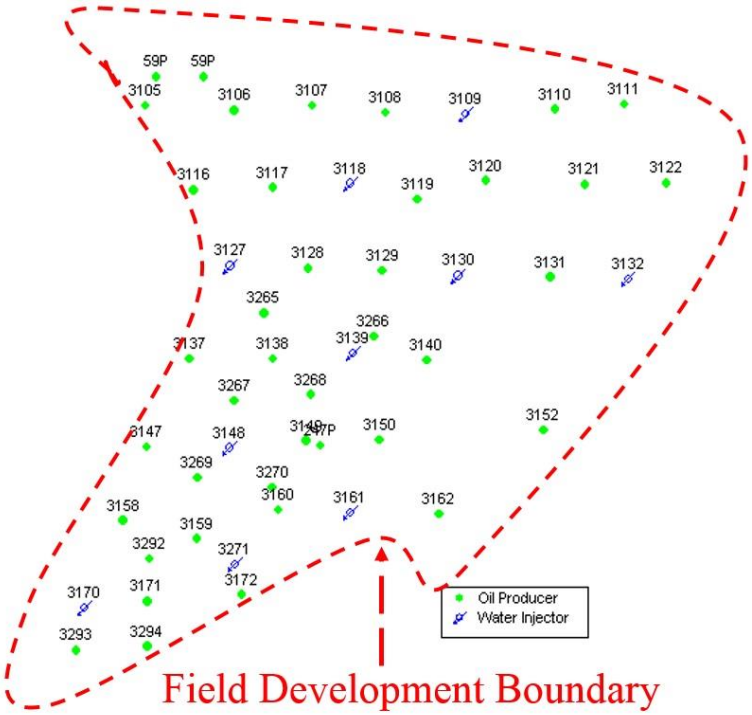


Figure 10 Field Development on Land with Regularly Spaced Wells

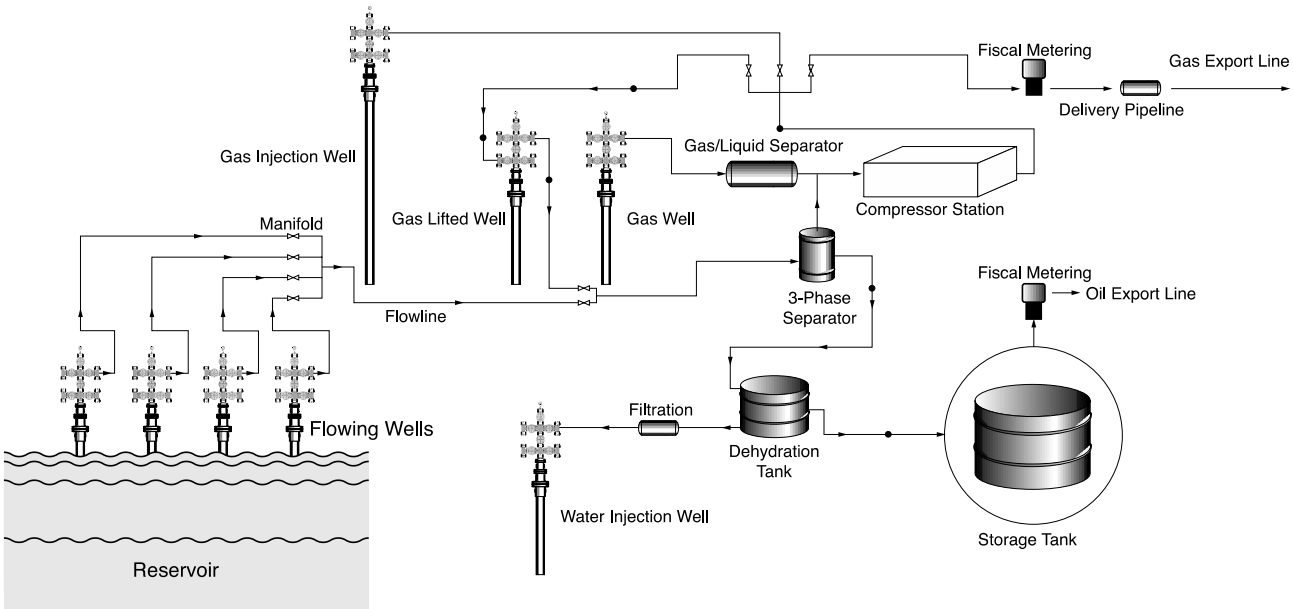


Figure 11: A schematic diagram of typical land production facilities

On-land, the wells are often placed closer together in a regular pattern since both the cost and production rate per well are much lower than encountered offshore (Figure 10). Production facilities with the same objectives as those installed offshore are employed on land, but without the space and weight limitations that are encountered offshore.

Generally, the most economic option is to install all the required facilities during the initial field development. However, incremental development through a series of phases can often be a low-risk approach that minimise the total capital expenditures required for the development.

3.2 Production Facility Planning Options

Part of the field development process is to review the economic merit of various options for field development. Typical facility-related options that may be studied are to:

1. Build a New Platform
2. Install a Subsea Tieback to a nearby host facility
3. Lease of FPSO vessel
4. Purchase of FPSO vessel

The plans are outlined below.

Option 1: A purpose-built Platform

A new platform involves high capital expenditure. The platform maximum oil capacity, or plateau rate, will be evaluated through reservoir simulations and economic analysis of the resulting production profile. All the facilities will be new and purpose-built for the specified production fluids and their production rates; hence it is to be expected that any down time will be minimal.

Managing process facilities and wells is much easier and more efficient from a purpose-built, permanent platform structure. Oil and gas export could either be via another platform or tied back into existing oil and gas export pipeline. Table 4 summarises the key advantages and disadvantages of this option.

Advantages	Disadvantages
• Optimally designed for the required production rates • Low operating costs • Cheaper infill drilling, regular well interventions • Maximises reserve recovery • Potential for field expansion through subsea tieback • Small relatively nearby development targets that can be reached by extended reach drilling from the platform can also be developed	• High capital expenditure • NPV is reduced by the long platform construction period which defers first oil production • Field abandonment costs must be included in the project's economic evaluation

Table 4: Advantages and Disadvantages of building a new platform

Option 2: A Subsea Tieback to a nearby host facility

A subsea tie-back as a satellite field connected to a FPSO or a platform that is already present in the area, is another field development option. All produced fluids are exported to the host platform or FPSO. The marketable oil and gas are then exported by the existing evacuation route. The resulting additional processing fees to the host facility must be included as an increased operating cost when evaluating the project's economics. Similarly, the host facility's reliability and the time period over which it will be available must also be included. Table 5 summarises the key advantages and disadvantages of this option.

Advantages	Disadvantages
• Lower capital outlay, faster start-up and earlier first oil • Lower decommissioning cost for subsea templates and wells than for a dedicated platform	• Operating cost will be higher due to processing fees levied by the host facility • Capital investment required to adapt the host facility's production equipment (separators, etc.) to be able to process this new, production stream • Liable for contribution toward the host facility's decommissioning costs • Production rate may be limited by the host facility's capacity constraints • The recovery factor may be reduced by early decommissioning of the host facility • Higher cost for interventions and work overs • This higher cost and lower frequency of interventions and work overs for subsea wells limits the production improvement potential and thus reduces the oil recovery/reserves (Figure 12)

Table 5: Advantages and Disadvantages of subsea well tieback to a host production facility

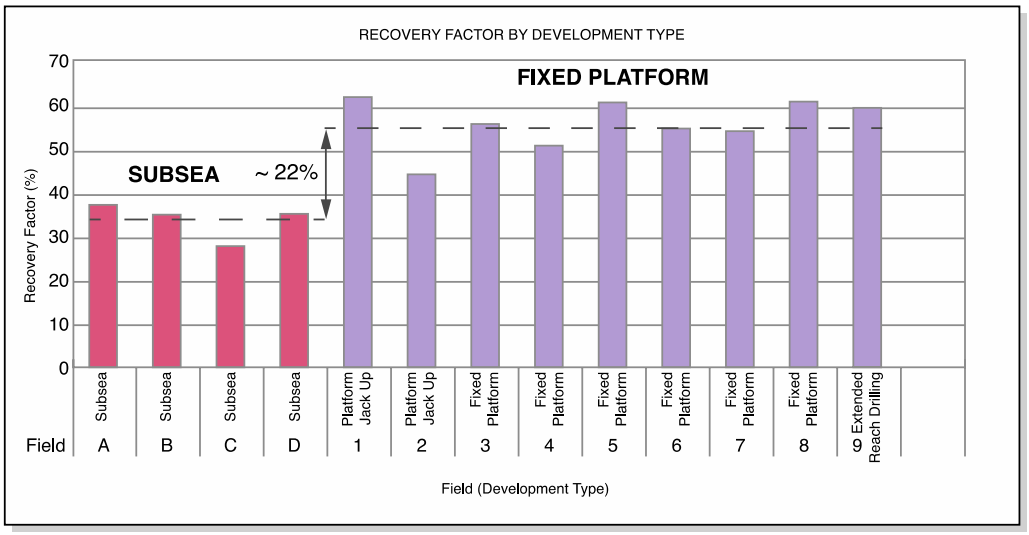


Figure 12 Comparison of oil recovery factors in several fields developed by subsea wells or fixed platforms

➢ *Feel free discuss the reasons for the recovery factor differences in Figure 12.*

Option 3: Subsea wells with Leased FPSO Vessel

Lease of a FPSO vessel for developing the field is one of the viable options. The oil may be exported by pipeline or tanker, but governmental project sanction will only be given on the condition that gas is exported (continuous gas flaring is not permitted) or stored underground. The FPSO must export the gas by pipeline either to another platform or to a direct tie-back to an existing export pipeline. Gas processing to pipeline quality is handled by the FPSO. Table 6 summarises the key advantages and disadvantages of this option.

Advantages	Disadvantages
• Lowest CAPEX requirement of all options if oil export is via shuttle tanker • Early first oil • Reduced financial risks during periods of low oil prices because of the reduced CAPEX requirement • Lowest decommissioning cost (the vessel can be easily removed when the field is decommissioned)	• FPSO will require modifications to process the field's produced fluids. May be charged as an increased day-rate rather than a capital charge • Highest OPEX of all options. This will cover the day-rate charge for the FPSO, manpower, as well as production and management services. Operators also pay a charge per barrel of oil and cubic foot of gas processed by the vessel. • Higher OPEX per barrel of oil produced due to the higher shuttle tanker cost compared to pipelines.

	• Higher cost for interventions and work overs for subsea wells reduces the oil recovery/reserves • Limited oil storage capacity, typically between two and seven days production at maximum field rates. • Lower production up-time; FPSO operations are more weather dependent (e.g. for oil offloading)

Table 6: Advantages and Disadvantages of leasing a FPSO

Option 4: Subsea wells with purpose-built FPSO Vessel

The advantages and disadvantages of this option are as follows:

Advantages	Disadvantages
• High CAPEX requirement if FPSO is operator financed • FPSO may be financed and operated by a third-party who recover their costs via the day-rate of a fixed term contract (reduces CAPEX but increases OPEX), not 3rd party rental charges for FPSO vessel • More efficient processing and reliability due to installation of fit-for-purpose process facilities • Low decommissioning cost (the vessel can be removed to another field or sold)	• Increase CAPEX requirements - possibly similar to a platform • Probable delay in first oil due to need to modify/build own FPSO • Higher OPEX per barrel of oil produced due to the higher shuttle tanker cost compared to pipelines. • Higher cost for interventions and work overs • Reduced recovery/reserves due to subsea wells development with their accompanying high intervention costs • Limited oil storage capacity, typically between two and seven days production at maximum field rates. • Lower production up-time; FPSO operations are more weather dependent (e.g. for oil offloading)

Table 7: Advantages and Disadvantages of leasing or owning a purpose-built FPSO

4. BASIC OIL FIELD PROCESSING SCHEME

Figure 13 illustrates a simplified production scheme for an oil or gas field.

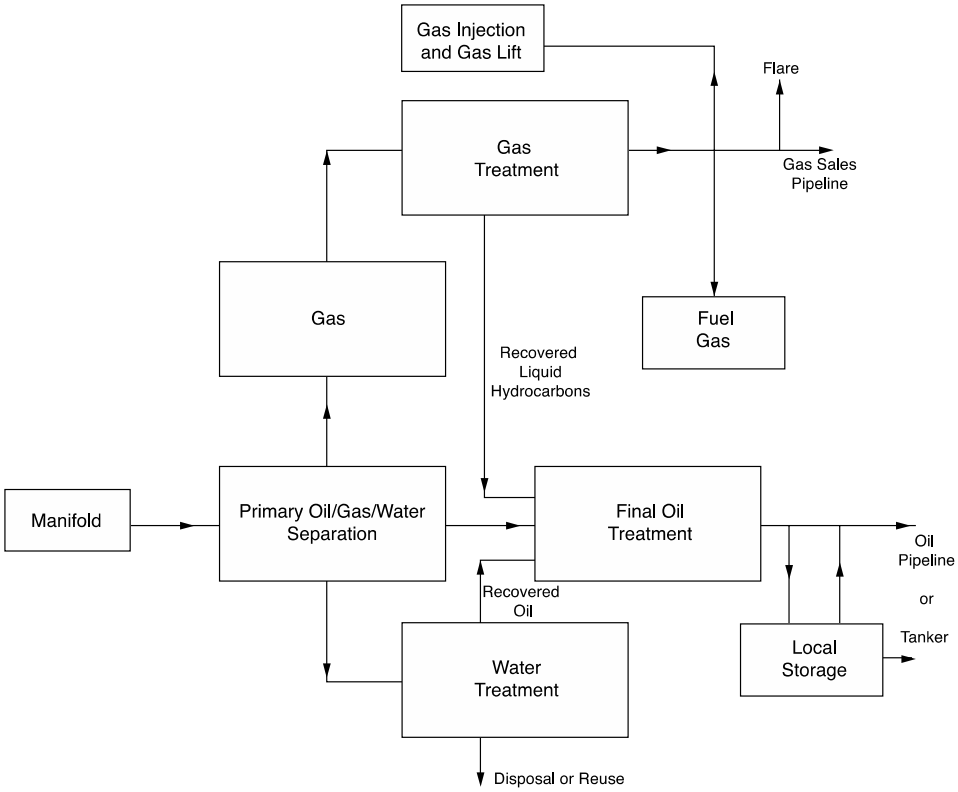


Figure 13 A basic oilfield process scheme.

The primary separation process takes place in gravity separators. The process is driven by the density difference between the gas, oil and water phases; and the high fluid pressure frequently available at the well head. Gas "flashes" from the well-head fluid as the pressure is reduced, while at the same time "free water" is separated from the oil.

The gas must be compressed to the export pipeline pressure and treated to remove water vapour (by gas dehydration) and heavier hydrocarbons (by NGL recovery). More complicated processes may be required to "sweeten" the gas by reducing concentration of carbon dioxide and hydrogen sulphide.

Typically, the oil and water phases will only partially separate with an emulsion (a mixture of oil or water: one phase dispersed as droplets in the other) requiring more intensive processing to achieve the required level of separation. Once the oil has been processed to market specification it is either exported via pipeline or stored locally prior to export and sale via the chosen evacuation route.

The separated water passes through further treatment stages to remove dispersed oil and solids so that the water meets the specifications required for reuse (water injection) or for disposal.

The complete separation process system is designed to produce on specification export fluids. The actual values will depend on the specific (crude oil or gas) properties and the transport route (Table 8).

PRODUCT †	PROPERTY	SPECIFICATION
CRUDE OIL	Vapour pressure	< 16 psi at 25° C *
	Water content	< 0.5% wt
	Salt content	< 70 g/m^3
	Temperature	< 40° C
	Pressure	~ atmospheric pressure for tanker export or pipeline operating pressure
	* Higher values allowed for pipeline export	
GAS	Calorific Value	~ specified limits
	Liquids	- none
	Hydrocarbon Dewpoint	< -3° C at 70 bar
	Water Dewpoint	< -8° C in NW Europe
	Carbon Dioxide	< 3% wt
	Hydrogen Sulphide	< 5 ppm
	Temperature	< 40° C
	Mercury	< 5 ppm
	Oxygen	< 0.5%
	Nitrogen	< 1%
	Pressure	~ pipeline operating value
	* varies with ambient conditions e.g. 0° C in sub-tropical areas, -20° C in Canada	
WATER	Dispersed oil	< 30 ppm average for marine discharge in N.W. Europe, < 32 ppm in Gulf of Mexico

† Crude oil density, viscosity and sulphur, wax and asphaltenes contents, all depend on the source of the crude oil

Table 8 Typical sales/disposal specifications.

The fluid quantities, quality and properties expected **over the production life** generally define the design of the processing facilities.

Hydrocarbon mixtures can be classified into five main types based on their phase equilibria properties (Table 9).

Hydrocarbon type	Low Shrinkage Oil	High Shrinkage Oil	Retrograde Condensate	Wet Gas	Dry Gas
Field Development type	Oil reservoir	Oil reservoir	Oil reservoir	Gas reservoir	Gas reservoir
Stabilised crude density	< 30°API	30° < API < 50°	API < 60°	API > 50°	API > 50°
Gas Oil Ratio (sft^3/bbl)	< 500	500 < GOR > 8,000	< 70,000	< 100,000	> 100,000
Comments	Broad phase envelope with high proportion of high molecular weight hydrocarbons	Narrow phase envelope with few high molecular weight hydrocarbons	Even lower density and fewer high molecular weight hydrocarbons		

Table 9 Types of Hydrocarbons produced.

As an example, typical properties of stabilised crude oil produced by the different North Sea fields are presented in Table 10.

Property	Value
Specific Gravity	0.84 g/cm or 36° API
Viscosity	4 cSt at 50° C
Sulphur content	< 1.0 % wt
Gas Oil Ratio	1000 scf/stb
Crude Oil Composition	50% wt paraffins 30% wt napthenes 20% wt aromatics
Wax	variable, but usually low (< 5%)
Asphaltenes	variable, but usually low (< 2%)
Gas Composition	> 80% methane

Carbon Dioxide and Hydrogen Sulphide in the gas phase are also normally low.

Table 10 Typical North Sea crude oil properties.

➢ *Feel free to discuss the formation damage and flow assurance problems associated with such crudes.*

The hydrocarbon fluid properties along with the wellhead pressures determine the number of separation stages and the process conditions under which the oil/gas/water separation is carried out.

Similar crudes developed from the many fields can be piped to the coastal terminal in a "common carrier" pipeline. The lower the specific gravity (or the higher the API gravity), the greater the market value of the crude due to the increased yield in high value, refined products (light hydrocarbons). Economics thus dictate that denser, more viscous, lower API gravity crudes have to be exported separately via a shuttle tanker, even when a "common carrier" pipeline with sufficient free capacity is available. This is to protect the value of the other crude streams using the pipeline since their value would be reduced on mixing with the high-density crude oil.

Quite often the field production rate can be limited by the efficiency of the fluid transport and/or a processing element. E.G. the gas dehydration unit operates at its maximum capacity which limits the production, or the main pipeline (a.k.a. 'header' or 'trunk line') connecting the manifold to the gathering station is too small to throughput the higher fluid rate. Identification of such 'bottlenecks' and further 'debottlenecking' can be a challenging task in a complex process flow system.

4.1 Process Plant Metallurgy

Maximum producing wellhead temperature and pressure along with the presence of corrosive components (e.g. carbon dioxide, hydrogen sulphide, saline formation waters) determine the specification (metallurgy) of the process equipment. Process conditions can be modified so that a more economical construction metallurgy can be used:

- Inlet temperatures can be reduced by cooling the produced fluid in a heat exchanger. Seawater is available in large quantities as a cheap, cooling medium for offshore operations
- Pressures can be reduced by a choke or other type of pressure reduction value
- Corrosivity can be reduced by injection of corrosion inhibitors.

4.2 Separators

Separators are key in the production process. There are two major types by the separation mechanism:

- Gravity separators which depend on the density difference between the phases to be separated.
- Centrifugal separators in which the separation is enhanced by high velocity rotation of the fluids.

By construction, there are horizontal, vertical, and (less commonly used) spherical gravity separators.

Horizontal gravity separators are essentially large cylindrical pressure vessels up to 5m in diameter and up to 20m long. They are used for either 2-phase (liquid/gas) separation, or 3-phase (water/oil/gas separation). When the mixture enters this large cylinder its velocity decreases, and most of the gas bubbles should have enough time to float up to the top of the separator, while liquid droplets to settle down in the bottom, in these slower and calmer flow conditions. The time the fluid takes to cross the separator is called 'retention' or 'residence' time. The gas is continuously vented off the top, while the liquid is let off the near-bottom outlet of the separator. However, some smaller bubbles and droplets may still remain dispersed in the opposite phase.

A single separator therefore is seldom 100% efficient, so they are normally mounted in a series of 2, 3 (Figure 14) or even 4 separators with inlet and outlet under pressure control, with progressively decreasing pressure in every next stage.

Two horizontal separators can also be mounted and connected vertically as a 'double-barrel' or 'double-tube' separator with improved efficiency. Horizontal separators are often the first choice, however in the cases where the platform space is limited or there is severe flow surging (e.g. due to slugging) then more expensive, vertical separators are considered.

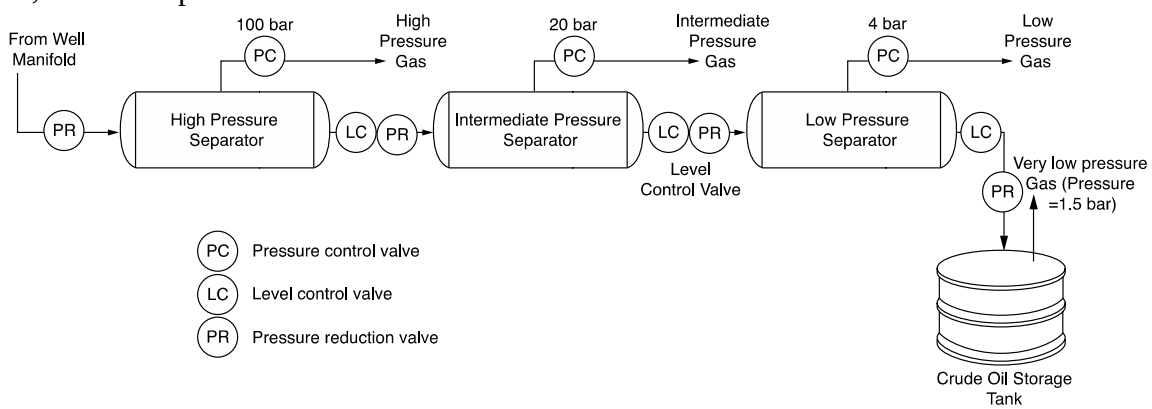


Figure 14 Simplified 4-stage, two phase (gas / liquid) separation. *(The storage tank is counted as a stage).*

Gravity separators (Figure 15) consist of an:

(i) **Inlet or diffuser section** with momentum breaker/inlet deflector to rapidly reduce the inlet liquid velocity; hence helping disengage free gas. *In vertical separators there is an inlet diverter baffle installed that makes the fluid spin resulting in the liquid droplets accumulating due to centrifugal forces. These coalesced, larger droplets will then settle faster.*

(ii) **Gravity settling section**, typically sized so that:

- (in 2-phase separators): there is sufficient gas phase residence time such that liquid droplets with the size as small as 100 µm (µm = micrometer a.k.a. micron) will separate from the gas.

Also, gas scrubbing baffles can be installed in the upper part of the separator to make sure the liquid droplets, dispersed in gas, collect in the grooves and then flow as a film trickling to the lower (liquid residence) section.

- (in 3-phase separators): same as for 2-phase separators plus sufficient oil phase residence time such that 500 μm and larger water droplets will settle from oil into the water phase. The separated water phase will typically contain 500-2000 ppm dispersed oil, with this oil-in-water (a.k.a. 'reverse') emulsion requiring further treatment before disposal. The emulsion can be 'tight' (difficult to break) or 'loose'.

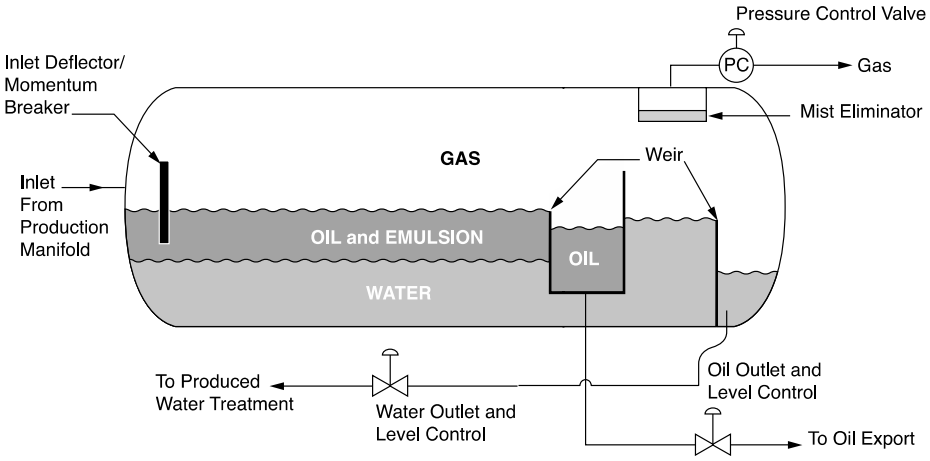


Figure 15 Three phase, horizontal separator.

The above criteria are based on the settling theory. Alternatively, experiments may be carried out to measure the accurate rate of oil/water separation for a given case. The initially produced intimate oil and water mixture (emulsion) separates into a lower, "clean" or 'free' (i.e. low oil content) water layer and an upper, "dry" (i.e. low water content) oil layer with a (more persistent) emulsion layer in-between (Figure 16).

In multi-stage separators ('separator trains') the dry gas and oil and free water are drained from the separator, so the remaining mixture is directed into the next stage separator, where it has a longer retention time due to lower rate, and thus another, better chance to separate.

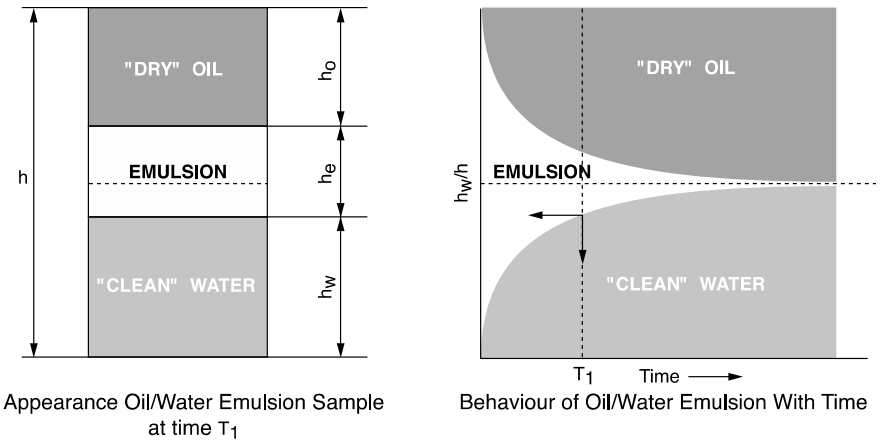


Figure 16 Separation of oil and water from an emulsion.

(iii) **Gas outlet.** A mist extractor or eliminator is installed at the gas outlet to retain the remaining liquid droplets. One mist extractor design is a wire pad of thin stainless-steel wire wrapped in a cylinder. It is designed to remove liquid droplets between 10 μm and 100 μm from the gas phase. These droplets

impinge on the wire, coalesce and flow down into the liquid phase. Efficient operation depends on operating the separator with the correct gas velocity:

- Too high gas velocity – liquid drops are "eroded" from wire and are re-entrained in the gas stream
- Too low gas velocity – liquid drops flood the extractor and drift past mesh without impinging
- A gas scrubber (mentioned above) is employed if larger droplets (up to 500 µm) have to be removed first, otherwise the mist eliminator would be flooded with this level of liquid loading.

Gas outlet is controlled by a backpressure (pilot) valve that adjusts to keep the gas (and separator) pressure value constant.

(iv) **Liquid outlet** under liquid level control (LLC) valve is used to evacuate the liquid or the separated oil and water phases (2 or 3-phase separators respectively). The outlet is usually equipped with a vortex breaker to prevent re-entrainment of gas in the liquid. Weir (a dam-like element to skim oil off water) is installed in a 3-phase separator (Figure 15).

The separators work efficiently at a certain design gas pressure and the liquid level. Vertical separators have larger 'surge room' i.e. can tolerate surging and the consequent liquid level change better.

Separators can also be equipped with gauges and (safety relief, rupture disc, etc.) valves that operate to avoid high/low pressure or temperature conditions.

4.2.1 HORIZONTAL SEPARATORS

Horizontal separators (Figure 15) are most suited to separation of large volumes of gas from liquid (i.e. for high GLR oils). Compared to vertical separators they:

- Have a larger gas/liquid/liquid interface area, giving better foam/emulsion handling characterisation
- Have a larger "footprint"
- Require a more complex jet wash system if solids have to be removed from a larger surface area
- Have a lower surge capacity i.e. reduced ability to deal with uneven, inlet flow

4.2.2 VERTICAL SEPARATORS

Vertical separators (Figure 17) are preferred for the separation of gas from large volumes of liquid (i.e. low to medium GLR oils). Compared to horizontal separators they are:

- Good for uneven, surging inlet flow due to their greater height
- The oil/gas and oil/water interface level control is less critical for the same reason
- Tend to be larger than their horizontal equivalent for the same separation capacity
- Have a smaller "footprint"

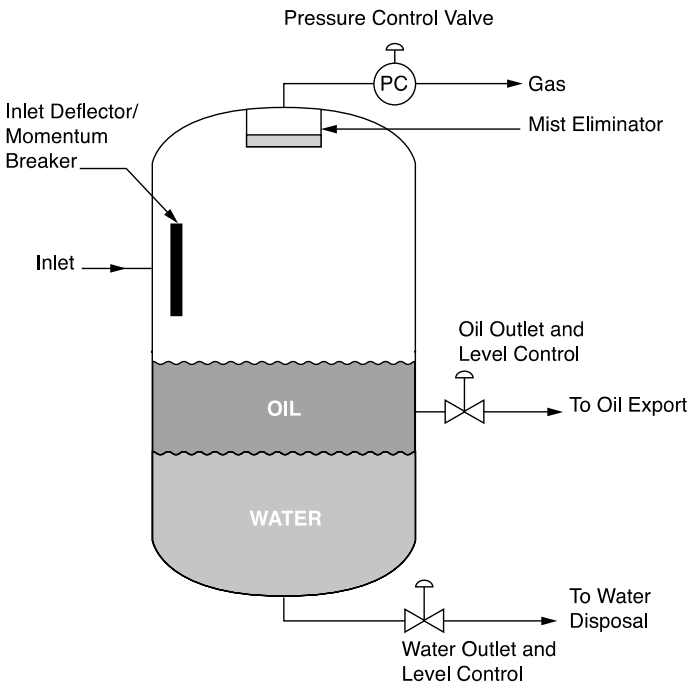


Figure 17 Vertical, three phase separator.

Separators are used for primary separations of fluid phases, but can also be added in various other elements of the processing scheme. In these other various roles they are referred to as 'scrubbers', 'knockouts', 'free liquid knockouts', 'free water knockouts' FWKO vessels, etc.

Fluid separation depends on the

- separator pressure (the higher the better since the gas is more compressed and thus the mixture flow velocity is smaller and the retention [i.e. fluid transit or residence] time is higher),
- separator temperature,
- fluid composition.

As mentioned, the efficiency of the free phases' separation depends on the droplet settling velocities. Another effect present is the phase exchange: gas evolves from oil by flash vaporisation at the separator pressure and temperature conditions, e.g. in a multi-stage separator this will take place from separator to separator at a gradually decreasing pressure and temperature. The flash vaporization efficiency can be estimated using the vapour-to-liquid ratios (equilibrium constants). Theoretically the more stages are used the higher liquid content can be recovered, though practically extra stages on top of two-stage separation yield extra 2-12% liquid volume which seldom justifies these extra stages. Computer simulation of phase behavior of the fluids is used to select the appropriate separation conditions to maximize the field development NPV.

The separator pressure is normally within the range of 20 to 1500 psi. The first, high-pressure separator in the train is often selected equal to the gas export pipeline (if any) pressure (typically 700-1000 psi).

The fluid retention times required in the separator typically vary from 1-2 minutes in high-pressure separators to 5-10 minutes in the subsequent, low-pressure ones, though can be required/designed to be longer e.g. in heavy oil and/or at low temperature production conditions.

4.3 Horizontal Separator Sizing Basics

The liquid droplets will settle at a velocity determined by equating the gravitational force acting on the drop with the drag force caused by its relative motion in the continuous phase. Typical trajectories of the settling liquid droplets are shown in Figure 18. This assumes that the internals of the separator have been designed so that turbulence effects are minimised e.g. there are inlet deflectors/momentum breakers, vortex breakers on the outlet, etc.

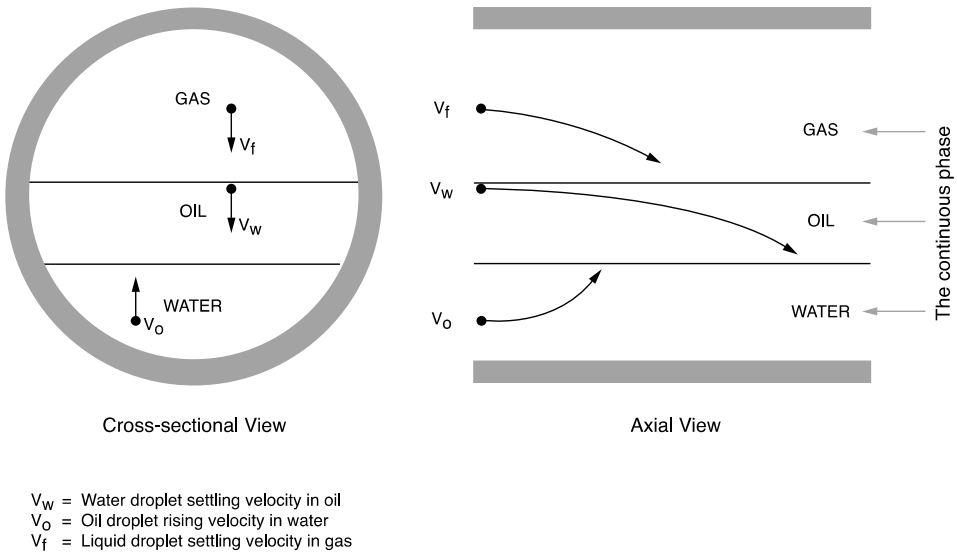


Figure 18 Settling droplet trajectories.

4.3.1 GAS CAPACITY

Separators are typically designed to allow liquid droplets larger than 100 µm to settle from the gas phase to the liquid interface. The maximum allowable gas velocity (V_g) which achieves this separation may be calculated using the Souder-Brown equation:

$$V_g = k\sqrt{\frac{\rho_l - \rho_g}{\rho_g}}$$

where ρ_l = liquid density

ρ_g = gas density

k = constant

The constant k is related to the diameter of the droplet to be separated (e.g. 100 µm), the gas viscosity and the densities of the liquid and gas phases. Calculation of the constant k is complicated since the settling flow regime may not be laminar.

The minimum area required for gas flow (A_g) is then:

$$A_g = Q_g / V_g$$

where Q_g is the specified maximum gas flow rate.

The separation efficiency can be improved by modifying the separator facilities, e.g. the constant k is higher in horizontal separators, or when a mist eliminator is installed.

4.3.2 LIQUID CAPACITY

The separation velocity (v) of one liquid from another is described by Stokes Law:

$$v = \frac{Kd^2 (\rho_d - \rho_c)}{\mu_c}$$

where

d	=	minimum specified droplet size to be separated
ρ_d	=	density of discontinuous phase
ρ_c	=	density of continuous phase
μ_c	=	viscosity of continuous phase
K	=	a constant depending on units and the settling regime

$$\text{Required droplet separation time} = \frac{\text{vertical height of continuous phase}}{\text{separation velocity}}$$

The separation of water droplets from oil is normally more difficult than oil from water because oil is normally more viscous than water. If no other information is available, general field experience indicates that one needs to achieve removing water droplets ≤ 500 µm from the oil in the primary separator, and similarly oil droplets ≤ 500 µm from the water which would typically reduce oil-in-water content to 2,000 ppm or less. Similar arguments apply to the calculation of the constant K as was discussed for gas capacity. These calculations, along with the specified liquid flow rates, allow the area required for liquid flow to be specified.

An alternative approach is to base the separation requirements on emulsion separation tests which specify a required separation time (Figure 16). Separators are typically run 50-75% liquid full. Hence, knowledge of the design liquid flow rates and the required residence times allow the separators length and diameter to be calculated. An increased separator diameter is required to compensate for surging flow as well as allows sufficient volume to give an adequate response time between high and low level alarms before a high or low level trip leads to a shut down. An additional 30 - 60 seconds hold-up volume is typically specified. Table 11 summaries the resulting performance of a typical three stage separation process.

4.4 Operational Production Problems with Gravity Separators

The process equipment used in platform operations is designed to achieve the required product specifications using standard chemical engineering design procedures. However, operational problems can be encountered if allowance is not made for the fact that we are not processing "pure" fluids and that the fluid flow rates composition and qualities will vary over the life of the field. The complex mixture that makes up the produced hydrocarbon contains many minor components that cause:

4.4.1 FOAMING:

Foam (semi-stable gas bubbles at the oil/gas surface) prevents the gas disengaging quickly from the liquid surface. A de-foaming chemical (a surfactant) is injected at a low concentration to overcome this problem. An effective defoamer coupled with a mist eliminator will remove liquid droplets larger than 100 μm from the gas stream.

4.4.2 SOLIDS

Low concentrations of solids are frequently produced to surface with the well fluids. They represent a large absolute solid volume even if present in low concentration due to the large volumes of produced fluid. These solids range from "fines" (micron sized clay particles which can flow through the formation pore throat structure) to individual sand grains or even larger "lumps" of formation. These solids collect in the bottom of the separators where they reduce fluid residence time and the separation efficiency. This can also cause corrosion in the stagnant fluid. They have to be regularly removed. Water jets are mounted at the bottom of the tank. Their jetting action re-suspends the solids and transports them to a holding tank for removal of any oil and for ultimate disposal. Alternatively, manual removal of the solid deposit is required.

Several other solid phases can appear in the separators and the other components of the production system. These include:

- **Scales** These are formed by the mixing of incompatible waters {e.g. barium sulphate from mixing sea water (sulphate source) and produced water (source of barium)}; and/or by pressure/temperature changes (e.g. resulting in the calcium carbonate scale). Scale deposition can be controlled by the addition of a scale inhibitor

- **Wax** Cooling of the crude oil in the production system may result in part of the paraffin content precipitating as a solid wax. This is avoided by preventing the crude cooling below the wax appearance temperature or cloud point. The temperature at which wax deposition occurs can be controlled to some extent by the use of wax inhibitors.

- **Asphaltenes** Pressure reduction can lead to the precipitation of asphaltenes from some crude oils

4.4.3 EMULSION

Momentum breakers and corrugated plate settling packs are installed within the separator to promote oil droplet coalescence and separation. However, emulsion separation may not be sufficiently complete within the residence time available in the primary separator. This depends on the chemical properties of the crude oil/water system and the extent of shear that the fluids have been subjected to during the production process. Heating the more viscous crude oils (e.g. in heat exchangers, by insulating pipelines, or by installing a gas-fire heated pipe inside a 'heater treater' type separator, etc.) will speed the separation of water droplets from the oil as well the addition of emulsion breaking chemicals; together with acceptance of reduced oil and water quality being passed to the subsequent separation stages.
Also, electrostatic separation may be used to reduce water content of relatively dry oil. The water droplets suspended in the oil carry a small electrical charge. Their rate of settling can be increased by imposing the appropriate electrical field across (a part) of the settling region inside the separator. Since this can only work in a relatively dry oil, such separation is not always applicable.

4.4.4 SURGING FLOW

The primary separator provides pressure control on all three (gas/oil/water) outlets. It controls residence time via the oil/water level controls. Production wells may not produce fluid at a constant even flow rate. This is due to the length and topology of the production tubing and flow lines. These problems are accentuated by incorrectly set gas lift (resulting in well heading) as well as the long flow lines associated with subsea wells. The separation system must be capable of dealing with the resulting high, instantaneous changes in feed rates which can cause the levels to increase above their normal, operating values. The control system needs to be suitably adjusted to deal with this.

4.4.5 PRODUCTION CHEMICALS

In addition to those already discussed, other production chemicals used include corrosion inhibitors. Figure 19 is a typical example of where they might be used in an oil/gas/water separation system.

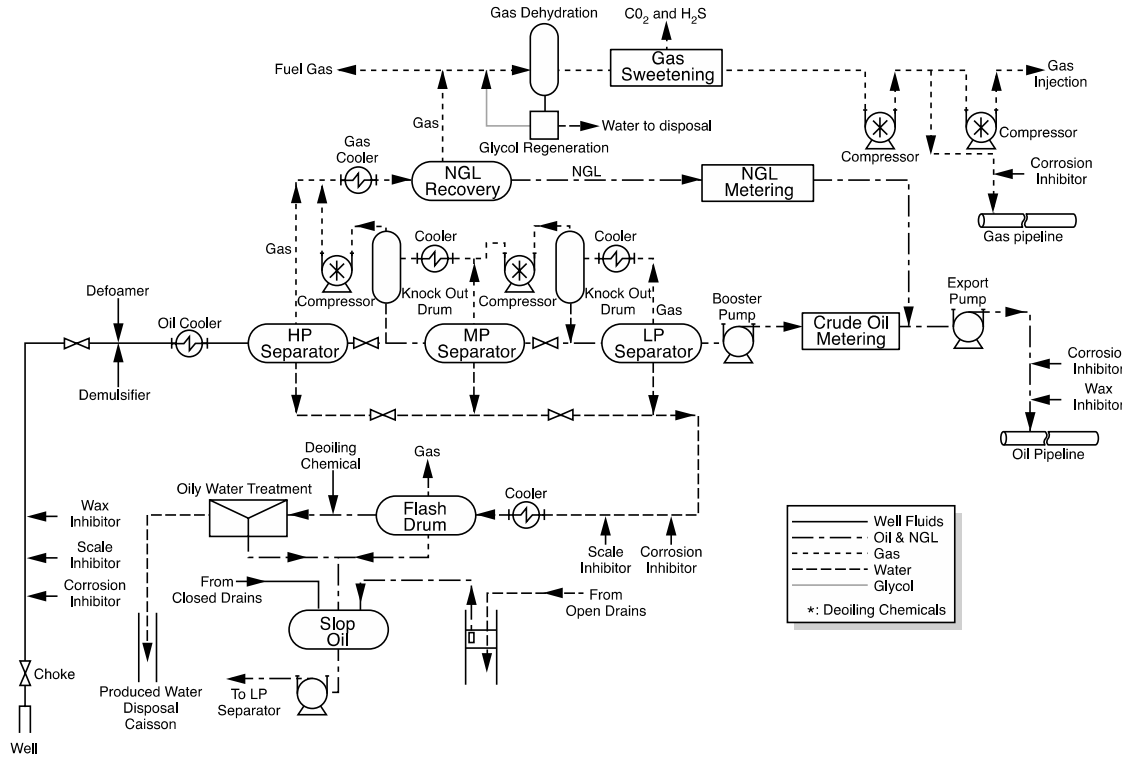


Figure 19 Typical Oil/Gas/Water process flow scheme (PFS).

4.4.6 MISCELLANEOUS PROCESSES AND COMMENTS

A **fresh** water wash may be required to reduce the salt content of the crude oil to the sales specification value if the formation water has a high salt content. This involves mixing the crude with the water followed by subsequent separation.

The main separation train may be twinned (i.e. two separation trains of equal capacity) to increase the reliability (uptime) of the separation facility. A smaller, 3-phase, test separator will also be installed to allow rates from individual wells to be measured periodically as part of the field monitoring programme. The test separator may be omitted if a reliable, multi-phase, continuous flow meter is available.

Separator Stage	Water Residence Time (min)	Oil Residence Time (min)	Target Water in Oil (%vol)	Target Oil in Water (ppm)
1st	4	2	2	2000
2nd	>6	4	1	400
3rd	>8	6	0.25 meets sales specification	100 further processing required before disposal

Table 11 Performance targets for a typical 3-stage separation system.

The oil separation efficiency has to meet the export requirements. Oil samples are regularly collected and analysed to adjust the separation system. For instance, oil samples are checked that the amount of 'base sediment and water' (BS&W or BSW) fraction in a sample is less than the export limit, typically 1%.

- *Feel free to attempt Tutorials 1 and 2*

4.5 Test Separator

The production from each well has to be regularly measured accurately as part of the field's well surveillance programme. Accurate three phase flow meters have become available relatively recently. Traditionally a small, three-phase separator (the test separator) has been used for this purpose. Here, the well production is split into its constituent phases (oil/water/gas) and the flow rate of each phase measured separately with conventional orifice meters. The oil and water flows are recombined for further processing.

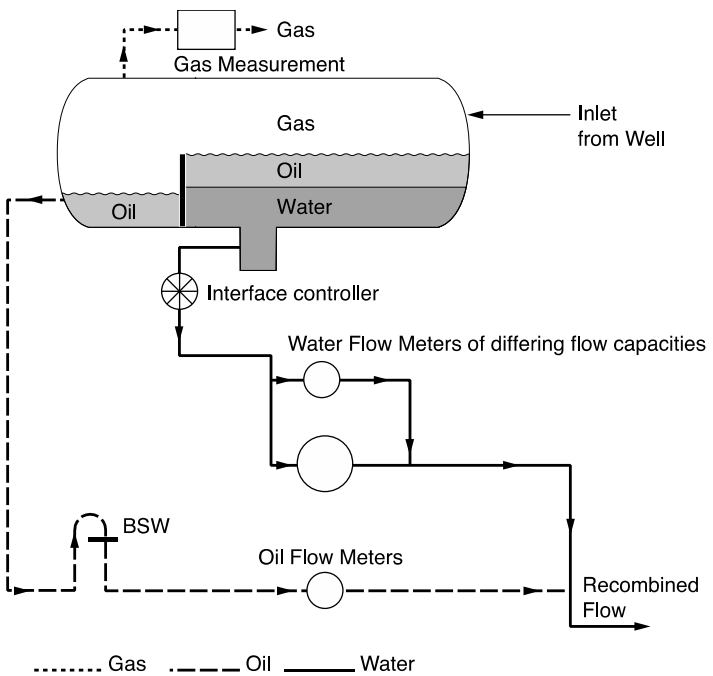


Figure 20: A test separator.

Multi-phase flow meters are now becoming reliable. This is reducing the need to install a test separator (for the sake of platform space and weight saving) as well as the need to install a second (test) pipeline in subsea field developments between the manifold and the host facility.

5. COMPRESSORS

The gas liberated from the produced fluids must be delivered to the export pipeline at the specified pressure. It is flashed from the produced liquid at a variety of pressures during the production process. A number of gas compressors rather than a single large one is used to recompress the gas to the export pipeline pressure. Minimising the compression power requirements while maximising the liquid recovery (determined by the thermodynamics of the produced fluids), will dictate that the gas from each oil separation stage is compressed to the operating pressure of the previous stage (Figure 21).

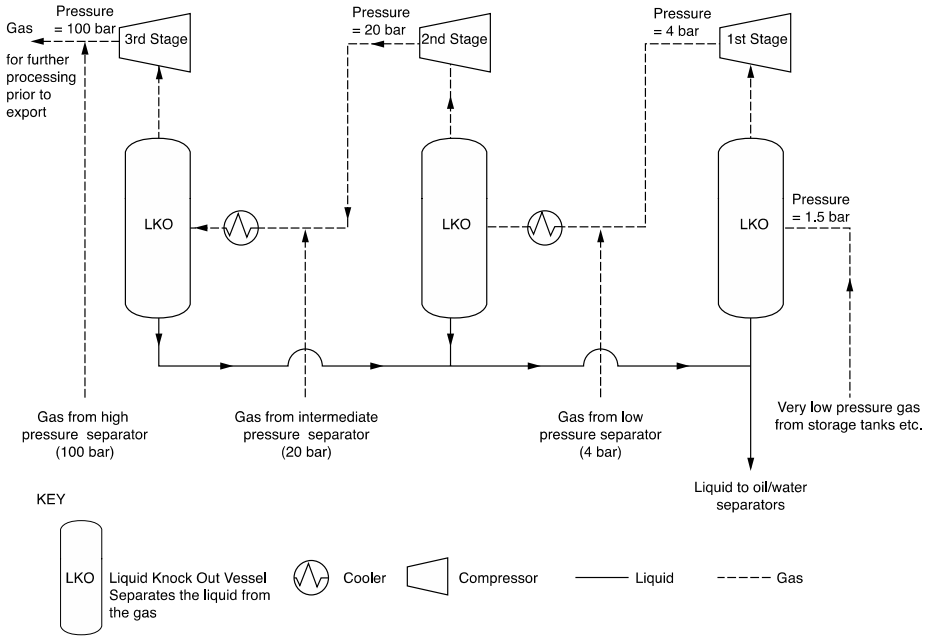


Figure 21 Schematic 3-stage compression scheme.

The action of the compressor performing work on the gas being compressed raises its temperature considerably (the "bicycle pump effect"). The use of interstage coolers, as shown in Figure 21, results in minimisation of the compressor power requirements (because the cooler gas is by nature more compressed) together with maximising of the liquid recovery (because liquids condense on cooling the gas). Off-shore, sea water is used for such cooling. Table 12 summarises the combined result of the above effects.

System Design	Separator Pressure (bar)	Oil Production (m^3)	Compression Power *(kw)
Two stage separation	80, 5	1300	640
Three stage separation	80, 30, 5	1315	370
Four stage separation	80, 30, 12, 5	1321	295

*Omission of compressor interstage coolers increases this by 50%

Table 12 Effect of multiple separator/compressor stages.

The prime mover or engine chosen to power the compressor depends on the compressor's location and the power required. Gas turbines, diesel engines and electric motors are all frequently employed.

Both centrifugal and positive displacement reciprocating compressors are both commonly used in oil field applications. Both compressor types are susceptible to damage by liquid droplets, hence the presence of the liquid knockout vessels (essentially these are gas-liquid separators) prior to each compressor.

6. OIL EXPORT

The volume of oil being exported has to be measured to the highest accuracy. This measurement not only defines the project's product and cashflow but also involves both fiscal (tax/royalty etc.) and intercompany transfer (e.g. to a "common carrier" pipeline).

Turbine flow meters – which work by measuring the number of times that the flowing oil revolves a paddle or turbine placed in the oil flow path – have a high, intrinsic accuracy. However, they have to be calibrated (or "proved") at regular intervals. 5 to 10 smaller capacity turbine flow meters are used in parallel rather than a single, large meter.

The calibration process is illustrated in Figure 22. The flow rate as measured by the turbine flow meter is compared with that calculated in the 'prover' flowmeter from the time taken by a sphere to be displaced between two detectors and the volume between these detectors.

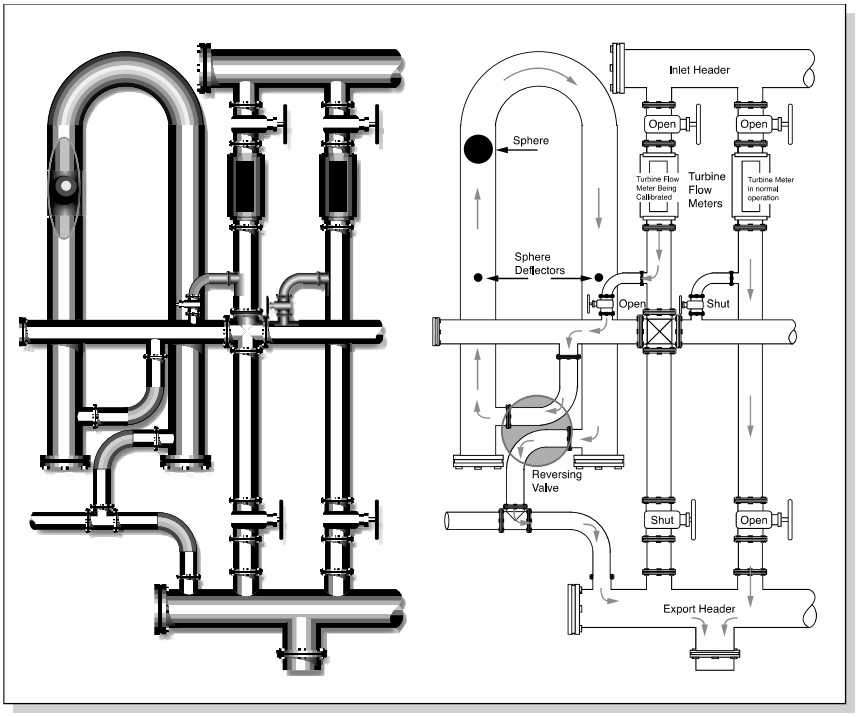
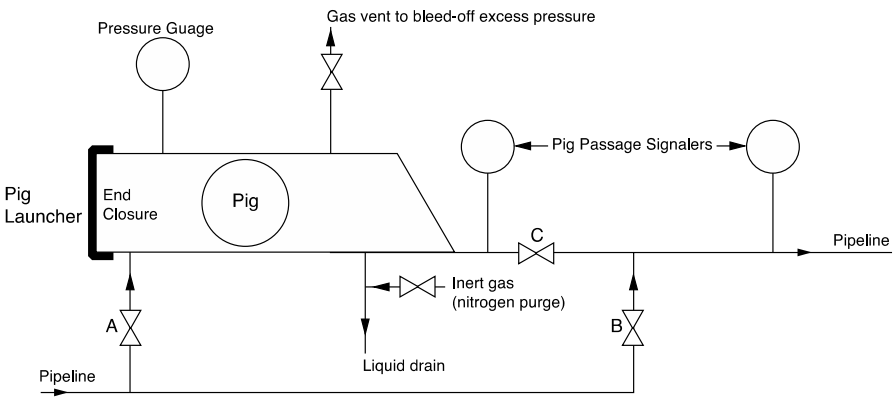


Figure 22 Meter calibration system for oil export pipeline.

Oil export depends on efficient pipeline operation. The pipeline requires regular cleaning by a "pig". This removes settled sand or stagnant water which collects at low points in the pipeline. The pig also maintains the pipeline's full diameter to flow by removing wax and other deposits. The "pig" may be in the form of a sphere to displace fluids or a cylinder with brushes or caps to scrape the inside surface of the line. Alternatively, it may have "intelligence" in that it can inspect the pipeline condition and record the results for later replay. The "intelligent" pig uses similar techniques as employed for well (tubing) condition monitoring {e.g. mechanical arms to "feel" for corrosion pits and grooves or acoustic wall thickness measurement devices etc.} As an aid to recovery, the pigs often contain a transmitter so that their position can be pinpointed if they become stuck in the pipeline.

The pig is "launched" into the pipeline using a pig launcher (Figure 23). This is an oversized barrel with end closure, pressure gauge, venting and purging system to allow any hydrocarbons present in the "launcher" to be depressurised and disposed of in a safe manner. Opening of any pressurised lines which could potentially contain hydrocarbons is a hazardous operation which requires proper attention to safety and environmental aspects.

A pig "signaller" is built into the launcher. This confirms the successful launch of the pig into the pipeline. A duplicate of this equipment is installed at the receiving end of the pipeline to record the arrival of the pig and to allow its safe removal from the pipeline. This is called the Pig Receiver.



Status	Valve A	Valve B	Valve C
Normal Pipeline Operation	Closed	Open	Closed
Displace Pig in Launcher	Open	Closed	Open

Figure 23 The Pig Launch System.

7. GAS HANDLING

Similar process units are used in oil field gas handling as are used in gas fields. In both cases one of the objectives is to maximise the recovery of Natural Gas Liquids (NGL). This liquid product consists mainly of hydrocarbons with four or five carbon atoms. This is achieved in oil fields by multi-stage separation and (gas) compression – as discussed above. Figure 24 illustrates typical gas field facilities. It shows single stage separation with optional gas compression and processing as dictated by the producing wellhead pressure and gas composition respectively, and is the norm for gas fields.

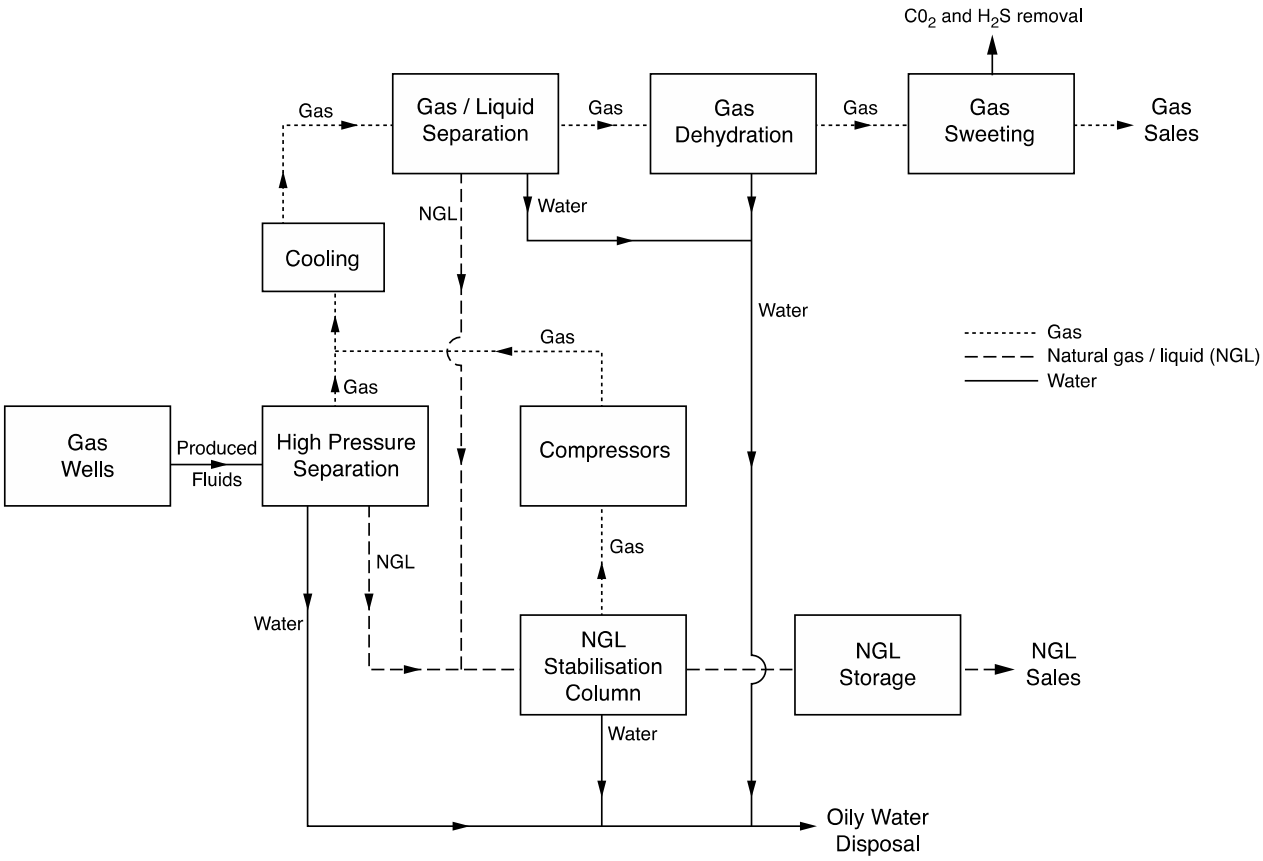


Figure 24 A Gas Field Process Scheme.

7.1 Increasing NGL Recovery

The increased NGL yield together with a reduction in the water content, is achieved by cooling the gas. This can be achieved by refrigeration, by gas throttling (and thus cooling) effect, by making gas do work in power turbines (this also results in cooling), or by adding chilled liquid (e.g. glycol) that absorbs NGLs.

7.2 NGL Stabilisation

The separated NGL has a high vapour pressure due to a high concentration of dissolved, volatile, low molecular weight hydrocarbons (methane, ethane etc.). It is not yet suitable for storage in a tank or onward transport to customers. The vapour pressure has to be reduced by heating the NGL to progressively higher temperature in a series of separators and allowing the gas to "flash-off" at their constant pressures.

The same process can be carried out more efficiently in a distillation column. The column consists of a number of trays containing bubble caps which forces the gas rising upwards into intimate contact with the liquid on the tray. The liquid undergoes a series of multiple flashes at downward increasing temperature and constant pressure as it trickles down the column. Any water that is present will tend to concentrate at the tray operating at just below its boiling point under the column operating pressure. A separator may be installed on this tray and the water removed for disposal.

7.3 Gas Dehydration

Produced Natural gas is saturated with water vapour under the current downhole and reservoir conditions. Production to the surface and subsequent processing normally involves a progressive reduction in the gas temperature (and pressure). The equilibrium water content of the gas phase decreases as the temperature drops or the pressure increases, resulting in the separation of the liquid water.
Liquid water accumulates at pipeline low points, reducing the production and accelerating pipeline corrosion and slugging. The water content in gas also reduces the gas heating value and therefore its market value. It also forms solid hydrates (ice-like looking solids) which can plug lines, valves etc. *(One solution to preventing operational problems from hydrate formation is to add an (expensive) inhibitor e.g. methanol or glycol to the gas stream).*

The saturated water content of natural gas varies at temperature and pressure and is typically around 100 lb / MMscf. The gas pipeline acceptable water vapour content however is typically about 6-8 lb / MMscf or less.
The water content is often associated with the gas **Dew Point** i.e. the temperature at a given pressure, at which gas becomes saturated with water vapour and thus water starts condensing from the gas. The lower the dew point is, the lower is the vapour content. Reduction of the dew point temperature e.g. by 80° F is called '80° F dew point depression'.

Gas dehydration can be generally achieved by gas cooling (of compressed or uncompressed gas) as mentioned above in relation to NGLs, and also by absorption (of water by liquids) or adsorption (of water by solid desiccant).

7.4 Continuous Dehydration Process

In this process there is counter current absorption in a (packed) column using a liquid desiccant such as (triethylene) glycol: the wet gas enters the contactor column at the bottom while the "lean" (low water content) glycol is pumped in at the top. The glycol trickling down the column is brought into intimate contact with the gas bubbling upwards. The water vapour is absorbed by the glycol.
The waters-saturated, "rich" glycol/water mixture is drawn off from the bottom of the contactor tower and 'regenerated' by boiling in a distillation column, and then re-used again.
Triethylene glycol can typically achieve a dew point depression of 55°C to 85°C. Further reductions in the dewpoint e.g. to -100°C for gas destined for a cryogenic liquefied natural gas (LNG) plant, require use of a solid desiccant.

7.5 Batch Dehydration Process

As mentioned, very low dew points can only be achieved with solid bed dehydration systems. It consists of:

- Two or more desiccant filled contactor vessels (Figure 25)
- A heater to supply hot, regeneration gas
- A cooler, to condense water from the used regeneration gas, together with a separator

The solid desiccant (e.g. silica gel, alumina gel, molecular sieve etc.) has a very large specific surface area. This allows it to adsorb water from the (wet) gas passing downwards through the contactor at near ambient temperatures (30° - 40°C). Once the entire bed has become saturated with water, the inlet (wet) gas is switched to a second tower containing fresh absorbent. The saturated (spent) tower is then regenerated by passing heated gas through it. Once regenerated, the desiccant bed is cooled by passing cool inlet gas – to its operating temperature (30 - 40°C) before it will work efficiently. The "fresh" tower is then available for operation when the tower currently in use becomes saturated with water vapour. The towers are typically sized so that they work on an 8-hour adsorption cycle followed by regeneration through six hours heating and two hours cooling.

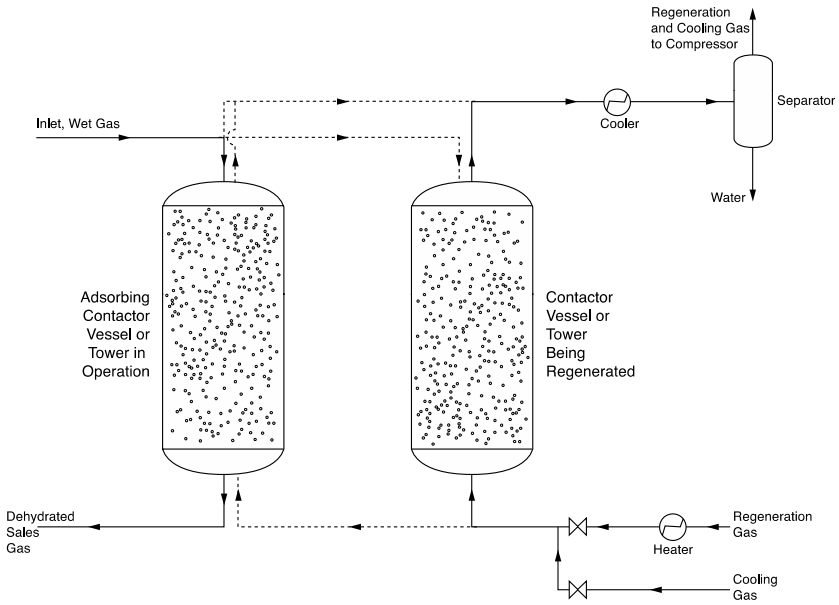


Figure 25 Schematic flow diagram for solid bed dehydration.

7.6 Acid Gas Treating (Gas Sweetening)

Natural gas frequently contains contaminants such as carbon dioxide (CO_2), hydrogen sulphide (H_2S) and other compounds. They reduce the gas heating (and thus market) value, and can cause pipeline corrosion.

The maximum allowable CO_2 and H_2S concentrations are normally specified in the gas sales contract – typical values are 3% and 4 ppm respectively. Low concentrations of H_2S may be removed by solid absorbents (e.g. iron oxide or zinc oxide) which are replaced once they have reacted with the H_2S. Higher concentrations of H_2S as well as CO_2 are removed by a solvent extraction process similar to the glycol dehydration unit discussed above. One class of solvents used for treating acid gasses are alkaline liquids that react with the acidic gases. An alternative is a physical solvent e.g. sulfinol that dissolves large quantities of CO_2 and H_2S at low temperature; while releasing them again at high temperatures during regeneration.

There are strict environmental constraints on the quantities of H_2S and CO_2 that can be released into the environment. Alternatives are:

- Injection of CO_2 and/or H_2S into an underground disposal reservoir
- Conversion of the H_2S into solid sulphur which can be sold to the chemical industry.

8. WATER HANDLING

Water production or injection can result in the damage to formation and facilities as well as flow assurance problems due to solids content, corrosion (largely in the presence of CO_2 or oxygen), scale deposition, bacteria, etc. These problems and their mitigation measures (inhibition, bactericides, etc.) have been extensively discussed earlier in this course.

9. PRODUCED WATER TREATMENT

As mentioned (Table 1), large changes in the volumes of produced water are typically experienced during the life of a production project. Well management solutions can be used to reduce the produced water content, e.g. by isolating watered out intervals, controlling flowrate/drawdown to delay formation water coning or injection water breakthrough, etc.

- *Feel free to discuss the water production control measures.*

Nonetheless, the facilities have to be designed to treat water and operate efficiently over these wide range of conditions. *(On top of the production water, some other, minor water volumes e.g. used in equipment or tanker cleaning may also need treatment).*

9.1 Introduction

Gravity separators – the normal method for separating water from the co-produced oil and gas phases – were discussed earlier. As mentioned, this primary separation of oil from water may be enhanced by:

- **Heating of the crude** oil to enhance water separation via viscosity reduction
- **Addition of de-emulsification chemicals** which alter the interfacial tension between the oil and the water, allowing the emulsion to break and the droplets to settle.

Even with the above enhancements, the first stage gravity separator leaves typically 500 - 2,000 ppm oil in the water. A further treatment/processing step(s) are required before the water is fit for disposal. The following process schemes have been developed to reduce the oil content of this oily water.

9.2 (Corrugated) Plate Interceptors

Corrugated plate interceptors work by reducing the distance required for a droplet to migrate before it comes into contact with other oil droplets and coalesces. The interceptor pack consists of a series of closely spaced, parallel plates mounted at an angle of 45° (Figure 26). These plates have a corrugated profile {similar to the well-known roofing material (Figure 27)}. This profile allows the oil to collect at the high point, where the individual droplets coalesce and the resulting larger droplet has higher buoyancy and moves upwards, under the influence of gravity and against the direction of water flow.

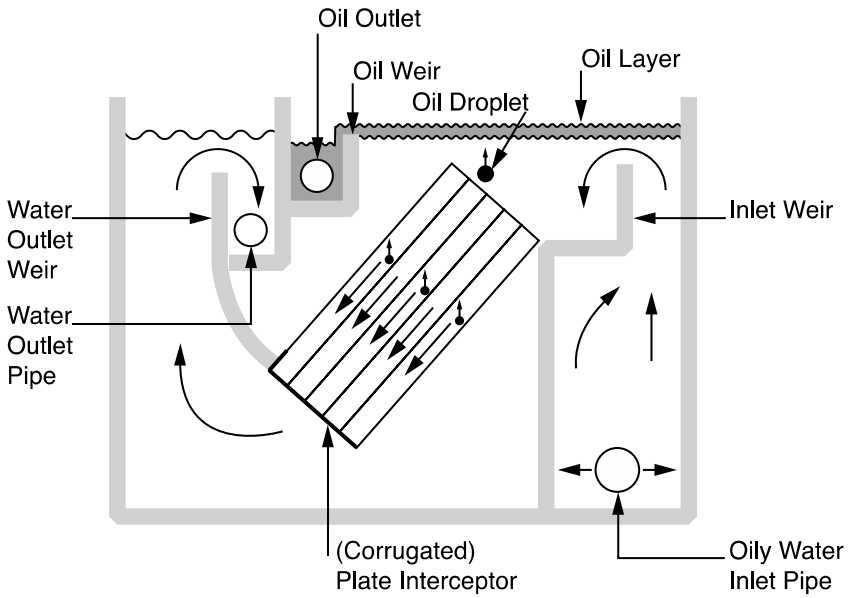


Figure 26 (Corrugated) Plate Interceptor.

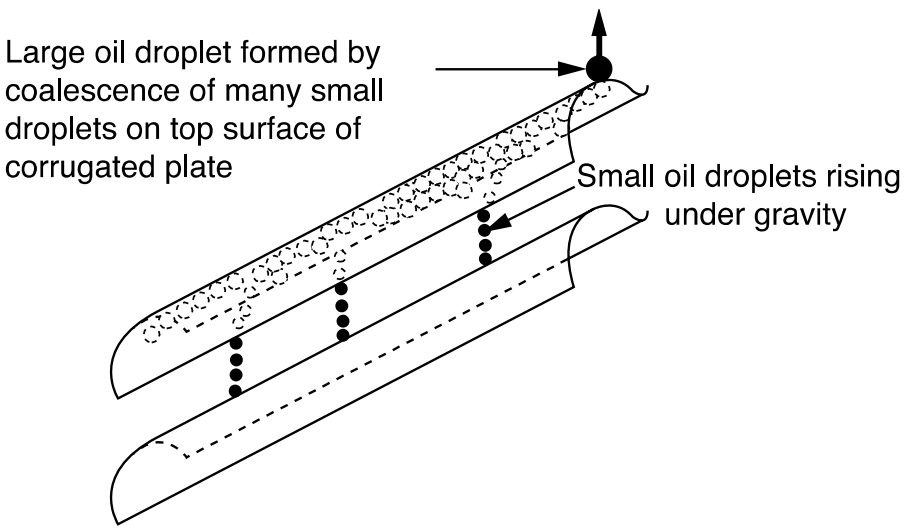


Figure 27 Oil droplets coalescing in a corrugated plate.

The configuration of the water inlet and outlet pipes is so arranged that any turbulence that might lead to re-mixing of the small oil droplets is minimised. Removal of oil droplets as small as 60 μm is frequently achieved. These plate separation packs may also be installed inside gravity separators in order to enhance their performance.

9.3 Flocculation/Coagulation

The separation of suspended liquids (oil) and solid material can be enhanced by artificially increasing their size and their ability to coalesce. This is done by chemical flocculation. This process uses a chemical (such as Ferrous Sulphate) which forms a voluminous precipitate in contact with water. This precipitate has the ability to coagulate into large flocs and, in the process, destabilise any suspended particles at the same time. A typical flocculation unit is shown in Figure 28 – it consists of a mixing chamber and a floc growth chamber. This growth chamber gives the microflocs, formed in the mixing chamber, the opportunity to collide, grow and form large flocs. This process can be speeded up by the addition of floc growth catalyst. These are proprietary chemicals available from service companies.

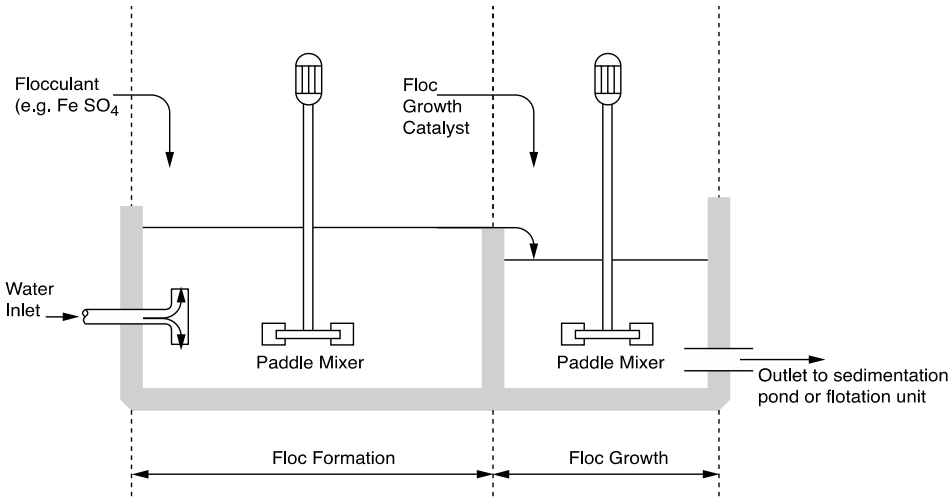


Figure 28 Flocculation unit.

The flocs are subsequently removed from the water stream by settling/sedimentation (due to gravity separation) or by flotation (see the next section).

This type of unit is mainly used for land operations to clean water prior to injection. Treatment of oily produced water by this process means that the oil is not recovered (for sale) and that special measures have to be taken for disposal of the oil containing residue.

9.4 Flotation

Gas flotation uses accelerated separation via the buoyancy (density reduction) effect obtained from rising gas bubbles attaching themselves to the oil droplets. Once the droplets have been carried to the surface they can coalesce, followed by separation of the oil using a weir. The gas can be added to the oily water either by injecting it into the water and dispersing by a rapidly rotating impeller (Figure 29), or by dissolving it in the water under high pressure followed by rapid reduction in the pressure due passage through a throttling valve (the champagne bottle effect) causing bubbling (Figure 30).

In both cases the oil froth is removed at the top and the denser sediment/solids from the bottom.

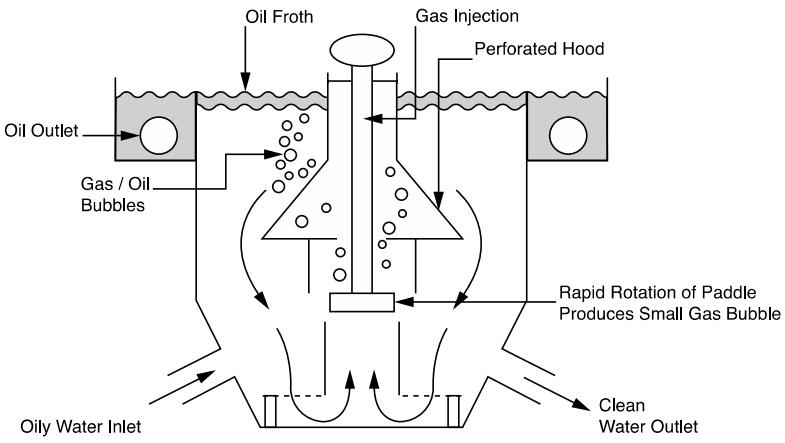


Figure 29 Dispersed gas flotation.

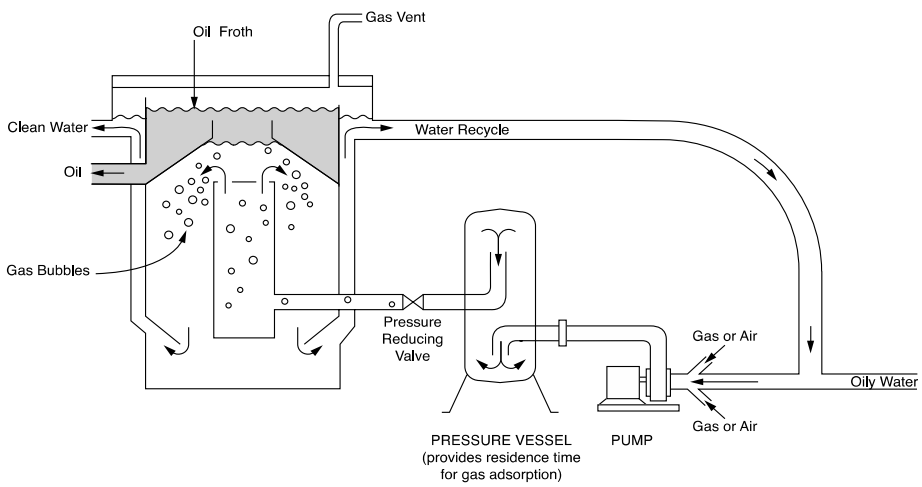


Figure 30 Dissolved gas flotation unit.

9.5 Hydrocyclones

Hydrocyclones work by using centrifugal force to increase the effect of gravity. They have proven to be compact, efficient, and – with the increasing use of Floating Production, Storage and Offtake Vessels to develop marginal oil fields – operate independently of platform motion.

Figure 31 is a schematic diagram of a hydrocyclone. This long, thin device has an upper inlet, where oil-water feed flows tangentially into the upper, swirl section. The oil-water mixture swirls around in a circular path, and is then accelerated as the flow enters the taper section with its reducing diameter. This swirling action causes centrifugal effect that leads to the lighter hydrocarbon phase migrating to the central core. This phase then flows upwards and exits the device via the upper outlet. The (cleaned) water phase passes into the tail section where a back pressure valve controls the pressure drop across the device. The (cleaned) water then exits the hydrocyclone at the lower tail pipe.

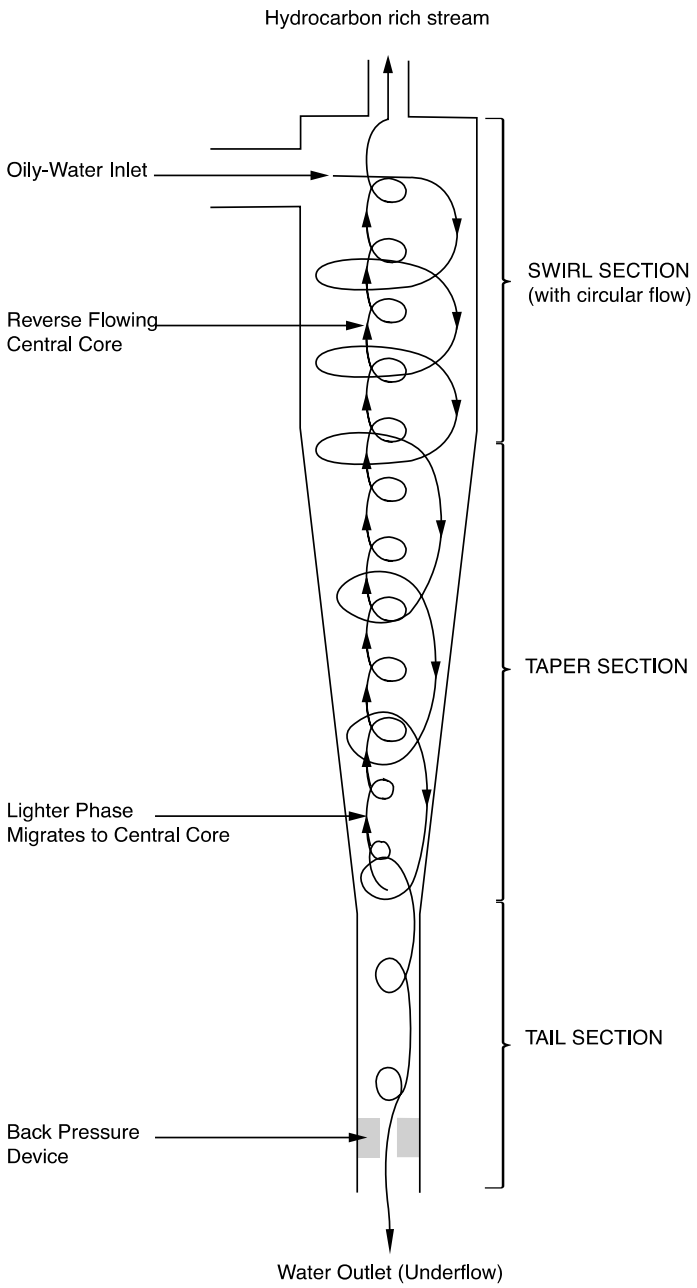


Figure 31 Schematic of a hydrocyclone.

Hydrocyclone performance is sensitive to:

- **Feed rate** – excessively high flow rate reduces performance by causing turbulence
- **Pressure drop** – this is controlled by the back pressure device mounted in the tail section. Proper adjustment of the pressure drop maintains the efficiency of the device's performance. This results in a large turndown ratio (turndown ratio = maximum flow / minimum flow) i.e. the hydrocyclone will separate oil from water efficiently over a wide range of flow rates
- **High oil content** in the oily-water feed, and hydrocyclones are only effective when water is the continuous phase

Each hydrocyclone has a typical capacity of 2,000 bf/d. Hydrocyclones are suitable for modular construction. A number of cyclones are mounted in parallel in a pressure vessel with common inlets and outlets.

A typical modern flow scheme for produced water is shown in Figure 32 – the oily-water phases recovered from the first and second stage separators are treated in separate banks of de-oiling hydrocyclones. The addition of a de-oiling chemical to the hydrocyclone feed is optional and based on the actual producing circumstances. The oil recovered from the hydrocyclones is passed to the low-pressure separator while cleaned water is ready for disposal after a further de-gassing stage.

Hydrocyclons have become the "equipment-of-choice" replacing gas flotation for cleaning produced water. This is due to their compact size, efficient performance and operational robustness in the presence of solids.

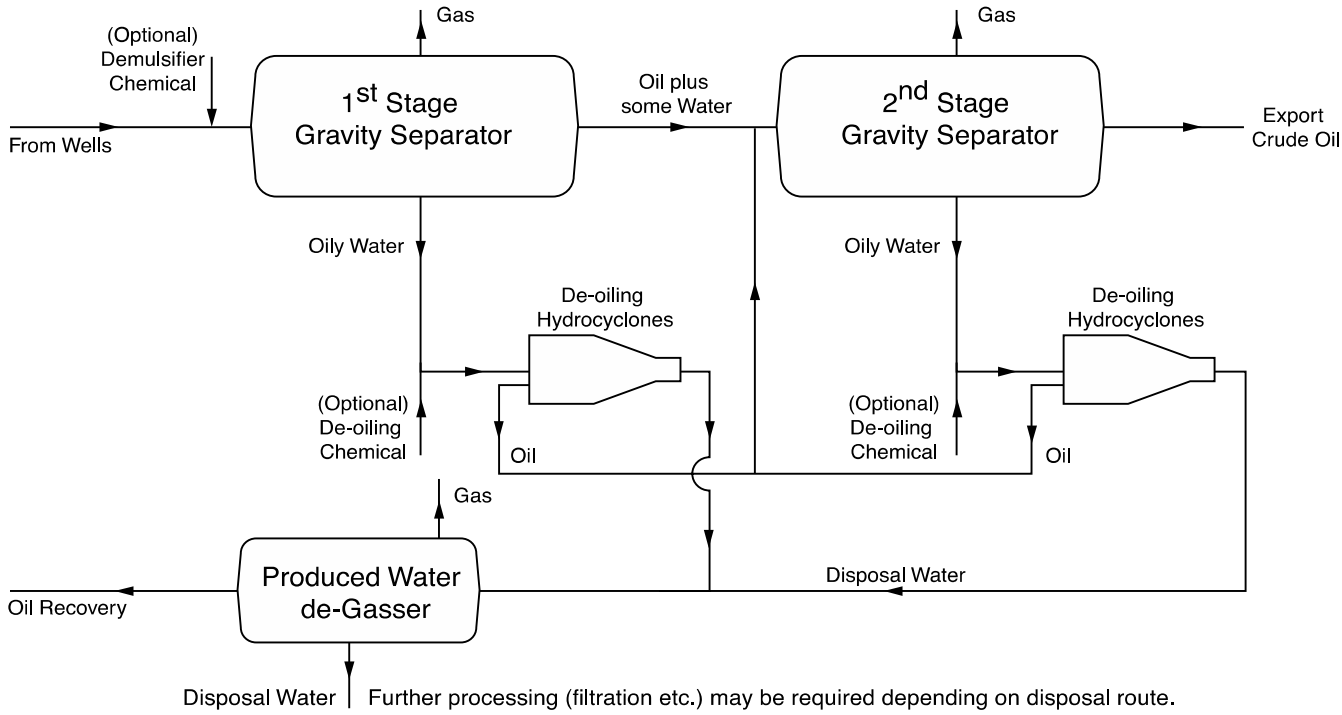


Figure 32 Modern scheme for separating oil from Produced Water.

9.6 Coalescer Units

There are a number of designs of coalescer units. The basic concept is to provide a (usually oleophilic) surface on which the small oil droplets can collect, grow and eventually break free and be removed for subsequent separation. They are capable of producing the lowest oil concentrations (5 ppm oil in water has been achieved in ideal circumstances). However, they are very susceptible to plugging by organic (wax, asphaltenes etc.) or inorganic solids (scale, formation material, corrosion products etc.). They can be (partially) regenerated by backwashing – though disposal of the backwash water may present a problem.

One design is to pack the coalescer vessel with granular, fibrous material. The (small) input oil droplets coalesce on the granular fibres. The resulting, larger oil droplets are separated downstream of the coalescer. A second type of coalescer is where the oily – water feed is passed down a filter tube. The properties of the semi-porous material are adjusted so that water can pass through it, concentrating the remaining oil/emulsion phases which can then be more efficiently processed by other means, such as gravity separators.

9.7 Centrifuges

Hydrocyclones are typically capable of removing 50% of the 10 μm diameter oil droplets rising to 100% of the 20 μm ones. The principle of combining gravitational and centrifugal forces employed by hydrocyclones can be further extended by use of centrifuges where an external electric motor is used to spin the fluid at high velocity together with suitably designed internals to promote oil/water separation. Experience has showed that centrifuges have the following advantages:

- More effective than hydrocyclones (complete removal of all oil droplets larger than 5 μm is claimed).
- Their operation is not dependent on the available fluid pressure drop.

The above has to be weighed against their increased space, weight, power and maintenance requirements.

9.8 Reducing Environmental Impact of Produced Water Discharge

The produced water can be either re-injected or disposed of. The environmental impact of produced water can be minimised by:

- Replacing the use of fresh injection water by produced water.
- Reducing the oil, solids and chemicals content of produced water.
- Reduce the volume of produced water by the means of production management solutions.

10. WATER INJECTION

Large volumes of water are injected into the sub-surface for pressure maintenance and improved oil recovery. For instance, North Sea light oil reservoirs, which might recover 20 - 30% of the original oil in place under primary recovery (pressure depletion) can have their recovery doubled to 40 - 50% by use of water injection. The processes involved are:

- Sweep of mobile oil from injection well to production well
- No loss of oil by maintaining formation pressure above the bubble point
- Improved cash flow/profitability by increasing early oil production and reducing the project lifetime
- Reduced or no requirement for artificial lift

The reservoir engineering study carried out as part of the field development plan will dictate where, how much, and at what rate the water should be injected. The task of the Production Technologist is to write the injection water specifications so that it will not be:

- Corrosive to the injection well and associated surface facilities and
- Compatible with the injection formation (e.g. by avoiding clay swelling) so that the injectivity is maintained over the injection project lifetime. Potential scaling in the production wells by studying the compatibility of the injection water with the formation water also needs to be taken into account when choosing injection water.

The principal factors which define the water quality are listed along with many of their likely effects and solutions to the resulting water quality issues in Table 13.

Issue	Effect	Treatment
Suspended solids	Plugging of injection formation	Filtration
Suspended oil	Plugging of injection formation (particularly in the presence of solids)	Hydrocyclones / Flotation / Filtration
Dissolved Gases {O_2 / CO_2 / H_2 S}	Corrosion of well and facilities. Plugging of formation by corrosion products	Degasification Corrosion inhibitor Injection
Formation of Solids {$CaCO_3$ / Ba SO_4 / $CaSO_4$ / FeS}	Equipment and formation plugging by scale	Scale inhibitor Injection
Bacteria {Aerobic / Anaerobic (sulphate reducing)}	Formation plugging by bacterial residues or corrosion production	Biocides
Injection water incompatible with formation and formation water	Loss of permeability of injection formation	Pretreat formation (clay stabilisers) Alter injection water chemistry

Table 13 Water Injection Quality Issues.

Large volumes (>30,000 bwpd) may be injected into each well while the total field requirements can be up to 1,000,000 bwpd in the case of giant oil fields.

10.1 Water Sources

Often several potential water supply sources are available. The water from the different sources will have different properties and will impose different treatment costs to make it suitable for injection. When a source is chosen, studies are required to determine that there is sufficient water available for the project lifetime. Sources include:

- Sea water
- Fresh surface water
- Aquifer water (not from the oil producing zone)
- Produced water (from the oil producing zone)

10.2 Injection Water Treatment

Figure 33 is an example of a typical process scheme – it employs coarse and fine filtration prior to de-oxygenation together with the addition of several inhibitors.

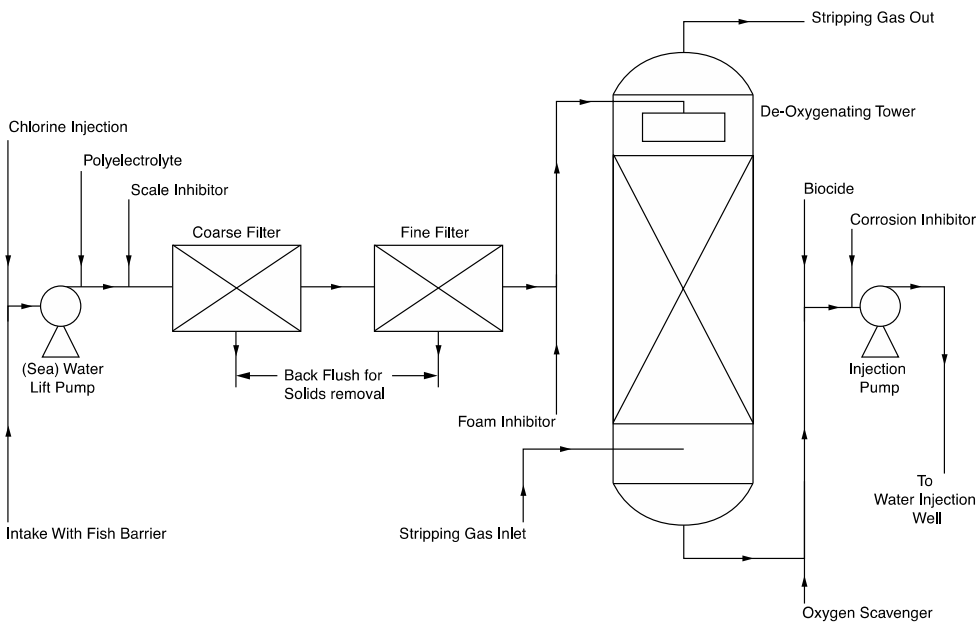


Figure 33 Injection process scheme with fine filtration.

The process scheme operates as follows:

The (sea) water lift pumps are protected from large solids and animals (e.g. fish) by barrier filters. Chlorine is injected into feed water in the suction of the lift pumps. The water is then pumped, after the addition of polyelectrolyte coagulant and scale inhibitor, to the coarse and then to the fine filters. The filters retain the solids while the chlorine kills the bacteria which could have led to microbial growth on the filters. The solids removed from the water will eventually block filters; these solids are removed by back-flushing (reversing the flow of process water) so that the filters' solids-removal capacity is regenerated. The filtered water, after the addition of a defoaming chemical if necessary, is pumped to the top of the de-oxygenating tower. Stripping gas is fed in at the bottom of the tower. A packed or trayed tower (Figure 34) is used to bring the water and gas into intimate contact to reduce the oxygen to the required level. The de-oxygenated water is drawn off at the bottom of the tower.

An alternative to gas stripping is to reduce the pressure to a low value and run the tower as a vacuum deaerator (Figure 34). Both these treatments do not completely reduce the oxygen to the very low levels required – this is achieved by the addition of an oxygen scavenger (e.g. sodium sulphite).

The water is now ready for pumping into the injection wells after further addition of scale inhibitors and biocides to ensure the injection water sterility.

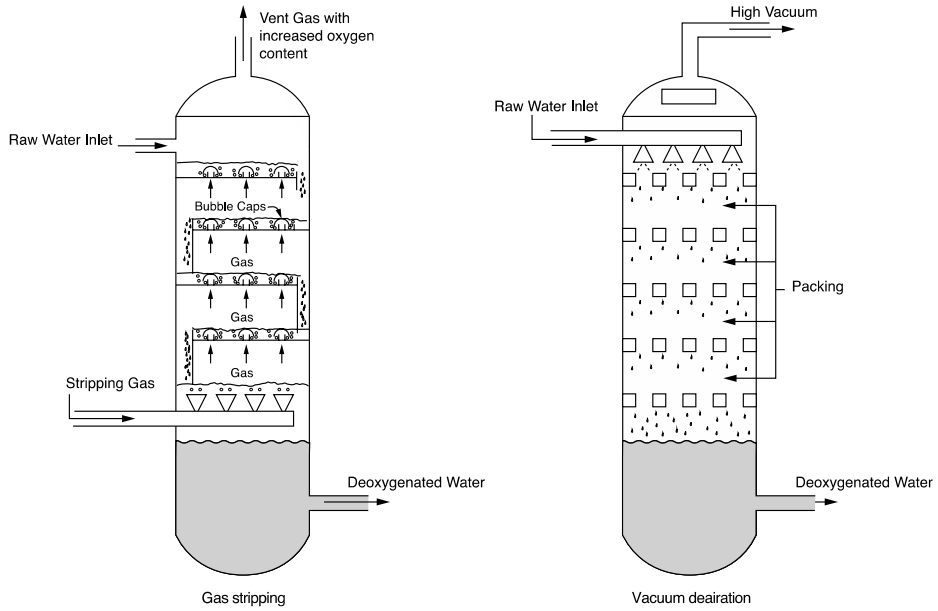


Figure 34 Deoxygenation of water.

11. FURTHER READING

1. "Surface Production Operations", Volume 1 (2nd Edition, 1998) and Volume 2 (1st Edition, 1989), by Arnold K and Stewart M.; Gulf publishing Company
2. "Oil and Gas Pipeline Fundamentals" by Kennedy J.; Penwell Books, 1993
3. "Hydrocarbon Exploration and Production", 2nd Edition, by Jahn F., Cook M. and Graham M; Elsevier Science, 2008
4. "Petroleum Production Engineering", 2nd Edition, by Guo, B., Liu, X., and Tan, X. Gulf Professional Publishing, 2017
5. "Petroleum Engineering Handbook for the Practicing Engineer", Volume 2 by Mian M. A.; PennWell Books, 1992.

TIME ZONE 1

HERIOT WATT UNIVERSITY

SCHOOL OF ENERGY, GEOSCIENCE, INFRASTRUCTURE & SOCIETY

Petroleum Engineering

G11PT

Production Technology MODEL EXAM

Semester X – 20XX

Date: XXX Time:

Duration: 3 Hours

1. This paper has 5 questions. Attempt any 4 numbered questions from these 5. Each question has equal weighting with a total of 25 marks with the marks for each section shown in brackets

2. If more questions are attempted than stated above, they will be marked in the order they appear in the scripts until the requisite number has been marked. All remaining answers will be disregarded.

3. You should clearly show any use you make of the Tubing Performance and other charts provided in this exam paper. State clearly any assumptions used and intermediate calculations made in numerical questions. No marks can be given for an incorrect answer if the method of calculation is not presented. If you have used the charts please detach them from the question paper and append them to your answer book.

4. Unit Conversion Tables are included.

Attached: Appendices with charts

Calculator Permitted	Yes
Open Book	No
Course Notes Permitted	No

DO NOT REMOVE THIS PAPER FROM THE EXAM HALL

Question 1

1.A Explain what is annulus heading and why it is technically detrimental.

[4 marks]

1.B Horizontal Wells have become a very popular well construction option over the last few years. Draw a simple sketch that illustrates the terms “Build Radius”, “Heel” and “Toe” and “Standoff” from a fluid contact.

[4 marks]

1.C A vertical Subsea exploration well has found a reservoir containing a 30 m oil (33º API gravity) rim sandwiched between a gas cap and an aquifer. The very high permeability, low-strength, C-sand is tilted at an angle of 15º. It is proposed to develop the field with this single well tied back to a production facility with a limited gas and water handling capacity. An open-hole completion has been proposed as a low cost completion.

1. Do you recommend an open-hole completion? If not, recommend an alternative completion type.
2. Briefly explain the reasons behind your recommendation
3. What type of completion is preferred if the C-sand was consolidated (i.e. had a high rock strength)

[6 marks]

1.D A sand fill is blocking the tubing. List what types of well intervention can be used to clean it out in a live well. Select any two types and explain how the clean out can be carried over.

[6 marks]

1.E Explain why measured wellbore temperature profile can be used to locate the intervals of cement placement.

[5 marks]

Question 2

2.A The flow characteristics of a hydrocarbon in a vertical tubing string vary as the position of the fluid in the tubing varies. Describe the first three (from the bottomhole up) flow regimes that would be encountered in a well producing fluid from a reservoir containing oil and dissolved gas. Explain how they affect the pressure loss. Assume the flowing bottomhole pressure is above the bubble point pressure.

[10 marks]

2.B Explain what is slip effect and liquid hold-up and how they are related.

[5 marks]

2.C 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 operating flow rate and bottomhole flowing pressure. Use Figures 1-4 In the Appendix. *(Show how you have used the charts, detach them from the question paper and append them to the answer book.)*

[10 marks]

Question 3

3.A List up to 4 key features for both Rod Pumps and Gas Lift that form the basis of the following statement:
"Worldwide, 85% of Artificial Lift equipment installed is rod pumps. This is mainly in stripper (i.e. low production) wells while gas lift is the most popular artificial lift technique for higher rate wells".

[8 marks]

3.B Most gas lift fields have insufficient gas to lift all the wells at their (technical) maximum production. Briefly describe the process of optimal allocation of available lift gas; mentioning the key economic parameters involved.

[5 marks]

3.C Design a gas lift installation for the following conditions:

Tubing	3.958 in
Required Production Rate	3000 STB/day
Oil Cut	100%
Gas Oil Ratio	100scf/bbl
Gas Specific Gravity	0.65
Average Flowing Temperature	150 °F
Reservoir Productivity Index	4 bpd/psi
Reservoir Depth	10,000 ft
Reservoir Pressure	3400 psi
Lift Gas Injection Gradient	20 psi/1000 ft
Minimum flowing tubing head pressure to transfer fluids to facility	250 psi
Dead Oil Density	35° API or 0.368 psi/ft
Gas Oil Ratio	100 scf/bbl
Brine Density	0.44 psi/ft
Lift Gas Injection Rate	3,000,000 scf/d

A pressure traverse curve is provided as Figure 5 in Appendix B. *(Show how you have used the chart, detach it from the question paper and append to the answer book.)*
Assume that the well is closed in with dead oil in the tubing and brine in the casing/tubing annulus.

(i) does this well require artificial lift to produce?

[3 marks]

(ii) what depth should the gas lift valve be installed in a single valve lift installation in order to achieve the required production?

[5 marks]

HINT: Note that the relevant portions of the pressure traverse curve can be approximated by straight lines.

(iii) what is the minimum surface gas injection pressure to kick the well off in the configuration described?

[3 marks]

(iv) how does this change if dead crude oil was present in the casing/tubing annulus instead of brine?

[1 marks]

Question 4

4.A Zero (0°) phasing perforation often results in poorer inflow performance. However, 0° phasing guns are common. Explain why.

[5 marks]

4.B List 2 sources of formation damage encountered during drilling and completion operations and 2 damage sources during production operations. Briefly indicate how the fluid selection for a (matrix) removal treatment will be influenced by the damage source (examples may clarify your answer).

[6 marks]

4.C A well completed on 40 acre spacing (r_e = 745 ft) has a damaged region extending 1 ft beyond the wellbore (rw = 0.328 ft).

The Hawkins formula may be used to calculate the skin due to formation damage:

$$S = \left(\frac{k}{k_d} - 1\right)\ln\left(\frac{r_d}{r_w}\right)$$

while the productivity ratio {J impaired or damaged / J original or Ji/Jo } of the well with and without the above formation damage is given by:

$$\frac{J_i}{J_o} = \frac{\ln {r_e}/{r_w}}{\ln {r_e}/{r_w} + S}$$

Use the above to illustrate the statement:

{"Formation Damage reduces well productivity greatly while the stimulation effect of increasing the near wellbore permeability above the initial value has limited effect".}

HINT : estimate the relative well productivity with some arbitrary values of reduced permeability, e.g. 95%, 75%, 50% formation damage as well as 10 times increase in near wellbore formation permeability.

[8 marks]

4.D Briefly contrast the objectives and generalised selection criteria for matrix acidizing and fracturing treatments when considering carrying out a stimulation treatment on a well.

[6 marks]

Question 5

5.A Your service company has designed the following fracturing treatments:

Wellbore radius (rw):	0.328 ft
Reservoir height:	100 ft; bounded by competent shales
Reservoir Permeability:	0.1 mD
Proppant available:	300,000 lb

Design Fracture Conductivity (kf*w):

treatment A - 1500 mD.ft at 4 lb/ft2 proppant loading

treatment B - 850 mD.ft at 2 lb/ft2 proppant loading

(i) Use the accompanying graph (Figure 6 in Appendix C) to advise management as to whether treatment A or B will give the highest well productivities.

[6 marks]

(ii) Why would you expect one of these treatments to be more efficient?

[1 marks]

5.B Explain why sand production may start after water breakthrough.

5.C

(i) Sketch the main components of a 3-phase (gas/oil/water) horizontal separator and briefly (one sentence) explain the function of each of the main components.

[6 marks]

(ii) Indicate how the export of the oil/water/gas flows are controlled and why the outlets are situated at your indicated locations.

[4 marks]

5.D

(i) Stokes Law (below) describes the velocity of separation (V) of one liquid from another

$$V = \frac{kD^2(\rho_d - \rho_c)}{\mu_c}$$

Where D is the droplet size, ρ the density, μ the viscosity and c and d refer to the continuous and discontinuous phases respectively. An oil/water 2-phase

separator has been in use in a field for many years. The main producing zone (35˚ API, saline formation water) is now depleted and it is proposed to produce a shallower, subsidiary zone (17˚ API oil, fresh formation water). The required data are given in Table 1.

You are required to advise management as to whether the existing separator capacity is sufficient when the subsidiary zone is producing at 1% and 75% water cut.

Table 1.

Fluid properties at separator conditions		Production zone	
		Main Sand	Subsidiary Sand
Oil	viscosity cp	2.5	40
	density/g.cm^{-3}	0.85	0.95
Water	viscosity cp	0.9	0.7
	density/g.cm^{-3}	1.1	0.99

N.B. The production rate from the subsidiary zone is only 10% of that achieved from the main zone.

[6 marks]

(ii) Indicate two remedial actions that could be taken to maintain the separation capacity.

[2 marks]

END OF PAPER

Unit Conversion Tables

1. Alphabetical List of Units

To convert from	To	Multiply by
acre	meter^2(m^2)	4.046873E+03
atm	MPa	1.013250E-01
atmosphere	pascal (Pa)	1.013250E+05
bar	pascal (Pa)	1.000000E+05
bar	MPa	1.000000E-01
barrel	meter^3	1.589873E-01
bbl/day	meter^3/day	1.589873E-01
centimeter of mercury (0C)	pascal (Pa)	1.333220E+03
centimeter of water (4C)	pascal (Pa)	9.806380E+01
centipoise	pascal second (Pas)	1.000000E-03
centistokes	meter^2 per second (m^2/s)	1.000000E-06
cp	Pas	1.000000E-03
cSt	mm^2/s	1.000000E+00
cu in	meter^3(m^3)	1.638706E-05
cubic yard	meter^3(m^3)	7.645549E-01
darcy	m^2	9.869233E-13
degree (angle)	radian (rad)	1.745329E-02
degree API	g/cm^3	141.5/(131.5+˚API)
degree Celsius	kelvin (K)	$T_k = T_c + 273.15$
degree Fahrenheit	degree Celsius	$T_c = (T_F - 32)/1.8$
degree Fahrenheit	kelvin (K)	$T_k = (T_F + 459.67)/1.8$
degree Rankine	kelvin (K)	$T_k = T_R /1.8$
dyne	newton (N)	1.000000E-05
dyne cm	newton meter (Nm)	1.000000E-07
dyne/cm^2	pascal (Pa)	1.000000E-01
foot	in (inch)	1.200000E+01
foot	meter	3.048000E-01
foot of water (39.2F)	pascal (Pa)	2.988980E+03
ft lbf	joule (J)	1.355818E+00
ft lbf/hr	watt(W)	3.766161E-04
ft lbf/min	watt(W)	2.259697E-02
ft lbf/s	watt(W)	1.355818E+00
ft/hr	meter per second (m/s)	8.466667E-05
ft/min	meter per second (m/s)	5.080000E-03
ft/s	meter per second (m/s)	3.048000E-01
ft/s^2	meter per second^2 (m/s^2)	3.048000E-01
ft^2	meter^2(m^2)	9.290304E-02
ft^3	meter^3(m^3)	2.831685E-02
g/cm^3	kilogram per meter^3 (kg/m^3)	1.000000E+03
gallon (U.K.Liquid)	meter^3 (m^3)	4.546092E-03
gallon (U.S.Liquid)	meter^3 (m^3)	3.785412E-03
hour	second	3.600000E+03
hydraulic horsepower hhp	kW	7.460430E-01
inch	meter	2.540000E-02
inch	meter (m)	2.540000E-02

inch of mercury (32F)	pascal (Pa)	3.386380E+03
inch of mercury (60F)	pascal (Pa)	3.376850E+03
inch of water (39.2F)	pascal (Pa)	2.490820E+02
inch of water (60F)	pascal (Pa)	2.488400E+02
kelvin	degree Celsius	$T_c = T_k - 273.15$
kgf m	newton meter (Nm)	9.806650E+00
kgf s^2/m (mass)	kilogram (kg)	9.806650E+00
kgf/cm^2	pascal (Pa)	9.806650E+04
kgf/m^2	pascal (Pa)	9.806650E+00
kgf/mm^2	pascal (Pa)	9.806650E+06
kilogram force (kgf)	newton (N)	9.806650E+00
kilogram mass (kgm)	lbm	4.420751E-02
kilowatthour (kW hr)	joule(J)	3.600000E+06
km/hr	meter per second (m/s)	2.777778E-01
lbf	N	4.448222E+00
lbf/in^2	GPa	6.894757E-06
lbm	kilogram (kg)	4.535924E-01
lbm	kg	4.535924E-01
lbm/ft^3	kg/m^3	1.601846E+01
litre	meter^3(m^3)	1.000000E-03
micron	meter (m)	1.000000E-06
mile	meter (m)	1.609300E+03
millibar	pascal (Pa)	1.000000E+02
millidarcy	m^2	9.869233E-16
μs/ft	μs/m	3.280840E+00
ohm centimeter	ohm meter (Ωm)	1.000000E-02
pascal (Pa)	psi	1.451000E-04
poise	pascal second (Pas)	1.000000E-01
pound force (lbf)	newton (N)	4.448222E+00
ppg	psi/ft	5.200000E-02
psi	MPa	6.894757E-03
psi/ft	kPa/m	2.262059E+01
psi^{-1}	Pa^{-1}	1.450377E-04
scf/bbl	standard m^3/m^3	1.801175E-01
sq in	meter^2(m^2)	6.451600E-04
stokes	meter^2 per second (m^2/s)	1.000000E-04
tonne	kilogram (kg)	1.000000E+03
ton (UK)	kilogram (kg)	1.016047E+03
watt	Js^{-1}	1.000000E+00
yard	foot	3.000000E+00

2. SI Unit Prefixes

multiplication factor	SI prefix	Symbol
10^{18}	exa	E
10^{15}	peta	P
10^{12}	tera	T
10^{9}	giga	G
10^{6}	mega	M
10^{3}	kilo	k
10^{2}	hecto	h
10	deka	da
10^{-1}	deci	d
10^{-2}	centi	c
10^{-3}	milli	m
10^{-6}	micro	µ
10^{-9}	nano	n
10^{-12}	pico	p
10^{-15}	femto	f
10^{-18}	atto	a

Appendix A (charts related to Question 2)

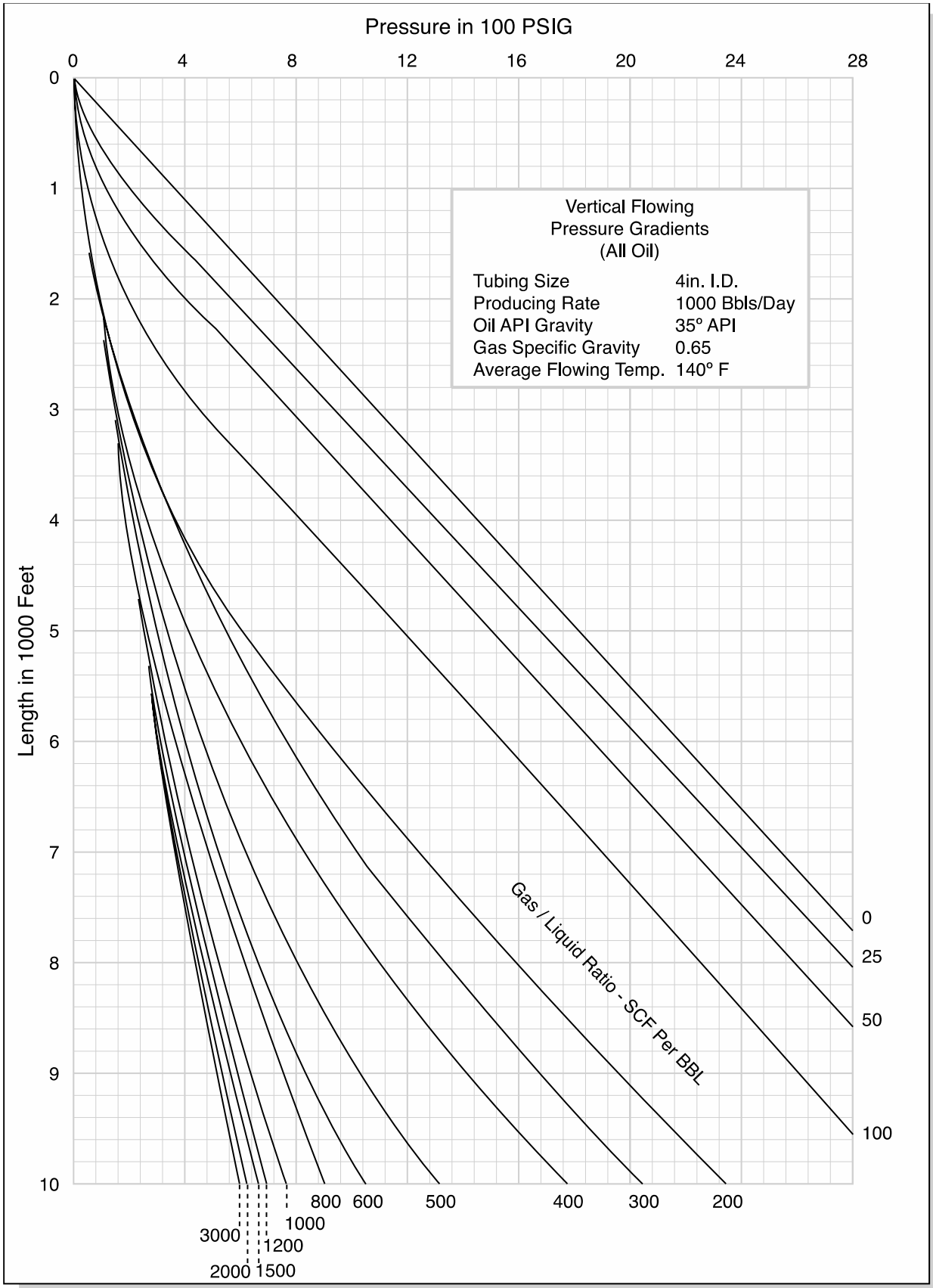
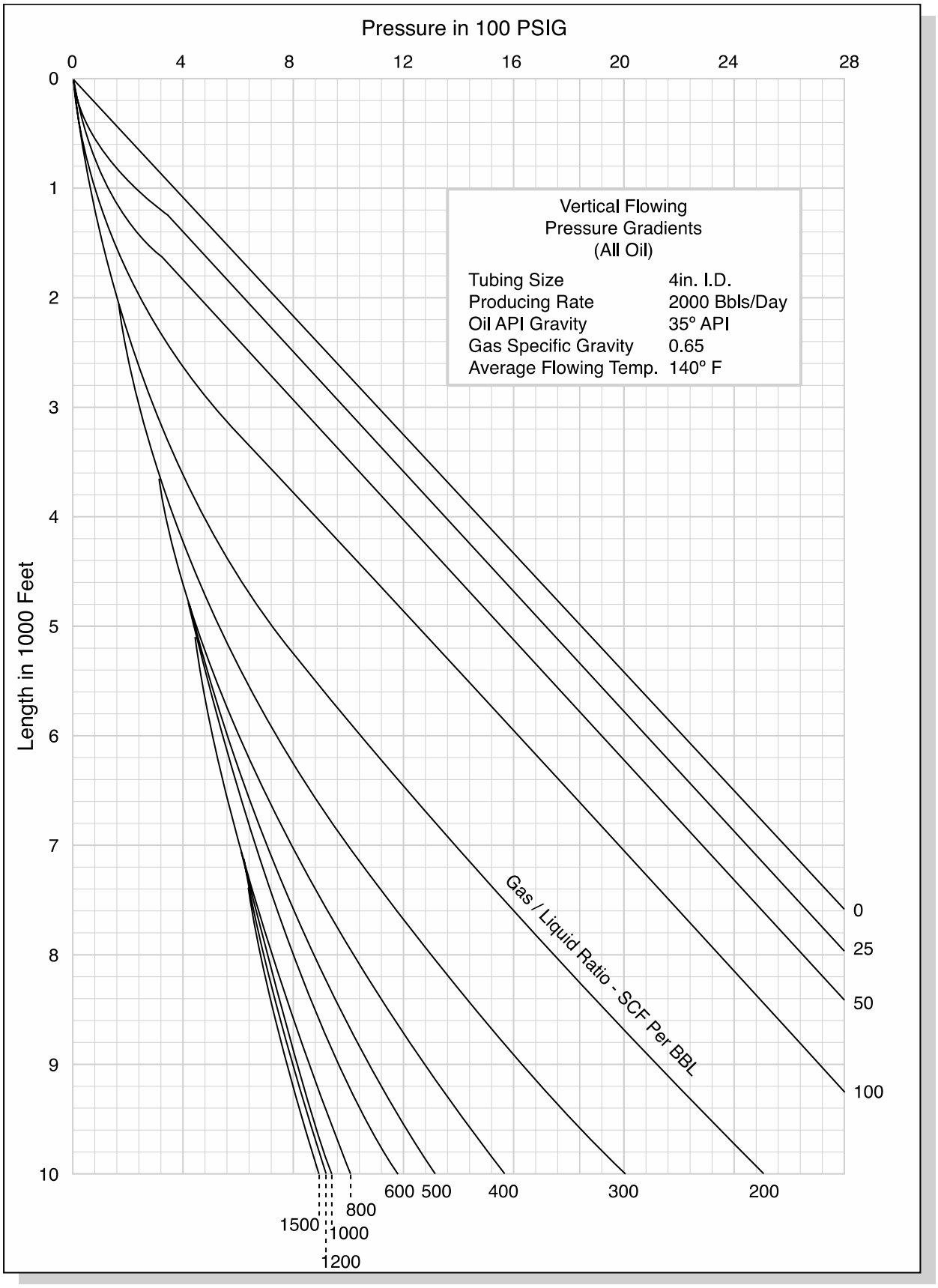


Figure 1


Pressure in 100 PSIG
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8
12
16
20
24
28
Length in 1000 Feet
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Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 2000 Bbls/Day
Oil API Gravity 35° API
Gas Specific Gravity 0.65
Average Flowing Temp. 140° F
Gas / Liquid Ratio - SCF Per BBL
0
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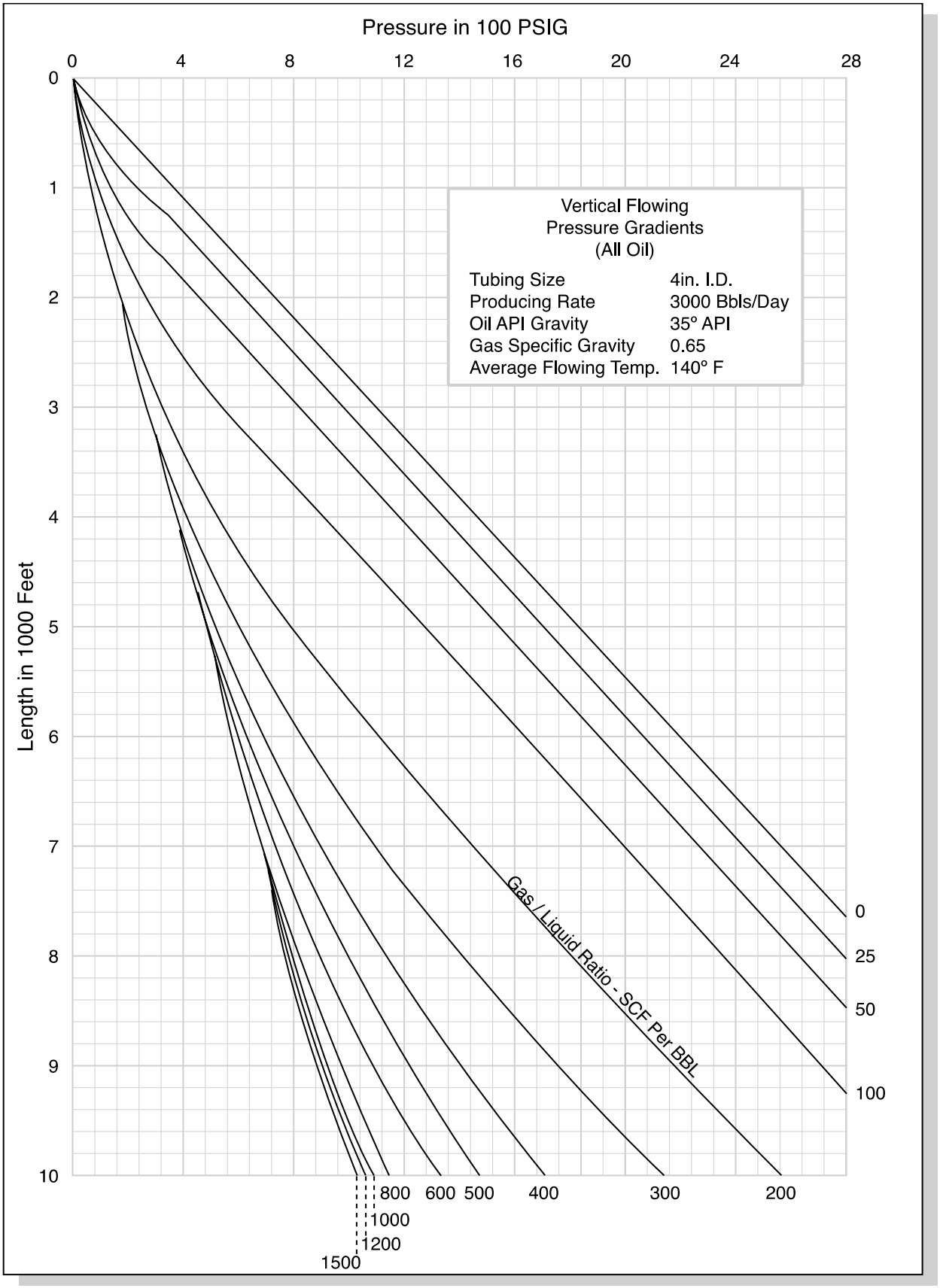
Figure 2


Pressure in 100 PSIG
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Length in 1000 Feet
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Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 3000 Bbls/Day
Oil API Gravity 35° API
Gas Specific Gravity 0.65
Average Flowing Temp. 140° F
Gas / Liquid Ratio - SCF Per BBL
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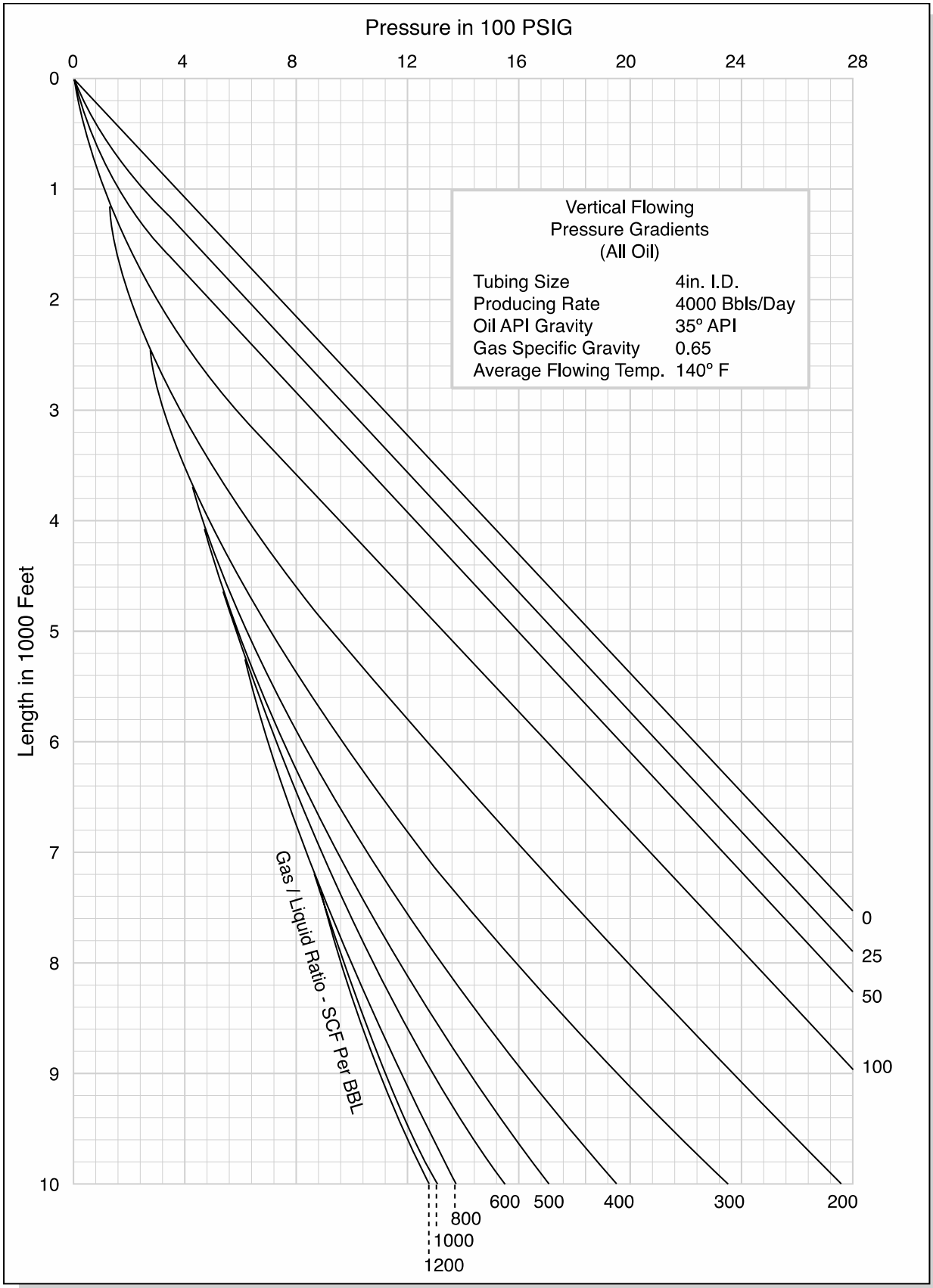
Figure 3


Pressure in 100 PSIG
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Length in 1000 Feet
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Vertical Flowing
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Average Flowing Temp. 140° F
Gas / Liquid Ratio - SCF Per BBL
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Figure 4

Appendix B (chart related to Question 3)

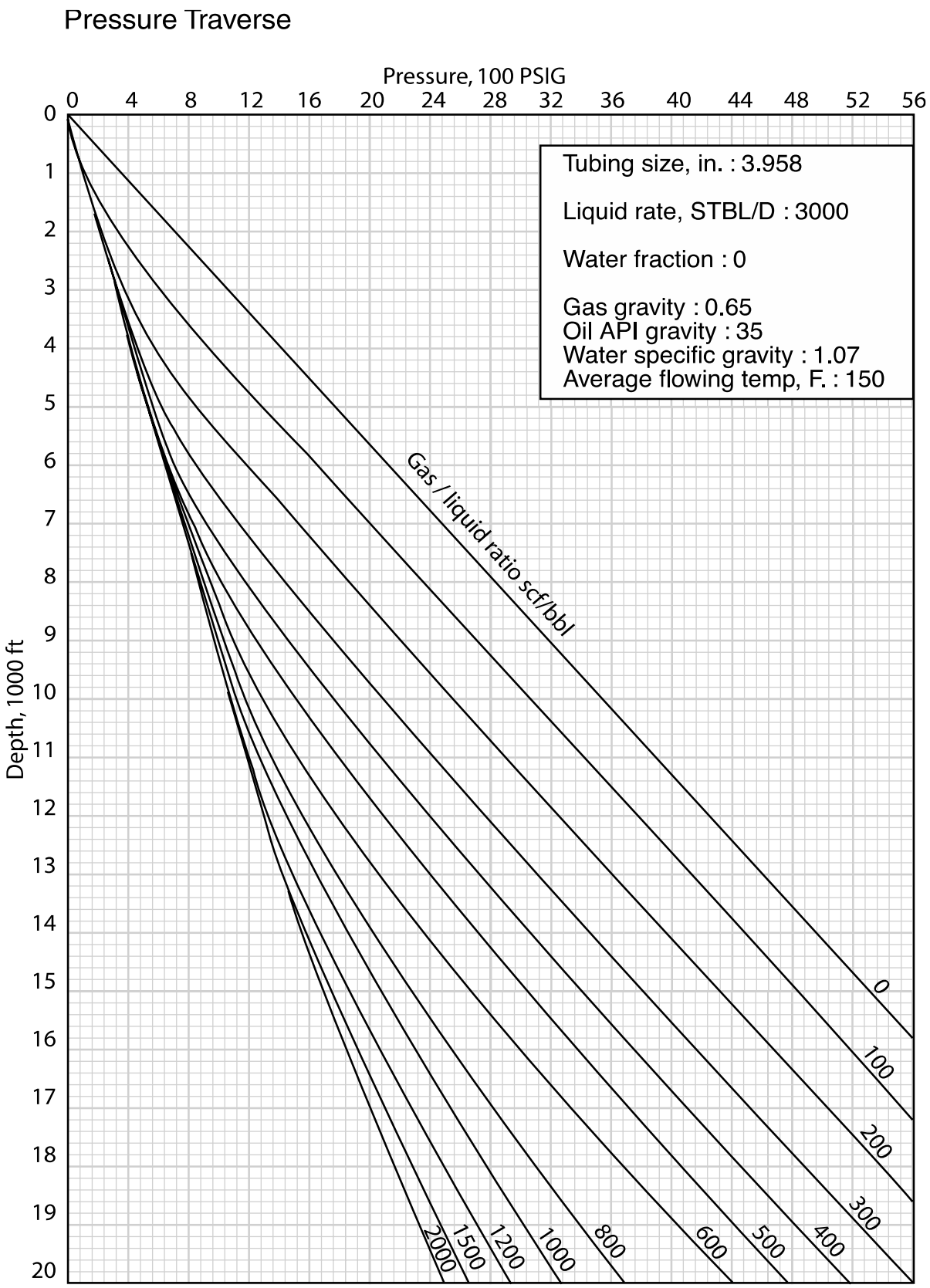
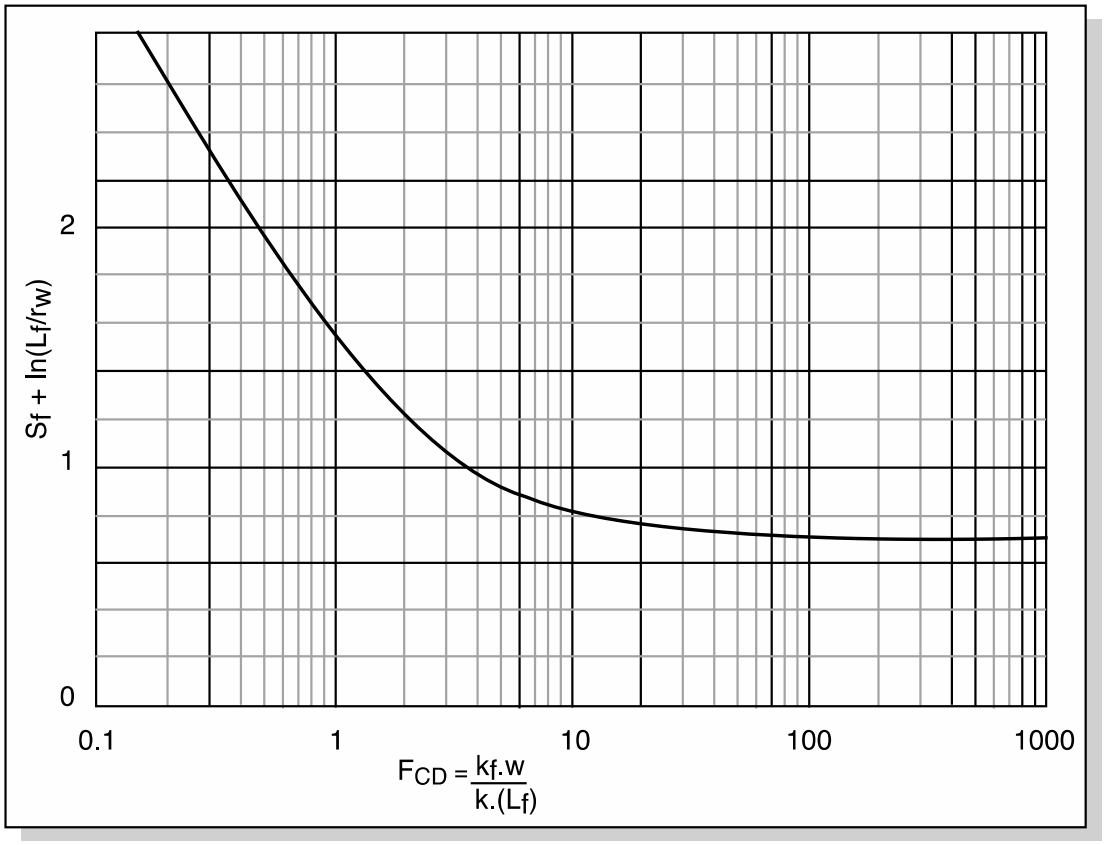


Figure 5

Appendix C (chart related to Question 5)



L_f is fracture half length

Fracture skin effect varying with fracture conductivity.
(From Cinco-Ley and Samaniego, 1981.)

Figure 6

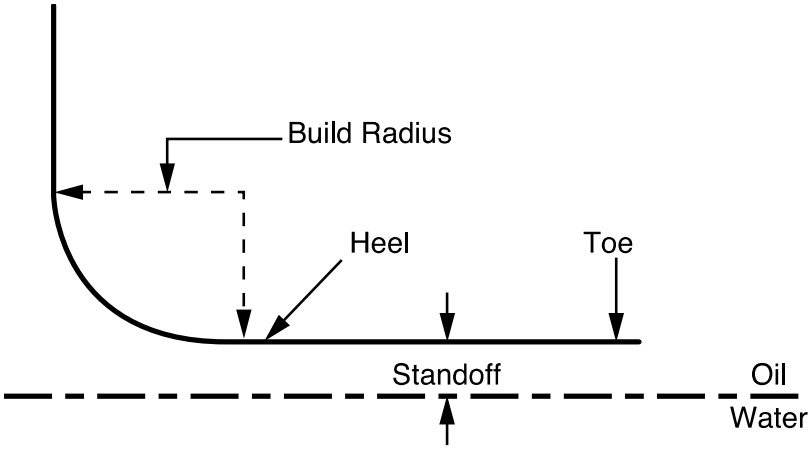
MODEL EXAM SOLUTIONS

Solution to Question 1:

1.A.

When the tubing annulus is fully or partly open to the production gas-liquid flow it may start filling with gas. Once it is filled it can start releasing some volumes of gas (gas slugs) into the tubing, often causing severe pressure and production phase oscillations. The outcomes of this include unstable production and transportation equipment exposed to unfavourable, cyclic conditions; and less efficient fluid separation

1.B.



1.C.

1 & 2. An Openhole completion has no selectivity to control water or gas production. Inflow selectivity can be achieved by a cemented casing with careful positioning of the perforations

3. A perforated cemented casing is still preferred for the above reasons.

1.D.

By wireline, Coiled Tubing and snubbing

Wireline: a sand bailer can be run and collect the sand with the aid of jarring.

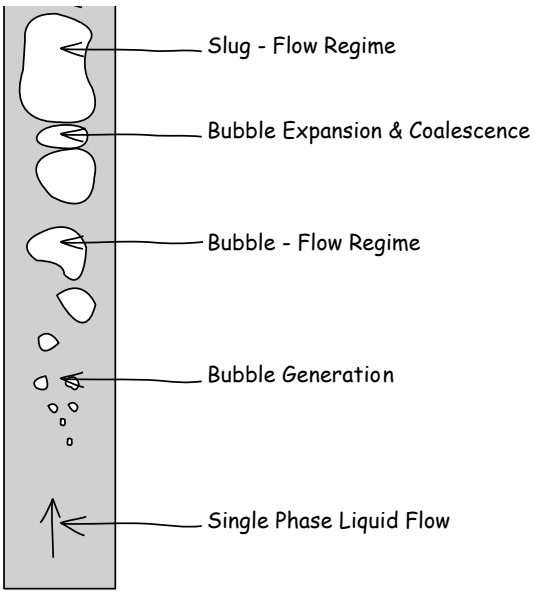
Coiled tubing; run to the top of the fill and circulate it out.

1.E.

Cement hardening is an exothermic reaction releasing heat and increasing the cement's temperature, which can be detected.

Solution to Question 2:

2.A.



(1) The oil enters the tubing at a flowing pressure above the bubble point and hence no separate gas phase exists. 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.

(2) 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.

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

(i) Slight expansion of the liquid phase

(ii) Evolution of additional gas.

(iii) Expansion of the existing gas phase

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.

This section of the tubing would demonstrate a continuously declining pressure gradient provided the decrease in the hydrostatic component exceeded the increasing frictional gradient

2.B.

The slip effect takes place in multiphase flow situations: one phase can move faster than the other. E.G. slippage occurs in liquid-gas mixtures where the gas flow velocity is higher than that for the liquid, mainly due to the buoyancy forces acting on the lighter gas phase.
Liquid hold-up is the volume fraction of pipe (or average fraction of pipe internal cross-section) occupied by liquids in-situ.
The faster moving gas requires less area to flow, so the slippage causes the liquid hold-up to increase. This results in the higher volume of pipe occupied by liquids and, as a result, in higher weight of the fluid column (i.e. hydrostatic head).

2.C.

i) The Productivity Index is described by the formula: $PI = q / (P_{res}-P_{wf})$

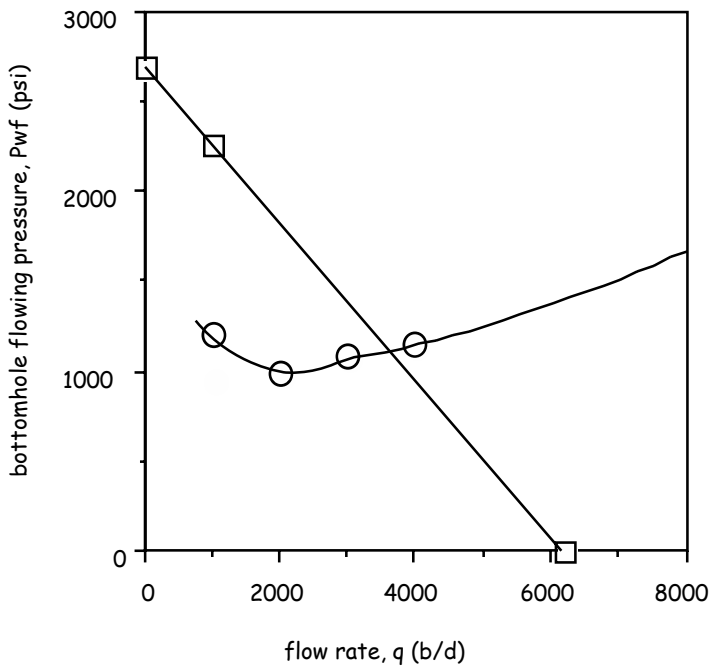
The Inflow Performance Relationship is developed by assuming several flow rates

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:

Flow rate, b/d	1000	2000	3000	4000
Equivalent depth of top of tubing, ft	2800	2100	1800	1500
Equivalent depth of bottom of tubing, ft	8800	8100	7800	7500
Flowing bottomhole pressure, psi	1360	1000	1085	1160

The IPR and the OPR are plotted below



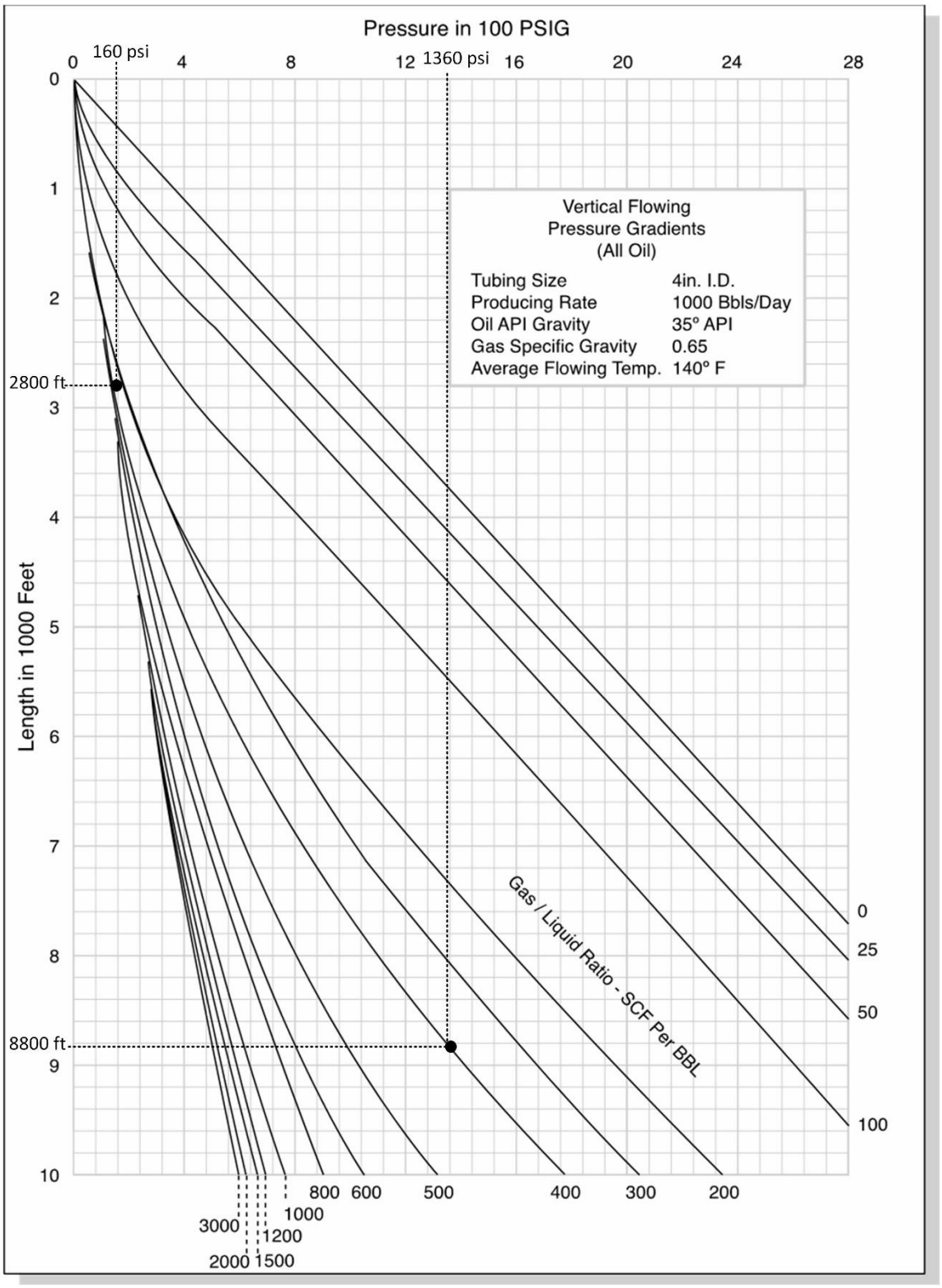
The operating point is where the two curves intersect: 3602b/d, 1134psi in the plot

Also check:

$$P_{wf} = \overline{P}_r - \frac{q}{PI}$$

$$P_{wf} = 2700 - \frac{3602}{2.3}$$

= 1134psi


Pressure in 100 PSIG
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160 psi
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1360 psi
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Length in 1000 Feet
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2800 ft
8800 ft
Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 1000 Bbls/Day
Oil API Gravity 35° API
Gas Specific Gravity 0.65
Average Flowing Temp. 140° F
Gas / Liquid Ratio - SCF Per BBL
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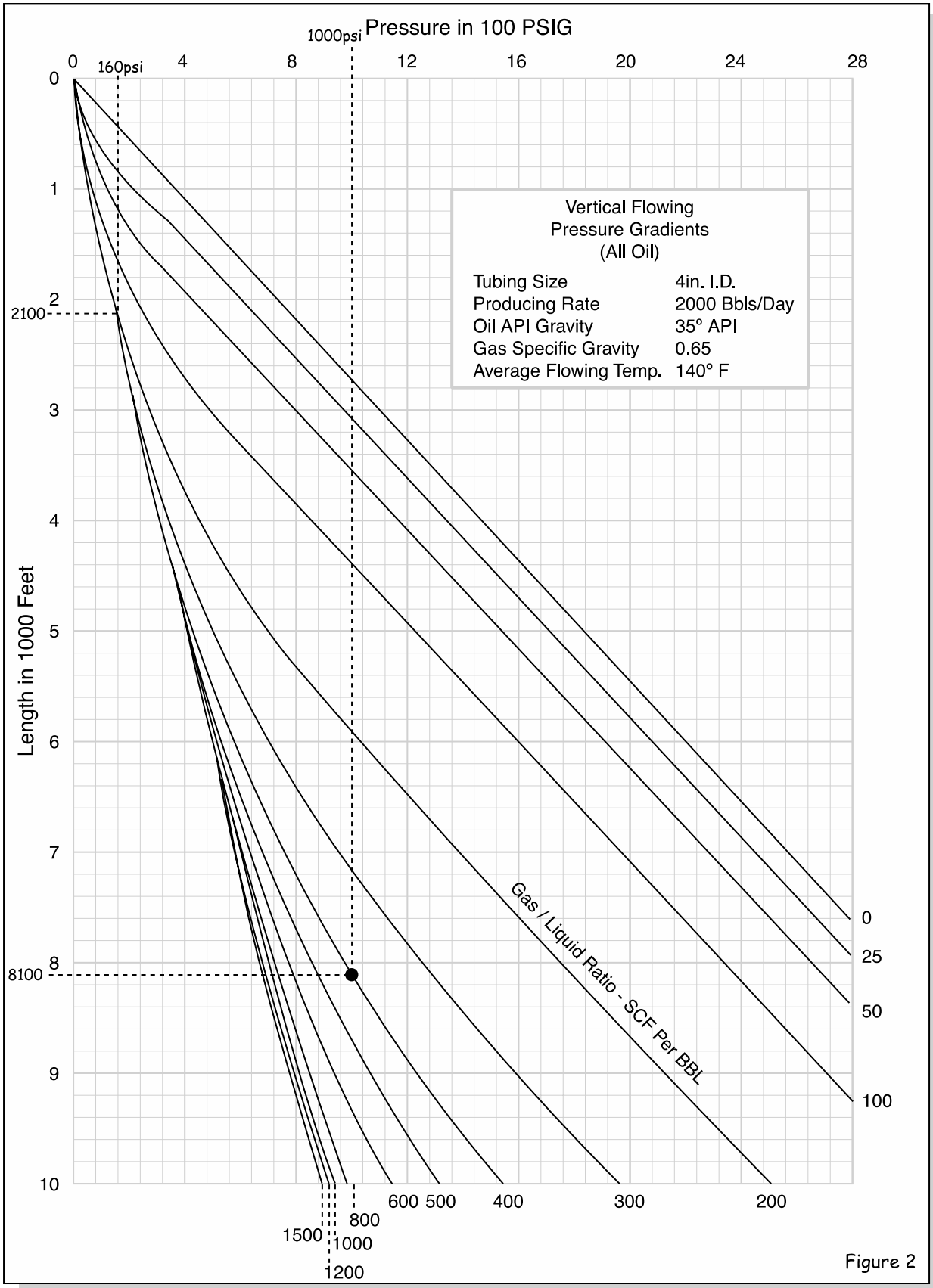
Pressure in 100 PSIG
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Pressure Gradients
(All Oil)
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Producing Rate 2000 Bbls/Day
Oil API Gravity 35° API
Gas Specific Gravity 0.65
Average Flowing Temp. 140° F
Gas / Liquid Ratio - SCF Per BBL
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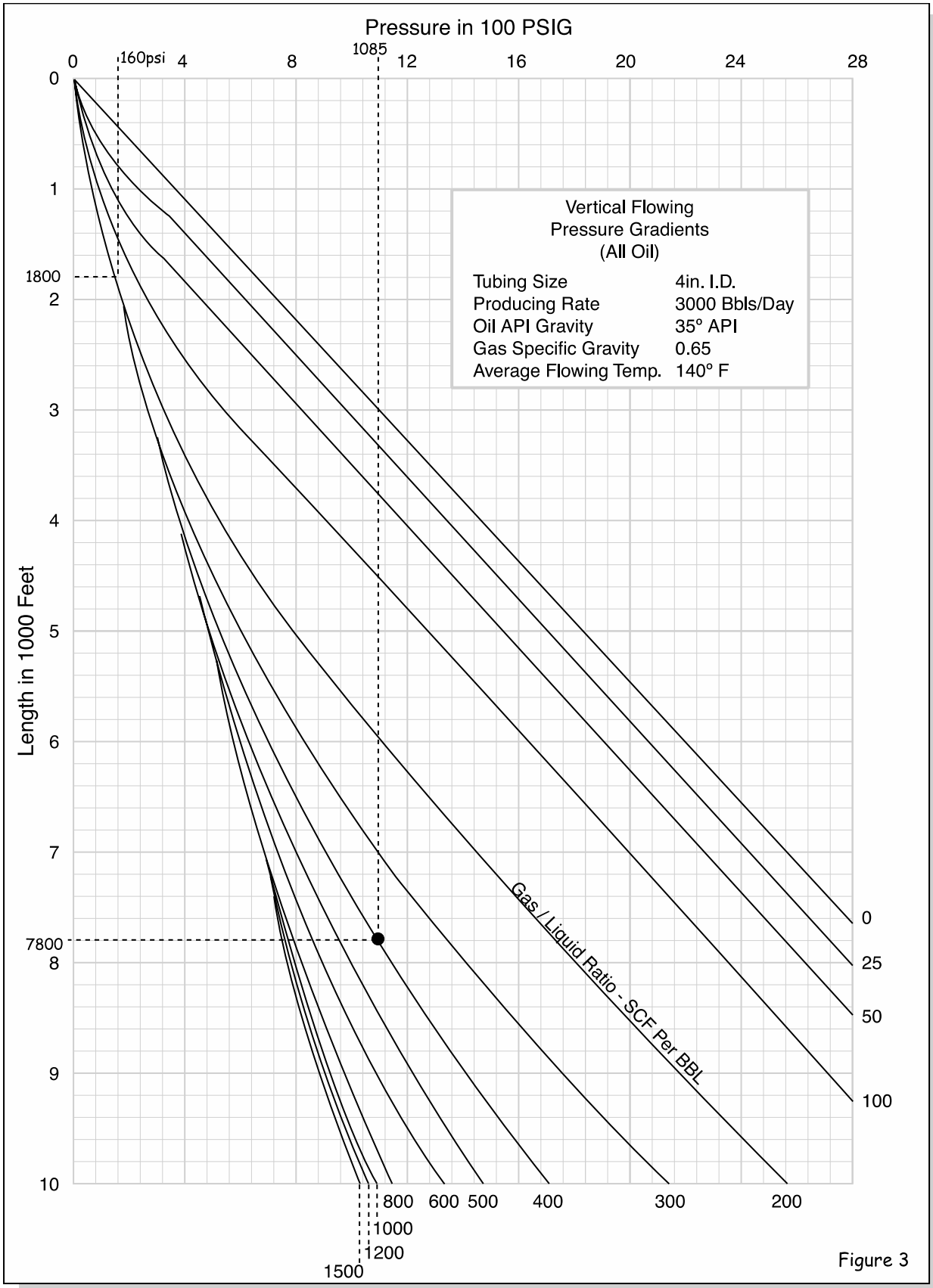
Figure 2


Pressure in 100 PSIG
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Length in 1000 Feet
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Pressure Gradients
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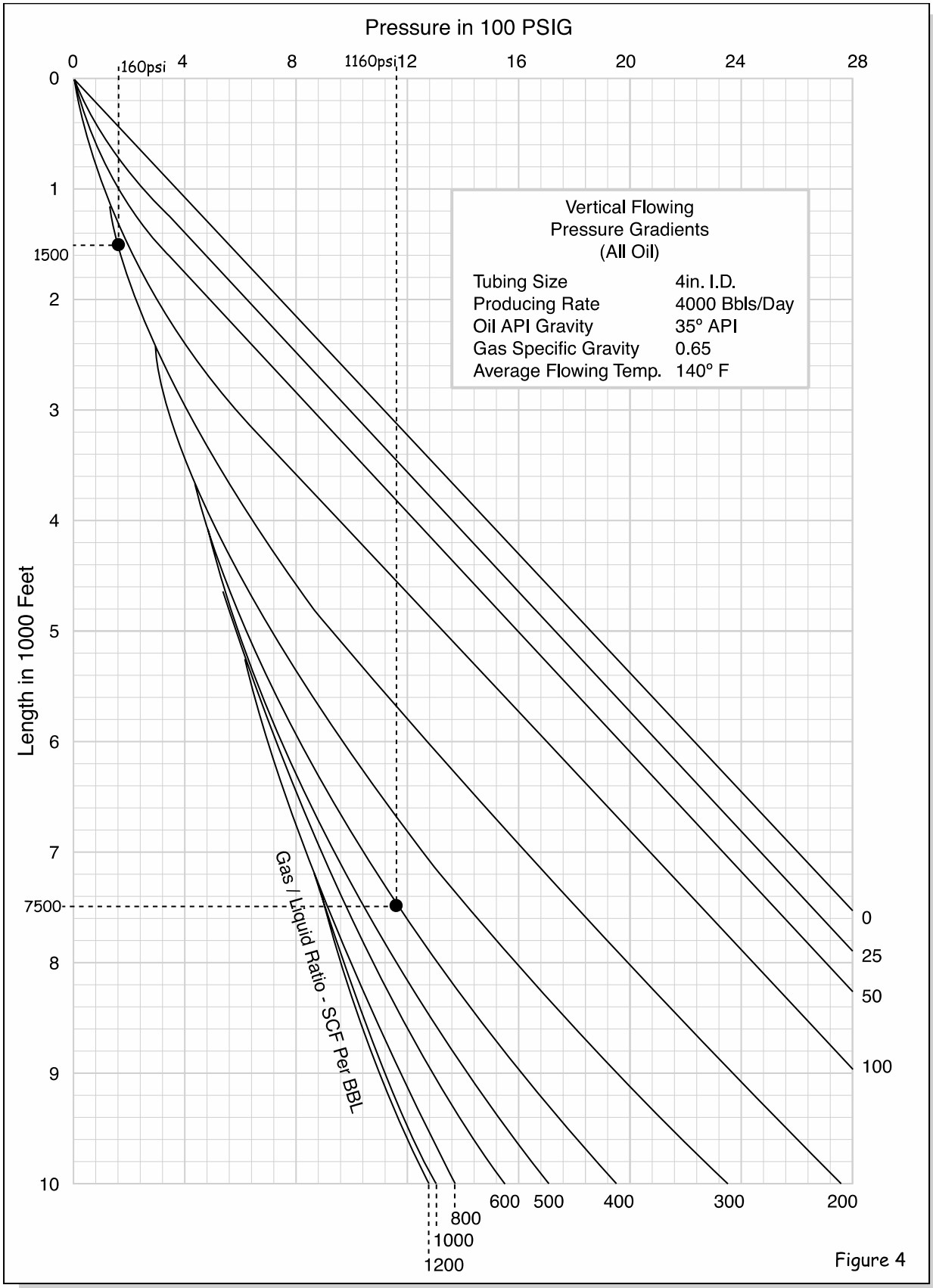
Figure 3


Pressure in 100 PSIG
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1160psi
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Length in 1000 Feet
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Vertical Flowing
Pressure Gradients
(All Oil)
Tubing Size 4in. I.D.
Producing Rate 4000 Bbls/Day
Oil API Gravity 35° API
Gas Specific Gravity 0.65
Average Flowing Temp. 140° F
Gas / Liquid Ratio - SCF Per BBL
0
25
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100
200
300
400
500
600
800
1000
1200

Figure 4

. **Solution to Question 3:**

3.A.

Rod Pump

- Typically low rates and moderate depths
- Relatively cheap to install & run
- Rod pumps are mechanically simple to operate and easy to repair/ maintain/replace. Can be operated by inexperienced personnel
- Pump performance can be monitored

Gas Lift

- Capable of high production rates
- Suitable for water drive reservoirs with relatively high bottomhole pressure gradients
- Flexible - valve settings can be adjusted for optimum performance based on actual, well conditions
- Can be used off-shore
- Fully open tubing giving access for logging
- Can handle (tolerate) produced solids e.g. reasonable formation sand concentrations
- High GOR => advantage rather than a drawback

N.B. Only 4 items are required from each of the above lists. Items exceeding 4 may be disregarded by the Marker..

3.B

- A brief description of the process is as follows:

- Perform a gas lift tubing performance calculation with a range of injected gas flow rates for each well in the field. Then, plot the results on a curve of liquid flow rate achieved versus injected gas rate.
- Calculate the incremental oil production rate in each well for each extra increment of gas injected.
- Allocate each increment of gas to that well with the highest incremental oil production until all gas allocated.
- Check economic limit, when cost of incremental lift gas equals income from incremental oil not exceeded

3.C

i

Yes.

Dead oil in tubing height 3,400 / 0.368 = 9,239 ft

Fluid level = 10,000 - 9,239 = 761 ft

Well is dead with fluid level at 761 ft

ii.

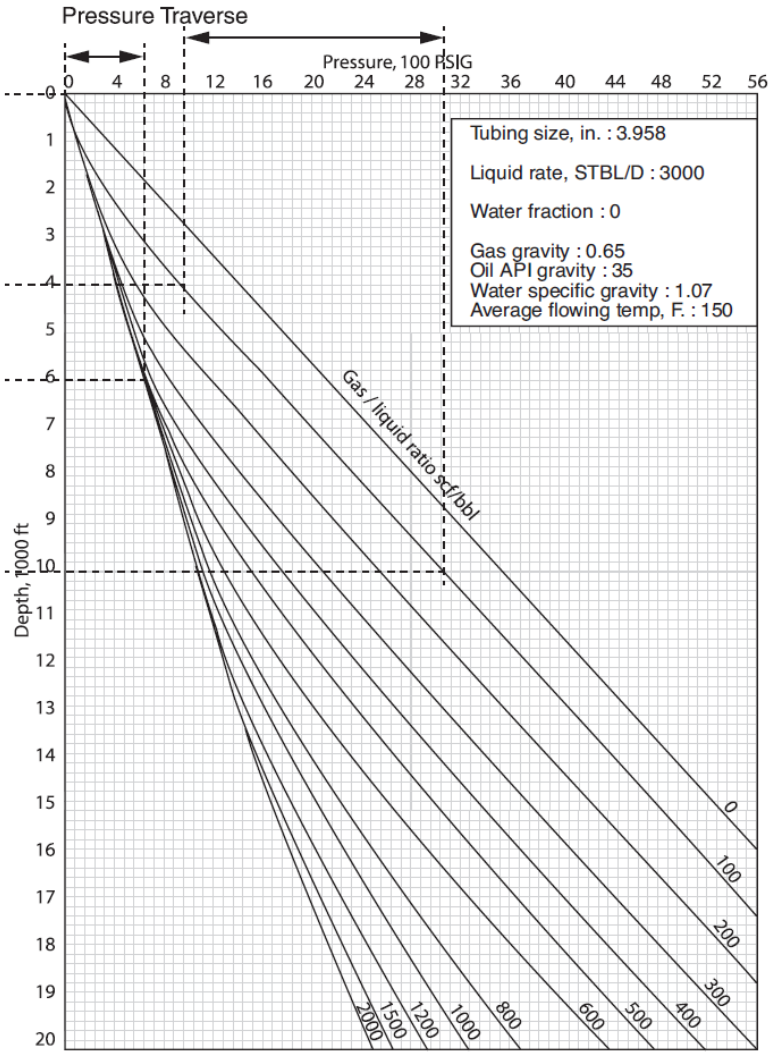
GOR after gas injection = 3,000,000 / 3,000 + 100 = 1,100 SCF/STB

From pressure traverse plot:

- Average flowing gradient **after** lift gas injection:

between 6,000 ft and surface = 600 / 6,000 = 0.1 psi/ft

(6000 ft and surface are arbitrary depths selected to calculate the gradient of the straight line.)



- Average flowing gradient **prior** to lift gas injection

from 10,000 ft to 4,000 ft = (3,040-900)/(10,000-4,000) = 0.357 psi/ft *(4000 ft and 10000 are arbitrary depths selected to calculate the gradient of the straight line.)*

FWP + ΔP above valve + ΔP below valve + Draw down = Reservoir Pressure

Drawdown = Production Rate/PI = 3,000 / 4 = 750 psi

Let depth of valve = x

$$250 + 0.1 * x + (10,000 - x) * 0.357 + 750 = 3,400$$
$$0.1x - 0.357x = 3,400 - 1,000 - 3,570$$
$$x = 1,170 / 0.257$$
$$x = 4,550\ ft$$

Install gas lift valve at 4,550 ft.

iii.

Minimum surface gas injection pressure (P)

P + Gas gradient = Hydrostatic head at 4,550 ft + FWHP

P + (4,550) 0.02 = (4,550) 0.44 + 250

P = 2,252 - 91

P = 2,161 psi

iv.

Required injection gas pressure decreases by the ratio of the brine and dead oil fluid densities.

If dead crude was in the annulus

P1 + 91 = (4,550) 0.368 + 250

P1 = 1,833 psi

. **Solution to Question 4:**

4.A.

Through-tubing guns have small diameter and thus larger clearance, which results in inefficient perforating. This occurs because the perforating gun will always lie against the low side of the hole since wells are never perfectly vertical. This problem is solved for a small diameter gun by having all the perforating charges oriented pointed in the same direction (0° phasing). A magnetic positioning device and/or a swivel sub can be used to orientate the gun so as to ensure there is a minimum clearance between these perforating charges and the casing wall.

4.B.

Drilling and Completion Fluids

- Solid block pore throats => mud solids invasion leading to blocked pore throats => reduce permeability
- Solids have many sources => drilling mud components, drilled formation particles etc.
- Fluid loss increases liquid saturation
- Incompatible formation and fluid loss reduces invaded zone permeability
- Mud filtrate invasion => clay swelling => reduced permeability
- Water block => from increasing water saturation near wellbore due to loss of drilling / completion fluid

Production Operations:

- Scale => due to temperature and pressure changes. Salts in formation water become over saturated and precipitate e.g. calcium carbonate.
- Wax
- Asphaltenes => Asphaltene precipitation due to pressure drop.
- Fines migration
- Sand production due to increased effective stress

Matrix treatment fluid should dissolve (or at least mobilise) the source of

the formation damage, e.g.

wax	-	hot, organic fluids
calcium carbonate scale	-	hydrochloric acid
clay particles	-	mud acid

4.C.

$$S = \left(\frac{k}{k_d} - 1\right)\ln\left(\frac{r_d}{r_w}\right)$$

$r_w = 0.328$, $rD = 1.328 \ln r_d / r_w = 1.40$

$$\frac{J_i}{J_o} = \frac{\ln r_e / r_w}{\ln r_e / r_w + S}$$

$r_w = 0.328$, $r_e = 745$ $\ln r_e / r_w = 7.73$

$$\frac{J_i}{J_o} = \frac{7.73}{7.73 + S}$$

Damage removal

k/k_d	S	J_o/J_i	J_i/J_o
20	26.6	4.44	0.23
4	4.2	1.54	0.65
2	1.4	1.18	0.85
1	0	1.00	1.00

Stimulation

k/k_d	S	J_o/J_i	J_i/J_o
0.5	-0.70	0.91	1.10
0.1	-1.29	0.84	1.20

The above tables reflect the statement "Formation damage reduces well productivity greatly while the stimulation effect of increasing the near wellbore permeability above the initial value has limited effect."

4.D.

Matrix acidizing aims to increase the Productivity Index (PI) by reducing

the Skin (S) through dissolving formation damage components and rock in the near wellbore region. It is particularly suitable for medium/high perm reservoirs with high skin.

Fracturing increases PI by increasing effective wellbore radius through the creation of high conductivity fractures from wellbore. Fractures bypass the damaged zone and extend to a greater depth into the reservoir than can be reached by acidizing. It is suitable for low permeability reservoirs with or without skin.

. **Solution to Question 5:**

5.A.

(i)

Treatment A:

Fracture length (both wings) = $\frac{\text{Proppant}}{\text{loading} * \text{frac. height}}$ = 300,000 / (4*100) = 750 ft

Fracture half length (Xf) = 375 ft

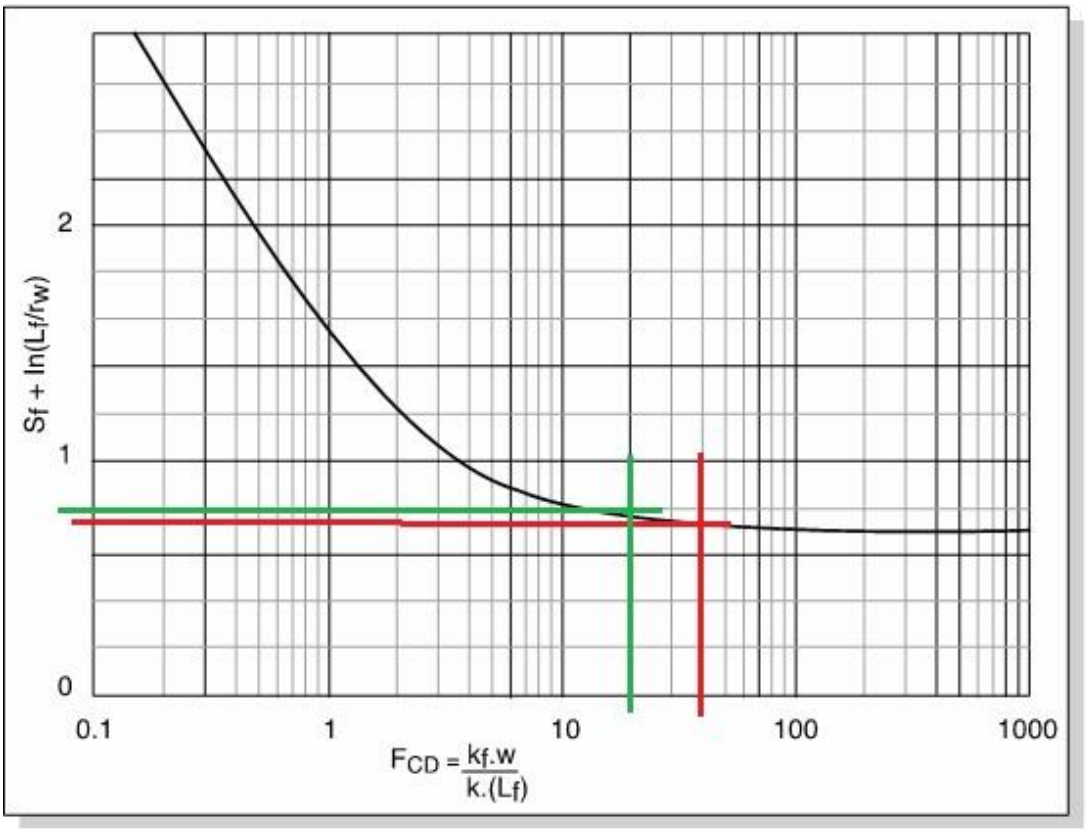
F_{CD} = Kf*w/k*Xf = 1,500 / (0.1*375) = 40

From graph

$\ln (Xf/r_w) + Sf = 0.75$

Sf = 0.75 - ln (375/0.328)

Sf = - 6.29



Treatment B:

Fracture half length = 300,000 / (2*100*2) = 750 ft

FCD = 850/(0.1*750) = 11.3

From graph

Sf = 0.8 - ln (750/0.328) = - 6.93

Treatment B achieves a more negative skin and is recommended.

(ii)

Long fractures are more effective at stimulating low permeability wells providing the fracture conductivity is sufficient (FCD > 10 - 15)

5.B.

Water production causes:

- Higher drawdowns (and thus increased rock stress) and high liquid rates (and thus higher drag forces) to keep the target oil production rate due to relative permeability effects.
- Loss of capillary pressure between the sand grains which helps prevent mobilisation of the sand grains when dry oil is being produced by the well.
- Increased water saturation can reduce the strength of some water-sensitive clay cementing the formation.

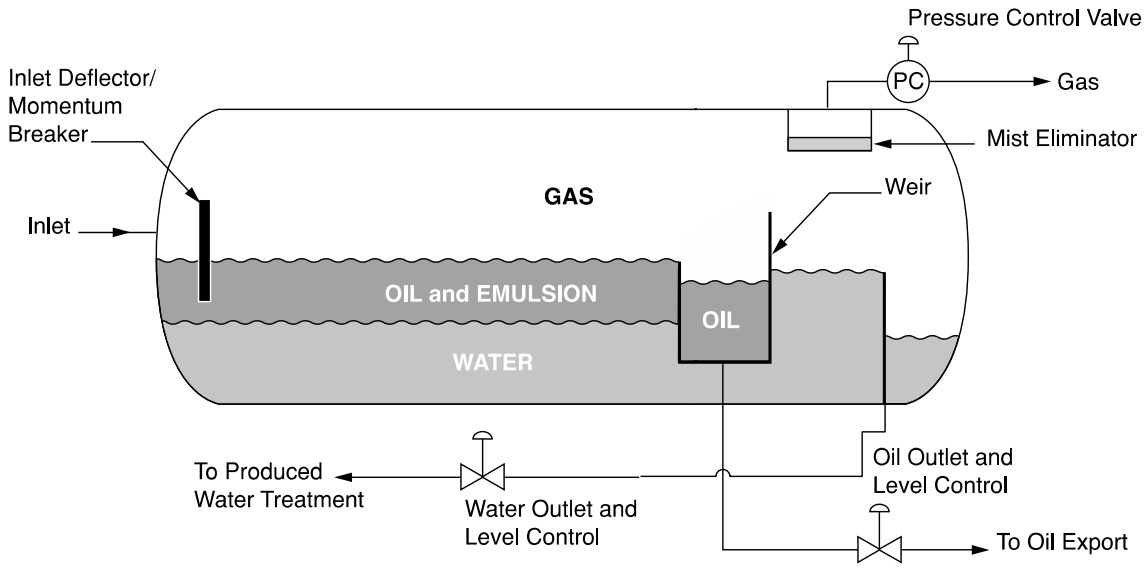
All this may trigger sand production.

5.C.

(i)

Sketch the main components of a 3-phase (gas/oil/water) horizontal separator and briefly (one sentence) explain the function of each of the main components.

(Standard) 3-phase horizontal separator diagram.



Main components	**Main function**
Inlet momentum breaker =>	to reduce inlet flow velocity (hence helping disengage free gas)
Mist eliminator/extractor =>	to remove liquid drops from gas (by allowing liquid droplets to impinge on the wire, coalesce and flow down in to the liquid phase)
Weir =>	to separate oil and water phases (oil is collected here and skimmed off from main settling area)
Liquid outlets under level controls =>	to evacuate oil and water (usually equipped with a vortex breaker to prevent re-entrainment of gas)

(ii)

In a gravity type separator => the separation process takes place due to the action of gravity combined with the difference in densities of the phases/components of the produced fluid.

For a 3-phase separator (vertical/horizontal) the heavier fluids (water and oil) go to the bottom of the vessel while the lighter phase (gas) rises to the top. Therefore:

* Water outlet is located at the bottom of the vessel, remote from the inlet to allow maximum residence time. It is controlled by the oil/water interface level control.

* Oil outlet is also located at the bottom, remote from the inlet to allow maximum residence time. It is connected to the oil level control.

* Gas will flash off and disengage from the liquid phases and exit

from the uppermost part of the vessel remote from the inlet (to allow maximum residence time). Gas outlet is regulated by a pressure control valve which controls the separator operating pressure.

5.D.

(i)

Assume droplet size distribution the same for subsiduary and main production zones.

$$\frac{V_1}{V_2} = \frac{(\rho_{d1} - \rho_{c1})}{(\rho_{d2} - \rho_{c2})} \cdot \frac{\mu_{c2}}{\mu_{c1}}$$

75% water cut

• Water is the continuous phase

• Oil is the discontinuous phase => i.e. oil droplets are separating from the water phase.

$$\frac{V_{main}}{V_{subsiduary}} = \frac{(\rho_{om} - \rho_{wm})}{(\rho_{os} - \rho_{ws})} \cdot \frac{\mu_{ws}}{\mu_{wm}}$$

$$= \frac{(0.85 - 1.1)}{(0.95 - 0.99)} \cdot \frac{0.7}{0.9} = \frac{0.25 \times 0.7}{0.04 \times 0.9} = 4.9$$

Separation of oil droplets from the water phase takes 5 times longer for the more viscous oil. Under these conditions, an increase of residence time of at least 5 times is required in order to achieve the same efficiency of separation.

Since well production is reduced by factor 10, residence time is increased by factor 10 (i.e. 10 times). Therefore separator capacity is sufficient and does not need upgrading.

1% water cut

• Oil is the continuous phase

• Water is the discontinuous phase => i.e. water droplets are separating from the oil phase.

$$\frac{V_{main}}{V_{subsiduary}} = \frac{(\rho_{wm} - \rho_{om})}{(\rho_{ws} - \rho_{os})} \cdot \frac{\mu_{os}}{\mu_{om}}$$

$$= \frac{(1.1 - 0.85)}{(0.99 - 0.95)} \cdot \frac{4.0}{2.5} = \frac{0.25 \times 40}{0.04 \times 2.5} = 100$$

Separation of water droplets from the oil phase takes 100 times longer, i.e would require an increase of residence time of at least 100 times to carry on with the separation process

Despite production rate being reduced by factor 10, separation capacity is still factor 10 too small. Therefore separation capacity is insufficient and needs upgrading.

(ii)

Possible remedial measures are:

• Installation of a coalescer pack to reduce the distance oil and water droplets have to separate

• Add demulsifier chemicals to speed up the rate of droplet aggregation by coalescing the small oil particles to form larger particles which will separate faster (Stokes law - the D term is squared & so the improvement is squared).

END OF SOLUTIONS