Springer Environmental Science and Engineering

Davorin Matanović
Marin Čikeš
Bojan Moslavac

Sand Control in Well Construction and Operation

Springer

Sand Control in Well Construction and Operation

Springer Environmental Science and Engineering

For further volumes:
http://www.springer.com/series/10177

Davorin Matanović • Marin Čikeš •
Bojan Moslavac

Sand Control in Well Construction and Operation

Springer

Davorin Matanović
University of Zagreb
Faculty of Mining, Geology and Petroleum Engineering
Petroleum Engineering Department
Zagreb
Croatia

Marin Čikeš
University of Zagreb
Faculty of Mining, Geology and Petroleum Engineering
Petroleum Engineering Department
Zagreb
Croatia

Bojan Moslavac
University of Zagreb
Faculty of Mining, Geology and Petroleum Engineering
Petroleum Engineering Department
Zagreb
Croatia

ISBN 978-3-642-25613-4 e-ISBN 978-3-642-25614-1
DOI 10.1007/978-3-642-25614-1
Springer Heidelberg Dordrecht London New York

Library of Congress Control Number: 2012930824

Printed on acid-free paper

Springer is part of Springer Science+Business Media (www.springer.com)

Contents

Chapter 1
Introduction

Contents

Abstract The origin, nature and consequences of sand production should be thoroughly examined and evaluated. They have great impact on the nature of the production system if they are produced. Surface gathering system, separating system equipment and some kind of surface safe disposal should be considered too, because of cleaning and disposal expenses.

Also the stability of the formation is changed due the lost of bearing solid material. The problem can be solved using a combination of geomechanical evaluation, optimization of well parameters, oriented and selective perforation, and production optimization by controlling drawdown through the wellbore life cycle.

Starting with the production of oil and gas is always followed by some extent of the solid particles production. The problem occurs throughout the world regardless the age of the reservoirs, but is more often in wells producing from the younger ones (Miocene and Pliocene age sands). That is because these formations are weakly consolidated and the cementing material is often clayey. The possible sand production depends on the interaction of the grains, their inter-granular friction and in-situ stresses, capillary forces and in some cases by the viscosity of the fluids in place. Regardless the opinion that the older, more deeply buried formations are more consolidated it has be found very deep older formations to be completely unconsolidated. It can vary from few to several thousands grams in cubic meter of produced fluid. In some cases (when dealing with heavy oil) it can be useful and is more often applied in last decade. But in other situations it can be a problem that leads to severe and serious accidents if not treated. Main problem is in the fact that any kind of control that is applied includes additional costs and reduction of production.

D. Matanović et al., *Sand Control in Well Construction and Operation*,
Springer Environmental Science and Engineering,
DOI 10.1007/978-3-642-25614-1_1, © Springer-Verlag Berlin Heidelberg 2012

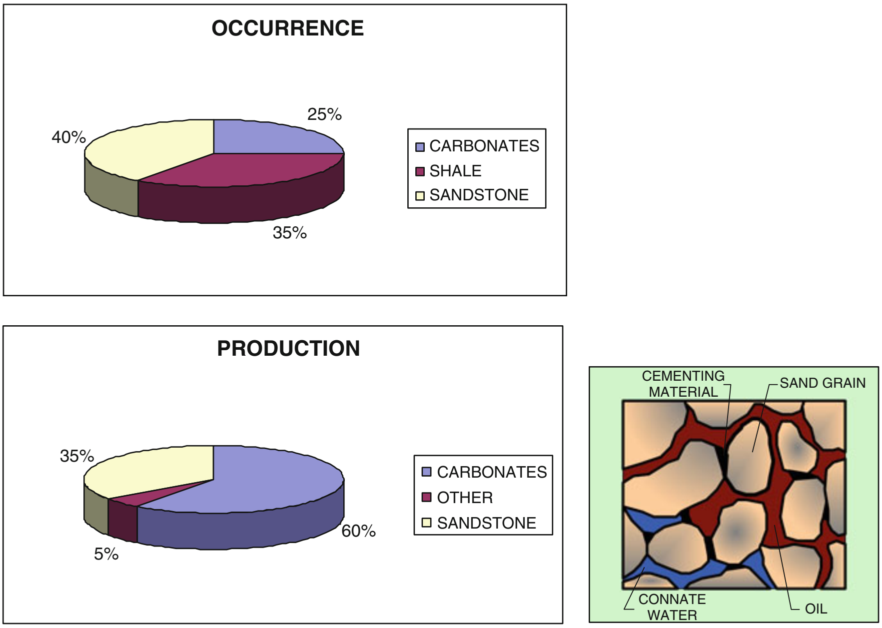


Fig. 1.1 Occurrence and production of oil and gas (Allen and Roberts 1978)

Most oil and gas reservoirs from that time are found in sandstones or carbonates. There are very limited occurrences in shale, volcanic rock, and fractured basement rock (basalt). Comparing the significance of sandstone and carbonate reservoirs, sandstones are more abundant, yet limestones are more important as reservoirs for hydrocarbons (Fig. 1.1).

A Sand Management approach (Tronvoll et al. 2001) that has changed the philosophy of too-conservative approach, is a combination of low-cost solutions and active risk management. To be able to apply the method it is necessary to provide an extensive field data acquisition, secure the theoretical modelling of the physical and chemical processes in the formation, and provide real-time monitoring of production data with well testing to optimize production. The main concern is a risk associated with possible failures. To avoid that, the analysis of sand life cycle must be done. It covers the mechanisms of release and production of rock fragments. Being the hydro-mechanical process it involves the solid particles movement through the formation, perforations, tubing, and surface gathering system. Relevant parameters that must be analyzed at that stage are fluid rheology, density and flow velocity and changes, sand fragment dimensions (size), etc. The result of hard particles flow with the produced fluid is the erosion of completion equipment in contact, thus the extent of steel removing must be determined through erosion risk analysis. Because really different conditions can be experienced optimal time for workovers must be defined to ensure proper safe limit (Peden and Yassin 1986).

Designing of sand control systems and practices in the past have been focused only to such variations in formation conditions and production parameters – that alter through the well life cycle. The produced sand (solids) is oil-contaminated, so due the environmental protection it cannot be thrown away without control. Thus some kind of controlled disposal site or re-injection through injecting wells can be applied.

1.1 Reasons for, Nature and Consequences of Solids Production

The beginning of the sand production is controlled by the amount and type of cementing material that holds individual grains connected together, frictional forces between grains and capillary pressure forces. Sand flowing from unconsolidated formations is always possible. But it is also possible from the formations of high compressive strength with good cementation between grains. In both cases sand production can start immediately or can happen during the wells life time. Stabilization of formation rocks with little or no bonding material can be achieved by allowing forming of stable arches (Stein et al. 1974) over perforation tunnel or screen gaps. Such conditions occur only when the grains are water wet and produced fluids are oil or gas. Forming of natural arches is than supported by capillary forces.

Sand production from high strength formations and good bonding material starts with cleaning the sludge from the perforations. Through the period of production the pore pressure in rock will decrease and there is a possibility of rock crushing due the overburden stress.

The changes in the downhole producing area depend on the amount of cumulative sand volume that has been produced. For better comparison and interpretation on possible events and consequences, the classification of measured sand production was introduced (Veeken et al. 1991). It distinguishes three types of sand production: (1) transient, (2) continuous and (3) catastrophic. First one refers to the declining sand concentrations through the time under constant well production conditions. Second one has been observed in great number of fields. The amount of produced sand that can be considered acceptable depends on operational constraints. That means, regard to erosion, separator capacity, possibilities for sand disposal or transport due the well location, artificial lift system that is used etc. The usual problem is that some amount of produced sand settles inside the wellbore and tubing. Because of that producing interval can be blocked and the necessity for sand washing-up exists. The worst case, catastrophic sand production is the result of high rate sand influx that can collapse production casing or tubing, or fill up parts of the producing system and terminate production.

Regardless the type of sand production it will cause the change in well downhole area geometry (Fig. 1.2). After cleaning the debris from perforations it is possible

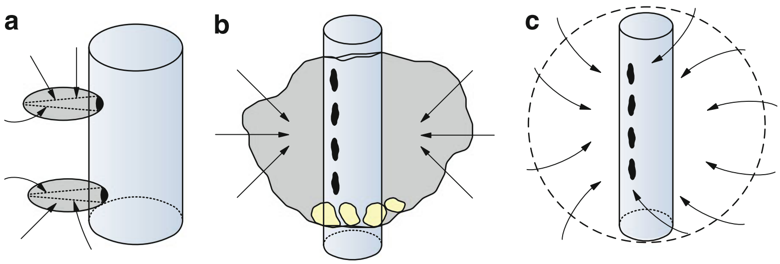


Fig. 1.2 Change in well down hole area geometry due the sand production: (**a**) Perforation enlargement, (**b**) Formation of the large cavity, (**c**) Cavity sloughing

and likely that some extent of perforation enlargement happens (Fig. 1.2a). If such enlargement persists it is possible that to that moment separated perforations merge and a large cavity is formed (Fig. 1.2b). The real measure of the downhole changes is the cumulative volume of sand produced averaged over the perforated interval length. If the formation is unconsolidated or weekly consolidated the sloughing of the sand and even overburden layers in such cavity is probable (Fig. 1.2c).

The best up today example for catastrophic sand production compaction of Wilmington field resulted with surface subsidence of up to 10 m. Several earthquakes have been registered and about 300 producing oil wells have been damaged with complete loss of 120 more (Suman 1974). Usually the compaction of the reservoir increases axial loading and shortening of casing or slotted liner. If loads exceed elastic limit of the steel pipe it can be plastically deformed or slots can be bulged or distorted. The amount of possible formation compaction can be estimated by using Eq. 1.1.

$$\Delta H = \left(\frac{\Delta e}{1 + e_o}\right) H \tag{1.1}$$

Vertical compaction ΔH is determined by the thickness of the zone H, change in void ratio Δe (ratio between the volume of voids and volume of solids) and original void ratio e_o.

The possibility of sand transportation from the well depends of the balance of gravity and hydrodynamics forces. Primary parameters are fluid density and viscosity (rheology), localized velocities, sand fragment size and shape, and well inclination. The flow of the fluid with hard particles (sand grains), and the kinetics energy of the moving particles when in impact with the steel surface, cause abrasive steel removal. Because of that one of the main concerns is to decrease the erosional impact of the sand flow. If not, serious mechanical problems and failures of surface and/or downhole equipment may occur, and that results with some kind of workover. Sand erosion (Fig. 1.3) can occur in both downhole and surface equipment. Downhole erosion is most likely to occur in blast joints, tubing, screens (Fig. 1.3a) or slotted liners that were not adequately packed during the gravel pack completion. Erosion is more severe when the sand is produced in gas or where the produced

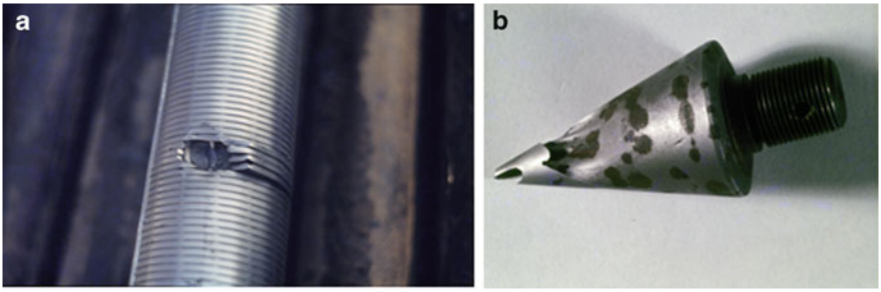


Fig. 1.3 Erosion of the production equipment due the sand production: (**a**) screen erosion, (**b**) surface choke erosion

fluids are in turbulent flow. High-pressure gas containing sand particles and expanding through a surface choke (Fig. 1.3b) is the most hazardous situation, due to the associated high velocity. Excessive erosion at this point could lead to a complete loss of well control.

1.2 Wellbore Stability and Sand Failure Criteria

Wellbore instability is usually caused by a combination of factors which may be broadly classified as being either controllable or uncontrollable (natural) in origin. Uncontrollable factors exist due the natural fractures or faults, tectonic stresses, high in-situ stresses, mobile formations, unconsolidated formations and naturally over-pressured or induced over-pressured shale collapse. Controllable factors are bottomhole pressure (servicing fluid density), well inclination and azimuth, transient pore pressure, physical/chemical rock to fluid interaction, erosion and temperature (McLellan 1994; Bowes and Procter 1997; Chen et al. 1998; Mohiuddin et al. 2001).

Before describing the variety of predictive models that are available for assessing wellbore stability it is necessary to define what constitutes the "failure" of a wellbore. Clearly, the spalling or erosion of manageable amounts of rock from a wellbore wall does not necessarily imply that the wellbore has failed. Providing that sufficient hydraulic power is available to circulate cavings out of the hole it cannot be claimed that hole enlargement, or convergence in many cases, has impaired the ability of the hole to serve its engineering function that is – to gain access to subsurface hydrocarbons. It follows, therefore, that wall deformation and yielding phenomena do not necessarily mean that a wellbore has "failed."

Prior a wellbore is drilled the rock is in a state of equilibrium. The stresses in the earth under these conditions are known as the far field stresses (σ_v, σ_H, σ_h or in-situ stresses (Gaurina-Međimurec 1994). When the well is drilled, the rock stresses in the vicinity of the wellbore are redistributed as the support originally offered by the drilled out rock is replaced by the hydraulic pressure of the mud. The stresses can

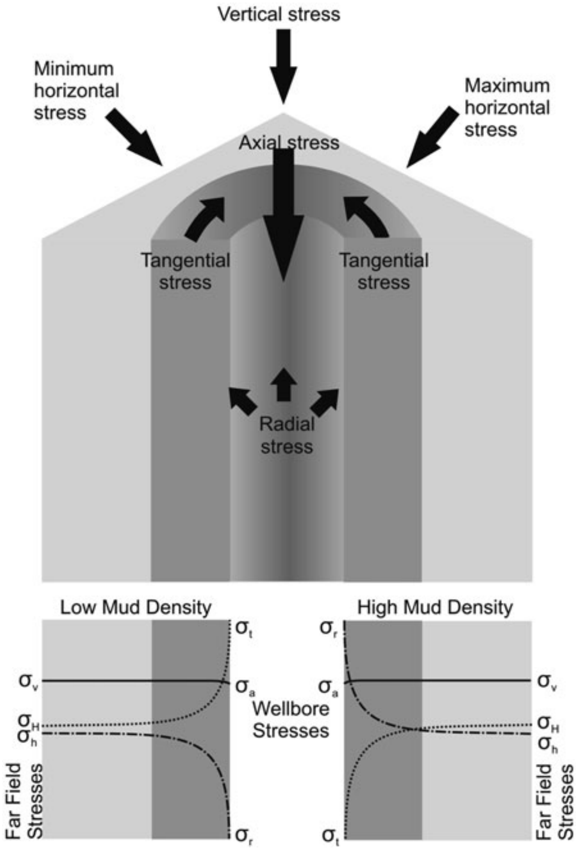


Fig. 1.4 Variation of wellbore stresses away from the wellbore (raltman@slb.com)

be resolved into a vertical or overburden stress, σ_v, and two horizontal stresses, σ_H (the maximum horizontal in-situ stress), and σ_h (the minimum horizontal in-situ stress), which are generally unequal (McLean and Addis 1990).

If the redistributed stress state exceeds the rock strength, either in tension or compression, then instability may result. Figure 1.4 shows the wellbore stresses after drilling. These are described as radial stress σ_r, tangential stress (circumferential or hoop stress) σ_t, and axial stress σ_a. The radial stress acts in all directions perpendicular to the wellbore wall, the tangential stress circles the borehole and the axial stress act parallel to the wellbore axis. It also shows that the wellbore stresses change rapidly with the distance of the borehole, and convert to the far field stresses. That is because away from the borehole the rock is in original and not unperturbed state. So radial stress σ_r changes in to minimum horizontal stress σ_h, and tangential stress σ_t is converging to maximum horizontal stress σ_H.

The local stress distribution around a wellbore is controlled by mechanical (in-situ stresses), chemical, thermal, and hydraulic effects. The coordinate referencing

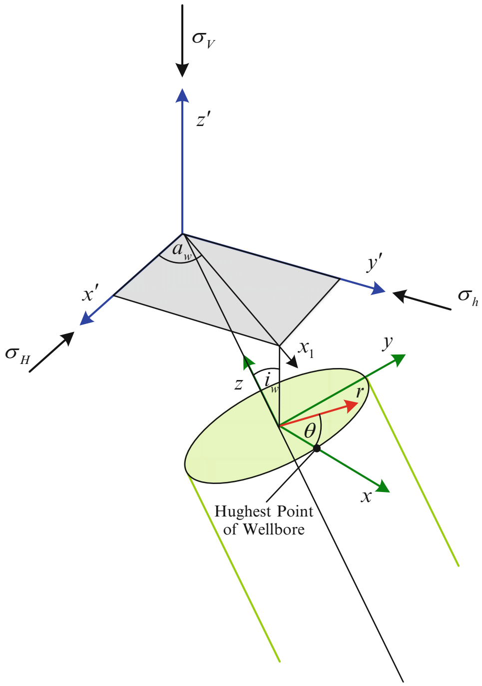


Fig. 1.5 Coordinate system according to well configuration (Pašić et al. 2007)

system used to calculate the stress distribution around a wellbore, governed by the in-situ stresses and hydraulic effects is shown in Fig. 1.5.

Local stresses induced by in-situ stress and hydraulic effects at the wellbore wall ($r = r_w$), for vertical well can be described as follows (Fjær et al. 2008):

$$\sigma_r = p_w \tag{1.2}$$

$$\sigma_t = \left(\sigma_x + \sigma_y\right) - \left(\sigma_x - \sigma_h\right)\cos 2\theta - p_w \tag{1.3}$$

$$\sigma_a = \sigma_z - 2\left(\sigma_x - \sigma_y\right) v \cos 2\theta \tag{1.4}$$

According to previous equations it can be concluded that the radial stress σ_r depends on the wellbore pressure p_w or weight of servicing fluid. The tangential stress σ_t depends on normal stress in (x) direction σ_x, normal stress in (y) direction σ_y, minimum horizontal stress σ_h, the angle between a point on the circumference of the well and the direction of the maximum horizontal stress θ and the wellbore pressure p_w, The axial stress σ_a depends on normal stress in (z) direction σ_z, normal stress in (x) direction σ_x, normal stress in (y) direction σ_y, Poisson's ratio for rock v and the angle between a point on the circumference of the well and the direction of the maximum horizontal stress θ. The wellbore stresses diminish rapidly from the borehole wall converting to far field stresses because away from the wellbore the rock is in an undisturbed state.

Local stresses at the wellbore wall ($r = r_w$) induced by chemical and thermal effects can be expressed as follows:

$$\sigma_r = 0 \tag{1.5}$$

$$\sigma_t = \frac{\alpha_p(1-2v)}{1-v}\left(p_w - p_{pi}\right) + \frac{E\alpha_t}{3(1-v)}(T_w - T_i) \tag{1.6}$$

$$\sigma_a = \frac{\alpha_p(1-2v)}{1-v}\left(p_w - p_{pi}\right) + \frac{E\alpha_t}{3(1-v)}(T_w - T_i) \tag{1.7}$$

It can be noted that Biot's constant α_p, Poisson's ratio for rock v, wellbore pressure p_w, initial pore pressure p_{pi}, Young's modulus E, volumetric-thermal-expansion-constant α_t and temperature profiles (wellbore wall temperature T_w and initial formation temperature T_i) are needed to calculate the stress distribution around a wellbore arising from chemical and thermal effects. The pore pressure profile is altered by water and ion movements into or out of the shale due to hydraulic, chemical, and electrical potentials. Pore pressure and temperature profiles can be obtained by using equations presented in literature (Ottesen and Kwakwa 1991; Lomba et al. 2000; Awal et al. 2001; Zhang et al. 2006; Nguyen et al. 2007).

In order to evaluate the potential for wellbore stability a realistic constitutive model must be used to compute the stresses and/or strains around the wellbore. The computed stresses and strains must then be compared against a given failure criterion.

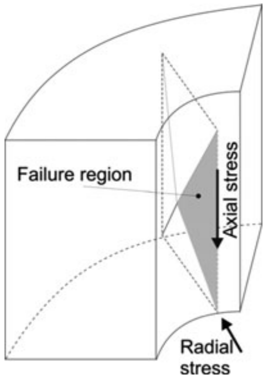
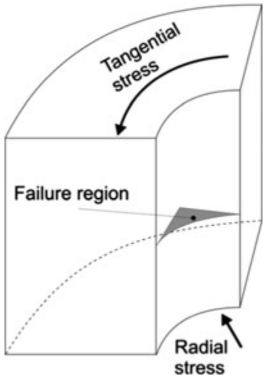
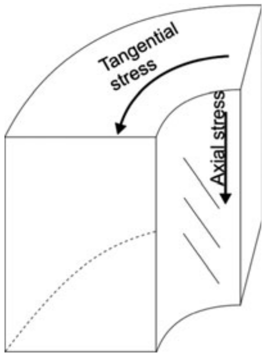
Numerous shear failure criteria (Table 1.1) such as Mohr-Coulomb, Drucker-Prager, von Mises, modified Lade criteria and others are proposed in the literature (Simangunsong et al. 2006; Zhang et al. 2006; Maury and Sauzay 1987; Morita and Ross 1993; McLean and Addis 1990).

The Mohr-Coulomb shear-failure model is one of the most widely used models for evaluating borehole collapse. This model neglects the intermediate principal stress but includes the effect of directional strengths of shales. The shear-failure criterion includes maximum principle stress σ_1, Biot's constant α_p and pore pressure p_p, and makes the relation with the cohesive strength of the rock C_o, minimum principle stress σ_3, and internal friction angle φ. It can be expressed by the following equation:

$$\left(\sigma_1 - \alpha_p p_p\right) \le C_o + \left(\sigma_3 - \alpha_p p_p\right)\tan^2\varphi \tag{1.8}$$

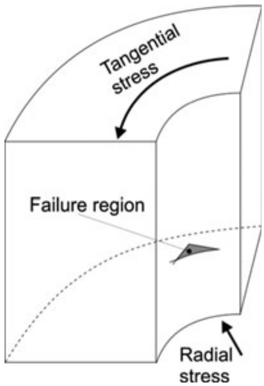
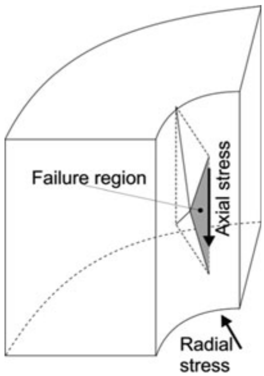
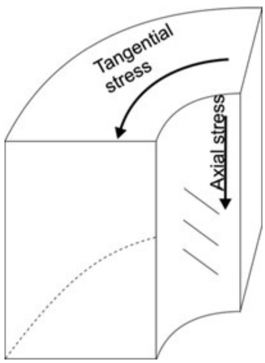
Tensile failure occurs when the stress imposed by drilling mud exceeds the tensile strength of formation (T_o). The extremely excessive weight of drilling mud creates hydraulic fracture, which triggers massive circulation loss and matrix

Table 1.1 Shear failure types

<table>
<tr><th>Failure type</th><th>Geometry and orientation</th><th>Figure</th></tr>
<tr><td>Shear failure shallow knockout
$\sigma_a > \sigma_t > \sigma_r$</td><td>The failure will occur in the radial/axial plane because the maximum (σ_a) and minimum (σ_r) stresses are oriented in this plane (a vertical plane)</td><td>
</td></tr>
<tr><td>Shear failure wide breakout
$\sigma_t > \sigma_a > \sigma_r$</td><td>The failure will occur in the radial/tangential plane because the maximum (σ_t) and minimum (σ_r) stresses are oriented in this plane (the horizontal plane)</td><td>
</td></tr>
<tr><td>Shear failure high-angle echelon
$\sigma_a > \sigma_r > \sigma_t$</td><td>The failure will occur in the axial/tangential arc because the maximum (σ_a) and minimum (σ_t) stresses are oriented in this arc (the arc of the borehole wall)</td><td>
</td></tr>
</table>

(*continued*)

Table 1.1 (continued)

Failure type	Geometry and orientation	Figure
Shear failure narrow breakout $\sigma_r > \sigma_a > \sigma_t$	The failure will occur in the radial/tangential plane because the maximum (σ_r) and minimum (σ_t) stresses are oriented in this plane (the horizontal plane)	
Shear failure deep knockout $\sigma_r > \sigma_t > \sigma_a$	The failure will occur in the radial/axial plane because the maximum (σ_r) and minimum (σ_a) stresses are oriented in this plane (a vertical plane)	
Shear failure low-angle echelon $\sigma_t > \sigma_r > \sigma_a$	The failure will occur in the axial/tangential arc because the maximum (σ_t) and minimum (σ_a) stresses are oriented in this arc (the arc of the borehole wall)	

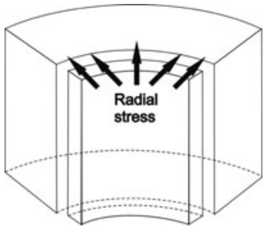
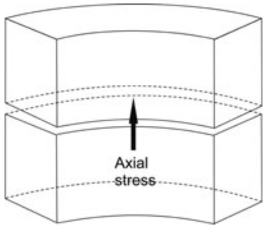
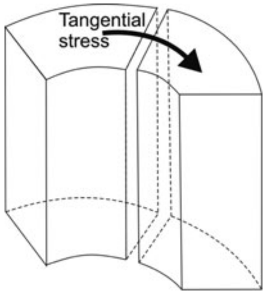
deformation. Hence, this failure becomes the upper limit of the mud density window in safe drilling practice.

Tensile failure usually occurs when the least effective principal stress σ_3 when supported by pore pressure p_p surpasses the formation rock tensile strength T_o. Mathematically this criterion can be expressed as follows in Eq. 1.9 (Simangunsong et al. 2006; Zhang et al. 2006):

$$\sigma_3 - p_p \leq T_o \tag{1.9}$$

The tensile strength of the rock can be assumed to be equal to zero because, theoretically, a fracture initiates in a flaw, a joint, or an existing fracture. To apply the criteria in Eq. 1.9 all principal stresses are subject to tensor transformations. Tensile stress magnitudes can be ordered in three different ways, as shown in Table 1.2 (Bowes and Procter 1997).

Table 1.2 Tensile failure types

Failure type	Geometry and orientation	Figure
Tensile failure cylindrical $\sigma_r \leq -T_o$	This failure is concentric with the borehole. A low mud weight would favour the failure due to the magnitude of σ_r being lower	
Tensile failure horizontal $\sigma_a \leq -T_o$	This failure creates horizontal fractures	
Tensile failure vertical $\sigma_t \leq -T_o$	This failure creates a vertical fracture parallel with the maximum horizontal stress direction. This is because in this orientation tangential stress has to overcome the smallest formation tensile strength	

Sand production from the formation is the result of unconsolidated or disintegrated sand grains around the wellbore or perforations. Usually that are rocks of low or intermediate strength with little or no cementing/bonding material between grains; but in fact sand production is possible also from the higher strength formations with good grain bonding. In both cases sand production can start immediately or can result later in well life cycle.

Fine particles (sand grains) in weakly consolidated formations will start to flow due to stresses caused by fluids flowing into the wellbore that is sufficient to cause fine particles to be agitated. Much more, the particles lodging in pore throats near to the wellbore, redirects the fluid flow pattern and alter the direction and magnitude of the stress fields, which leads to additional particles being dislodged. Once the induced stresses exceed the formation strength, increased sand production will follow.

When formation is producing oil, it is possible that there will be no sand production. But when water begins to flow through the matrix it will raise the drag resistance among the water phase and the water-wetted sand grains and cause the well to start producing sand. Water production always reduces a formation's strength due to the dispersion of amorphous bonding materials. The magnitude of the fluid drag is dependent on velocity (and therefore a function of both permeability and flow rate) as well as fluid viscosity, interfacial tension and fluid phase.

Sand production is possible even from the formation with fair grain bonding and of higher formation strength. It starts with the cleaning of perforations and continues with breaking of the formation due the overburden pressure and lowering of pore pressure along with production.

Because of variety of possible situations it is suitable to consider all procurable options. Exclusion of any kind of sand control is done based on the sand prediction analysis. Operational problems related to sand production vary from expensive sand handling problems to the complete loss of a productive zone or even the possibility of lost well control, due to eroded surface equipment. At the same time produced sand lowers the production rate, and any other kind of installed sand control equipment does the same. But at the same time, removal of the infilling, damaged material clears the pore space and rises the near wellbore rock permeability. That can lead to negative skin values and increase of the productivity index in heavy oil production. The fact is that such approach can lead to low-cost solutions with the need of active risk management. It requires the analysis based on extensive field data acquisition, theoretical modelling of all involved physical processes, currently monitoring of production data with well testing to help in completion design optimization and risk assessment.

The decision of implement or does not implement any kind of sand control can be done based on the integrated geomechanical and passive sand-control approach proposed by Rahman et al. (2010). It presents a general rock-failure criterion as a function of stresses in the formation, rock strength, reservoir pressure and its changes and wellbore trajectory and perforations spacing and direction. The aim is to evaluate possible sanding through approach shown in the workflow in Fig. 1.6.

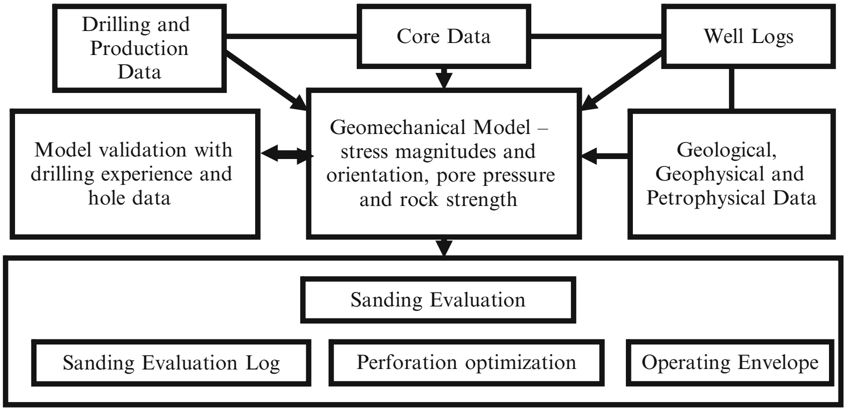


Fig. 1.6 Sanding-evaluation workflow (Rahman et al. 2010)

Good approach through out appropriate sand control can be a combination of geomechanical evaluation (determination of loading factor – *LF*), optimization of well parameters (well trajectory according to maximal stress direction and perforation orientation as well) and production optimization by controlling drawdown through the well life cycle.

According to Wilson et al. (2002), to avoid sand production, the largest effective tangential stress σ_{t2}, for far field total stresses $\sigma_1 > \sigma_2$, with bottomhole pressure p_w, should be smaller than the effective strength of the formation U.

$$\sigma_{t2} - p_w \leq U \tag{1.10}$$

Tangential stresses at the wall of a hole can be solved according to the Fig. 1.7. Tangential stresses on the surface of the hole can be written as:

$$\sigma_{t1} = 3\sigma_2 - \sigma_1 - p_{wf}(1 - A) - Ap_e \tag{1.11}$$

and

$$\sigma_{t2} = 3\sigma_1 - \sigma_2 - p_{wf}(1 - A) - Ap_e \tag{1.12}$$

They give the relations among tangential stresses on the surface of the hole $\sigma_{t1,2}$, bottomhole flowing pressure p_{wf}, reservoir pressure (far field) p_e, and poro-elastic constant A (defined in Eq. 1.13).

$$A = \frac{(1 - 2 \cdot v)\alpha_p}{1 - v} \tag{1.13}$$

Where α_p represents Biot's constant defined in Eq. 1.14, with c_r representing bulk rock compressibility, and c_b representing grain compressibility.

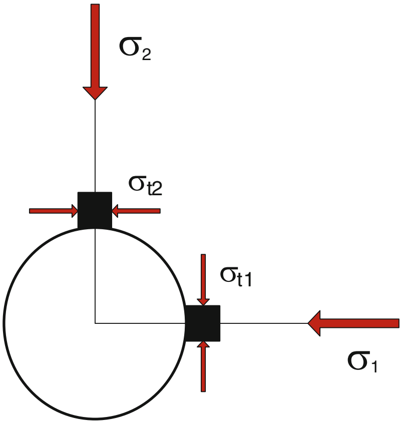


Fig. 1.7 Tangential stresses at the wall of a hole (Wilson et al. 2002)

$$\alpha_p = 1 - \frac{c_r}{c_b} \tag{1.14}$$

The critical bottom-hole flowing pressure (*CBHFP*) that will result with sand production is than:

$$p_{wf} \geq CBHFP = \frac{3\sigma_{t1} - \sigma_{t2} - U}{2 - A} - p_e \frac{A}{2 - A} \tag{1.15}$$

Because the sand production is the function or result of the drawdown from the reservoir pressure, and the bottomhole pressure in the well equals ($p_{wf} = p_e - CDP$); (*CDP* is critical drawdown pressure to cause failure), it is possible to find relation between the reservoir pressure p_e and *CDP*:

$$p_e = \frac{1}{2}[3\sigma_{t1} - \sigma_{t2} - U + CDP(2 - A)] \tag{1.16}$$

or,

$$CDP = \frac{1}{2 - A}[2p_e - (3\sigma_{t1} - \sigma_{t2} - U)] \tag{1.17}$$

Effective strength of the formation *U* can be determined in several ways, but the most often is so-called thick-wall cylinder test (collapse pressure of the standard specimen TWC_{sp}). Different sizes of specimens are used for laboratory testing (one possible is 31.8 mm [1.5 in.] outer diameter *OD*, 12.7 mm [0.5 in.] inner diameter *ID* and 76.2 mm [3 in.] long). Because the formation to well *OD*/*ID* ratio tends to infinity, the accepted relation is:

$$U = 2 \cdot 1.55TWC_{sp} = 3.1TWC_{sp} \tag{1.18}$$

The term loading factor (LF) has been included:

$$LF = \frac{\sigma_{t2} - p_{wf}}{U} \geq 1 \tag{1.19}$$

That means that for $LF < 1$ the formation will not fail, but for $LF > 1$ the formation is failed and sand is produced.

Nomenclature

A	Poro-elastic constant (Eq. 1.13), dimensionless
a_w	Well azimuth, degrees
C_o	Cohesive strength of the rock, Pa
c_r	Bulk rock compressibility, Pa^{-1}
c_b	Grain compressibility, Pa^{-1}
$CBHFP$	Critical bottomhole flowing pressure, Pa
CDP	Critical drawdown pressure to cause failure, Pa
E	Young's modulus, Pa
e_o	Original void ratio, dimensionless
H	Thickness of the zone, m
i_w	Well inclination, degrees
LF	Loading factor (Eq. 1.19), dimensionless
p_e	Reservoir pressure (far field), Pa
p_i	Initial pore pressure, Pa
p_p	Pore pressure, Pa
p_{pi}	Initial pore pressure, Pa
p_w	Wellbore pressure, Pa
p_{wf}	Bottomhole flowing pressure, Pa
r	Near wellbore position, m
r_w	Wellbore radius, m
T_i	Initial formation temperature, K
T_o	Tensile strength of formation rock, Pa
T_w	Wellbore wall temperature, K
TWC_{sp}	Collapse pressure of the standard specimen, Pa
U	Effective strength of the formation, Pa
α_p	Biot's constant, dimensionless
α_t	Volumetric-thermal-expansion-constant, K^{-1}
ΔH	Vertical compaction, m
Δe	Change in void ratio, dimensionless
θ	Point location angle, degrees
φ	Internal friction angle, degrees
v	Poisson ration, dimensionless
σ_1	Maximum principal stress, Pa

σ_2	Medium principal stress, Pa
σ_3	Minimum principal stress, Pa
σ_a	Axial stress at wellbore, Pa
σ_h	Minimum in-situ horizontal stress, Pa
σ_H	Maximum in-situ horizontal stress, Pa
σ_r	Radial stress at wellbore, Pa
σ_t	Tangential stress at wellbore, Pa
$\sigma_{t1,2}$	Tangential stresses on the surface of the hole, Pa
σ_{t2}	The largest effective tangential stress, Pa
σ_v	Vertical or overburden stress, Pa
σ_x	Normal stress in x-direction, Pa
σ_y	Normal stress in y-direction, Pa
σ_z	Normal stress in z-direction, Pa

References

Allen TO, Roberts AP (1978) In: Production operations, vol 1: Well completions, workover and stimulation, Chapter 1. Oil & Gas Consultants International, Tulsa

Awal MR, Khan MS, Mohiuddin MA, Abdulfaheem A, Azeemuddin M (2001) A new approach to borehole trajectory optimization for increased hole stability. In: Paper SPE 68092, SPE Middle East oil show, Bahrain, 17–20 Mar 2001

Bowes C, Procter R (1997) Drillers stuck pipe handbook, 1997 guidelines & drillers handbook credits. Schlumberger, Ballater

Chen X, Tan CP, Haberfield CM (1998) A comprehensive practical approach for wellbore instability management. In: Paper SPE 48898 presented at the 1998 SPE international conference and exhibition in China, Beijing, 2–6 Nov 1998

Fjær E, Holt RM, Horsrud P, Raaen AM, Risnes R (2008) Petroleum related rock mechanics, 2nd edn. Elsevier, Amsterdam

Gaurina-Međimurec N (1994) Mechanical factors of wellbore instability. Nafta 45(3), Zagreb

Lomba RTF, Chenevert ME, Sharma MM (2000) The role of osmotic effects in fluid flow through shales. J Pet Science Eng 25:23–25

Maury VM, Sauzay JM (1987) Borehole instability: case histories, rock mechanics approach and results. In: Paper SPE/IADC 16051, SPE/IADC drilling conference, New Orleans, 15–18 Mar 1987

McLean MR, Addis MA (1990) Wellbore stability analysis: a review of current methods of analysis and their field application. In: Paper IADC/SPE 19941 presented at the 1990 IADC/SPE drilling conference, Houston, 27 Feb–2 Mar 1990

McLellan P (1994) Assessing the risk of wellbore instability in horizontal and inclined wells. In: Paper HWC94-14 presented at the Canadian SPE/CIM/CANMET international conference on recent advances in horizontal well applications, Calgary, 20–23 Mar 1994

Mohiuddin MA, Awal MR, Abdulraheem A, Khan K (2001) A new diagnostic approach to identify the causes of borehole instability problems in an offshore Arabian field. In: Paper SPE 68095 presented at the 2001 SPE middle east oil show, Bahrain, 17–20 Mar 2001

Morita N, Ross CK (1993) Core-based horizontal or highly inclined well stability analysis for unconsolidated formations. In: Paper SPE 26332 presented at the 68th annual technical conference and exhibition of the society of petroleum engineers, Houston, 3–6 Oct 1993

Ottesen S, Kwakwa KA (1991) A multidisciplinary approach to in-situ stress determination and its application to wellbore stability analysis. In: Paper SPE/IADC 21915, SPE/IADC drilling conference, Amsterdam, 11–14 Mar 1991

Pašić B, Gaurina-Međimurec N, Matanović D (2007) Wellbore instability: causes and consequences. Min Geol Pet Eng Bull 19:87–98

Pedden JM, Yassin AAM (1986) The determination of optimum completion and production conditions for sand-free oil production. In: SPE 15406. 61st annual technical conference and exhibition, New Orleans, Vol. 25, No. 2, 5–6 Oct 1986

Rahman K, Khaksar A, Kayes T (2010) An integrated geomechanical and passive sand-control approach to minimize sanding risk from openhole and cased-and-perforated wells. SPE Drill Completion, June 2010, 26(10):155–167

raltman@slb.com (-) Rock Mechanics Self Learning Package, Sugar Land Learning Centre

Simangunsong RA, Villatoro JJ, Davis AK (2006) Wellbore stability assessment for highly inclined wells using limited rock-mechanics data. In: Paper SPE 99644 presented at the 2006 SPE annual technical conference and exhibition, San Antonio, 24–27 Sept 2006

Stein N, Odeh AS, Jones LG (1974) Estimating maximum sand-free production rates from friable sands for different well completion geometries. J Pet Technol, October 1974, 26(10):1156–1158

Suman GO Jr (1974) Sand control, Part 1, World Oil, Nov 1974, Vol. 26, No. 10

Tronvoll J, Dusseault F, Santarelli FJ (2001) SPE 71673 the tools of sand management. In: SPE annual technical conference and exhibition, New Orleans, 30 Sept–3 Oct 2001

Veeken CAM, Davies DR, Kenter CJ, Koojima AP (1991) Sand production prediction review: developing an integrated approach. In: SPE 22792. 66th annual technical conference and exhibition, Dallas, 6–9 Oct 1991

Wilson SM, Moschovidis ZA, Cameron JR, Palmer ID (2002) New Model for Predicting the Rate of Sand Production. In paper SPE/ISRM 78168. Rock mechanics conference, Irving, 20–23 Oct

Zhang J, Yu M, Al-Bazali TM, Ong S, Chenevert ME, Sharma MM, Clarc DE (2006) Maintaining the stability of deviated and horizontal wells: effects of mechanical, chemical, and thermal phenomena on well designs. In: Paper SPE 100202, presented at the 2006 SPE international oil & gas conference and exhibition in China in Beijing, China, 5–7 Dec 2006

Chapter 2
Formation Sampling and Sand Analysis

Contents

Abstract The starting point for any kind of sand control with respect to geomechanical approach is proper sampling and sand screen analysis. Use of bailed or produced sand samples leads to mistakes and problems and is the poorest kind of data that can be used in designing sand control. The representative samples are obtained by coring the whole length of the interval with adequate coring equipment. Particle size distribution is then determined through sieve and laser particle size (LPS) analysis.

LPS is used to determine the amount of fine particles that exist due the swelling and migration of bonding clays, or due the crushing during production.

Such analysis is the basis for proper design of liner openings, screens or gravel pack sizing.

When analyzing gravel-pack effectiveness it can be stated that most of such completions are only partially effective. One of the factors that mostly contribute is the use of improper gravel size. The analysis should be done on the representative samples from the reservoir. Due the changes in porosity and permeability (heterogeneity) of the formation it is possible that core samples will vary a lot within the interval. The best samples of formation rocks are obtained by continuous coring with adequate equipment and proper control according to core measuring and spacing.

Because of an expense that is not likely in all situations, so only the interesting parts of the reservoir would be cored continuously. The work that has showed the best the problem of representative formation sampling (Maly and Krueger 1971) states that there is no simple, clear answer to the best sampling procedure. It will depend upon possible level of investment, quality of core recovery, desired well production, quality of available screen or gravel etc. Because of formation horizontal and vertical heterogeneity it is not enough to provide random coring in

D. Matanović et al., *Sand Control in Well Construction and Operation*,
Springer Environmental Science and Engineering,
DOI 10.1007/978-3-642-25614-1_2, © Springer-Verlag Berlin Heidelberg 2012

non-uniform sands. In such situations even coring of closely spaced intervals does not give good enough information. It is strongly recommended to core the entire interval and analyze samples from regular distances (0.3048 m). Whenever that is not possible high quality gravel of very small size (0.297 mm i.e. 60 mesh) is recommended, but also clean fluids and well designed screens should be used to. When formations are proved to be uniform it is possible to use wider spaced samples (1.5, 3.0 or 6.0 m). Formation sands can be: quick sands (that means completely unconsolidated sands), partially or weakly consolidated sands (with some cementing materials present) and friable sands (with good cement bonding but with potential to be produced). Depending on mentioned consolidation the use of double-tube core barrels or those with rubber sleeve is strongly recommended. Using such equipment will enable to get full volume of formation cored. Such coring equipment is shown in Fig. 2.1.

When such samples are not sufficient or have not been obtained it is possible to use side coring equipment. They are less expensive and can be used even in workover operations. The main disadvantage is in the sample dimensions because they are small. Sometimes several side core samples are combined but that can also mislead and give wrong data for further analysis. Combined samples can be used only to confirm that a sand production exists.

Screen analysis of bailed or produced materials is the poorest kind of data to be used in designing sand control. That is because bailed or produced material will not contain all size ranges of formation material. Due to flow velocity and the carrying capacity of produced fluid, different particle sizes should be separated and settled in the well or somewhere else in the production or separation system. The difference in obtained samples is visible when the so called “log probability” plot is drawn. The benefit of the method is that sampling and testing errors can be detected on the plot because the anomalies are easily visible, as shown in Fig. 2.2.

The representative formation samples are plot as the straight line. Those points that deviate from the straight line could indicate a mistake in sampling, sieve analysis or in data recording. In fact produced samples will have a large amount of fine particles, because the coarser material will remain in the rathole, and the plot will have a rise on the right side and the flatter slope. As the opposite, bailed samples will have coarse particles; the plot will tend to the left side, with a stepper slope.

2.1 Sieve Analysis

Routinely performed core analysis that are done in laboratories, are given in *API Recommended Practices 58* (API 1995). Their results are used to help design the best sand control method. Because the clays and silts are also in many cases combined with sands there is a need for spectrographic analysis to determine the amount and the type of clays or silts within the formation. That is especially important when selecting the servicing or carrying fluid and additives included

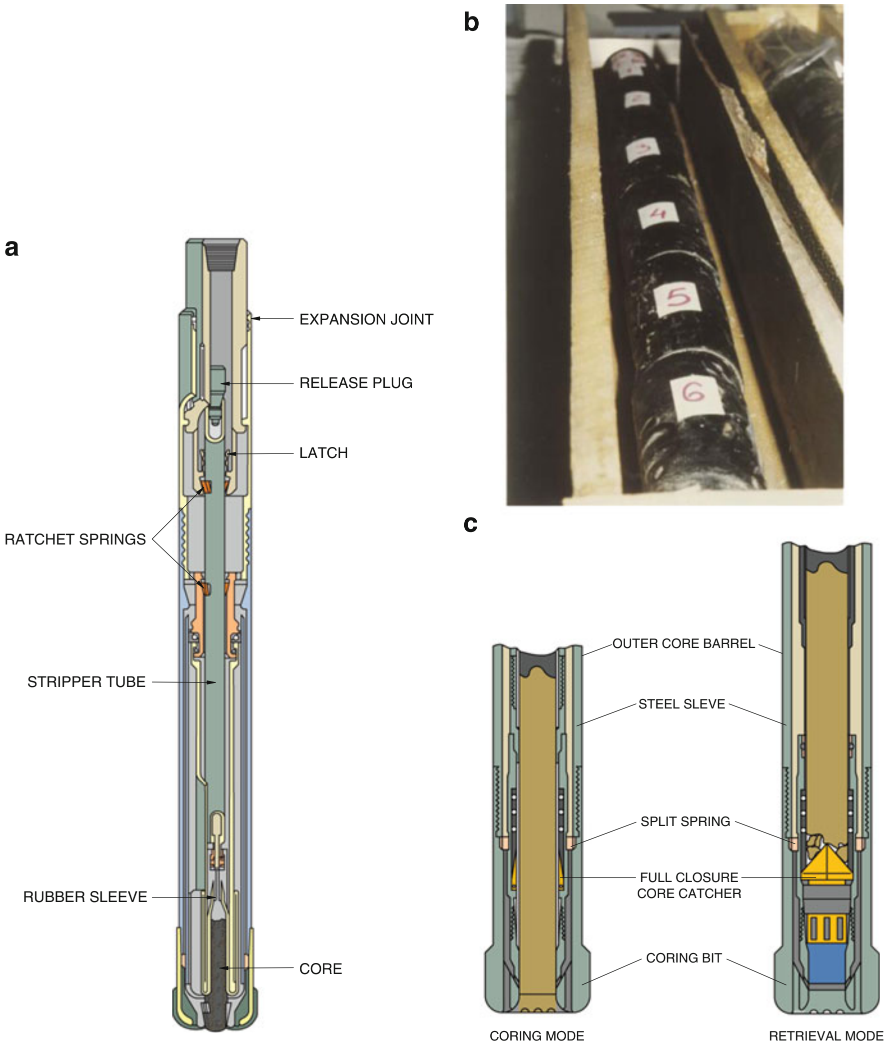


Fig. 2.1 Rubber sleeve core barrel (**a**), rubber or plastic sleeve core sample (**b**), full close core barrel (**c**) (Baker Hughes Inteq 1999)

with the treatment. The main postulate is to remain core intact during storage, transportation and testing. Also the permeability studies are recommended to determine the rock sensitivity to water encroachment (formation or fresh injected water). But the most important part is the determination of the size of particles, because they have to be contained with applied treatment method.

Being the most common cementing (binding) material in young deltaic formations clays and silts have considerable role in the efficiency of selected sand control method. With more than 15% clay or silt content, there are always problems in sand

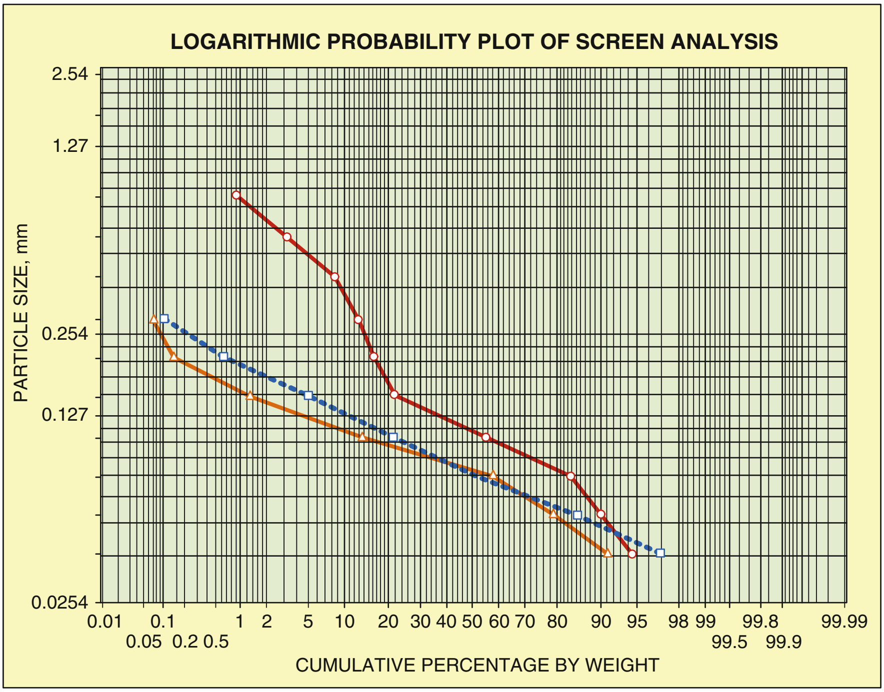


Fig. 2.2 Logarithmic probability plot of screen analysis (Dowel-Schlumberger 1979)

control application. The main problem is in selection of compatible completion and treatment fluid. Also due the small particle sizes, the controlling element (screen or liner slots, gravel size or high-resin-content plastics) impairs in decrease of permeability what leads to decrease in production. The problem with clays can be due the swelling or migration. Montmorillonite can swell six to ten times its original volume when in contact with fresh water (or the completion fluid with a considerably lower salinity of the fluid in formation). Because of that the use of brines is recommended to stabilize clays. Also oil-based servicing fluids can be used because in water-wet formation they will not cause clay migration. Kaolinite and ilite will disperse and fill or bridge the pore throat. This mechanical instability is present when wetting phase is mobile and its velocity exceeds the critical velocity that will cause particle movement. Dispersion test is simple method for determination of type and amount of clays and silts in sample. The sample is mixed with water and dispersant, and than left to stand for 1 h. The sand and silt particles will settle and the clay particles will be suspended in water. The clay content is than determined by comparing dispersion clarity with known standards. Other possible methods are: the hydrometer analysis method, solubility determination, spectrographic examination and use of scanning electron microscope (SEM) as well.

Reliable method to separate clays and silts from sand grains is the wet analysis. Through the procedure, a sample of known weight is mixed with water containing dispersant. Using the rubber pestle the sample is disintegrated without crushing the sand grains. All material is than washed through a 44 μm sieve where the silt and clay particles are separated. The dispersion is then dehydrated, weighted and recorded showing the silt and clay content. The rest of material is sieved using conventional sieving method, sieve cuts weighed and plotted. The dispersed silt and clay dried and sieved too. The sieve analysis is done according the data obtained by sieving through the different amount of screens depending on the commercial testing laboratory. It can vary from 15 to 25 different sieve openings. Measures that can or are usually used in screen analysis are shown in Fig. 2.3. Sand, silt and clay size ranges are shown and related to the Tyler standard series and Phi scale.

The *Phi* scale is calculated from the equation:

$$Phi = -\log_2 d \tag{2.1}$$

Where d is the grain diameter in millimeters.

Tyler and U.S. Standard screen numbers and corresponding sieve openings are listed in Table 2.1.

The disaggregated and dry sample is weighted and passed through a series of sieves mounted one over another. Usually with maximal diameter on the top and with minimum diameter of 44 or 38 μm on the bottom are used. The material on each sieve is weighed. To determine certain point on the cumulative grain size the percentage retained on the individual screens, starting with that with the larger openings are added together until the total equals determined percentage

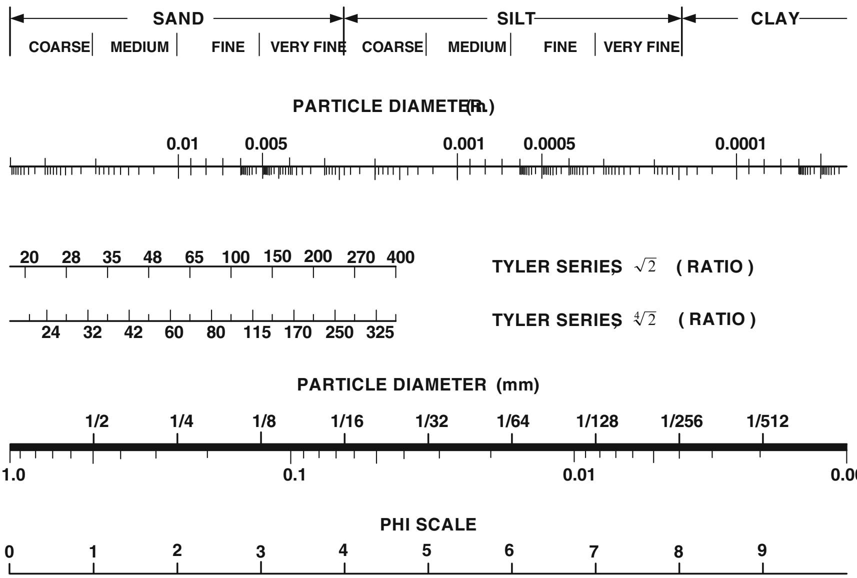


Fig. 2.3 Relation of particle size in millimeters, inches, Phi scale and Tyler standard screen series (Buzarde LE Jr et al. 1982)

Table 2.1 Sand sieve sizes (Buzarde LE Jr et al. 1982)

Mesh		Sieve opening		Mesh		Sieve opening	
U.S. series	Tyler series	(in.)	(mm)	U.S. series	Tyler series	(in.)	(mm)
2 1/2		0.315	8.00		20	0.0328	0.833
	2 1/2	0.312	7.925	25		0.0280	0.71
3		0.265	6.73		24	0.0276	0.701
	3	0.263	6.68	30	28	0.0232	0.589
3 1/2		0.223	5.66	35		0.0197	0.50
	3 1/2	0.221	5.613		32	0.0195	0.495
4		0.187	4.76	40		0.0165	0.42
	4	0.185	4.699		35	0.0164	0.417
5		0.157	4.00	45	42	0.0138	0.351
	5	0.156	3.962	50		0.0117	0.297
6		0.132	3.36		48	0.0116	0.295
	6	0.131	3.327	60		0.0098	0.250
7		0.111	2.83		60	0.0097	0.246
	7	0.110	2.794	70		0.0083	0.210
8		0.0937	2.38		65	0.0082	0.208
	8	0.093	2.362	80		0.0070	0.177
10		0.0787	2.00		80	0.0069	0.175
	9	0.078	1.981	100		0.0059	0.149
12		0.0661	1.68		100	0.0058	0.147
	10	0.065	1.651	120	115	0.0049	0.124
14		0.0555	1.41	140	150	0.0041	0.104
	12	0.055	1.397	170	170	0.0035	0.088
16		0.0469	1.19	200	200	0.0029	0.074
	14	0.046	1.168	230	250	0.0024	0.062
18		0.0394	1.00	270	270	0.0021	0.053
	16	0.0390	0.991	325	325	0.0017	0.044
20		0.0331	0.84	400	400	0.0015	0.037

(10%, 50%, 90%, etc.). The size of the screen opening which would have retained the largest part of the percentage is considered to be that percentage grain size. In practice some kind of interpolation is necessary.

Because fine particles are not defined through sieve analysis, the laser particle size (LPS) analysis (Underdown et al. 1986) is used in combination. LPS analysis is more representative of the fine particles (down to 0.1 μm), requires smaller sample (1 g), it is cheaper and quicker. The method is based on the theory which relates the intensity of light scattered by colloidal particles. By assumptions regarding the adsorption and refractive index of the particles, the particle volume passing the detector is calculated and converted to the diameter through assumption that the particle is a sphere. The problem with fines was long time solved by allowing them to pass the sand control system used. Those are in fact those parts of the rock which can move inside and between pore spaces of the rock. Practically those are all particles smaller than 44 μm. The fact is that that number results from the diameter of the finest screen in practical use. Much more the Ottawa sand (quartz, roundness, sphericity) is the most common gravel in use with grain sizes between 0.838 and 0.432 mm (20/40 mesh), and if loose packing or even tight packing is achieved it is

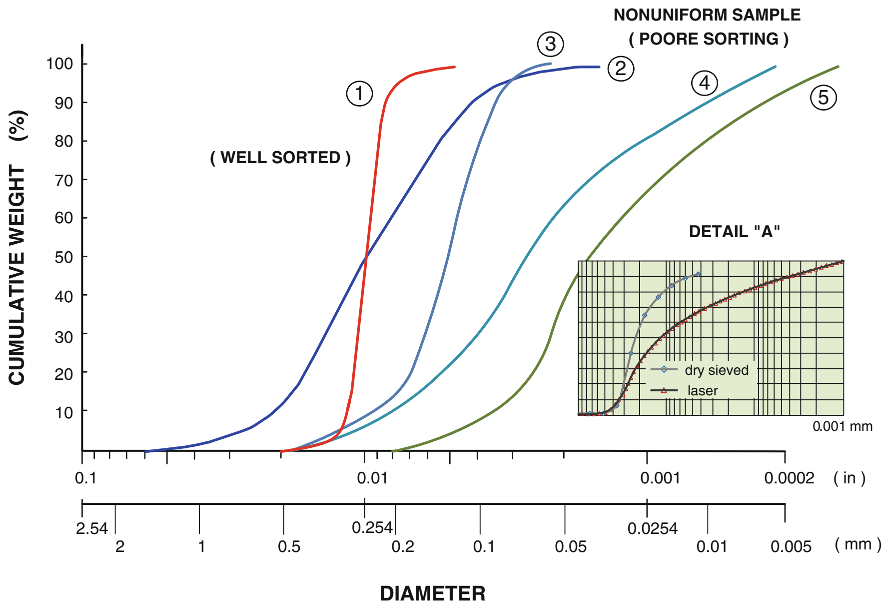


Fig. 2.4 Examples of sieve analysis: (1) uniform sample, (2) non-uniform sample, (3) gas well off-shore; depth 628 m, (4) gas well off-shore; depth 850 m, (5) oil well; depth 875 m, detail "A" difference in curve for dry sieved and laser particle size distribution for the same sample

possible that particles smaller than 38 μm pass the openings between grains, so they can be called mobile fines (Slayter et al. 2008). The problem arising with those mowing fines are: (1) resorting in the annulus and (2) production with potential plugging of the sand control system, plugging of the formation sand pores and erosion of the control system mechanical parts.

Data from the sieve analysis are plotted as the frequency distribution of weight per cent versus size range.

Sand sample (1) in Fig. 2.4 is a uniform well-sorted one with a narrow size range. The other (2) is non-uniform and poorly-sorted sand with a broad size range. Samples (3, 4 and 5) are from oil and gas fields in Croatia as stated in the graph legend.

The difference in the diameter range and curve plot between sieve and LPS analysis for the same sample is shown in detail "A" on the same picture.

The uniformity of the sand can be also determined through representation of weight percent versus particle diameter (Fig. 2.5).

Recently new method of grain size determination was introduced (Chen et al. 2010). The method combines nuclear magnetic resonance (*NMR*) logs and micro-structural rock modeling (*MSRM*). The starting point is again gravel size determination (*GSD*). GSD data is inputted in the MSRM simulation. Additional data needed are than porosity, water saturation and mineralogy information. The result is the relaxation time distribution. Simulation also takes into account different grain

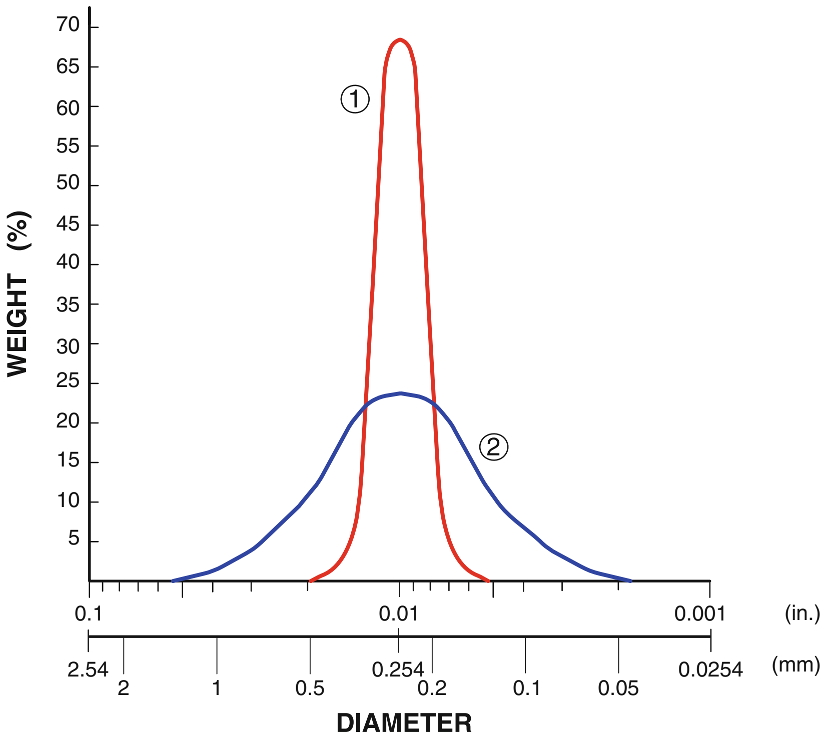


Fig. 2.5 Determination of sand uniformity through representation of weight percent versus particle diameter (1) uniform sample, (2) non-uniform sample (Buzarde LE Jr et al. 1982)

cementations and effect of clays. A surface roughness factor is also defined, because it depends on mineralogy; the amount of quartz, feldspar or clays in the rock. The result is continuous grain size distribution along the well depth realizing the variations of grain size in the formation sands.

Nomenclature

Phi From Eq. 2.1
d Grain diameter, mm

References

API Recommended Practice 58 (1995) Recommended Practice for Testing Sand Used in Gravel Packing Operations American Petroleum Institute, Washington, DC

Baker handbook – instrumentation Borivoje, Recommended Practice for Testing Sand Used in Gravel Packing Operations

Baker Hughes Inteq (1999) Coring Handbook, 503-001 Rev.c, Houston, November 1999

Buzarde LE Jr, Karl RL, Bell WT, De Priester CL (1982) Lecture notes for: Production operations course 1: Well completions. In: SPE of AIME, Dallas
Chen J, Chen S, Altunbay MM, Tyurin E (2010) A new method of grain size determination for sand-control completion application, SPE 128011. In: International symposium and exhibition on formation damage control, Lafayette, 10–12 Feb 2010
Dowel Schlumberger (1979) The Complete Sand Control Package; Gravel Pack Guide 2, A Design Manual for Gravel Pack Completions. Dowel Schlumberger, Services, Products & Technology, Technical Department, January 1979
Maly GP, Krueger RF (1971) Improper formation sampling leads to improper selection of gravel size. J Pet Technol, December 1971, Vol. 23, No. 12, 1403–1408
Slayter AG, Byrne M, McPhee CA, McCurdy P (2008) Sand management: what are we sure of? SPE 1147781. In: SPE Asia Pacific oil & gas conference and exhibition, Perth, 20–22 Oct 2008
Underdown DR, Newhouse DP, Fisher CB (1986) On-site completion/workover fluid analysis using a portable laser particle size counter, SPE 15407. In: 61st technical conference and exhibition of the SPE, New Orleans, 5–8 Oct 1986

Chapter 3
Sand Control Methods

Contents

Abstract The main purpose of any sand control method is to hold load bearing solids in the place. It is therefore necessary to determine what is in fact produced. Some fines are always produced, and that can be beneficial because that helps in cleaning pore space. The other (solids between 50 and 75 percentile ranges) that are real load bearing solids can be control through reduction of drag forces, by bridging sand mechanically or by increasing formation strength. That means some kind of production rate control, selective or oriented perforating, fracturing and gravel packing, use of screens and chemical consolidation.

In this chapter aim is to concentrate on sand control tools and procedures designed to prolong well life by eliminating sand production either mechanically trapping it behind various downhole devices or chemically consolidating the unconsolidated formations prone to produce sand. Open and cased hole installations are described, involving slotted liner, standalone screen and gravel packed completions. Through tubing sand control, frac-and-pack method completion and dual zone completions are presented as well. All these completions comprise of many different tools, accessories and devices like screens, packers, seal assemblies, running tools, blank pipes, safety joints and other. They are introduced as an overview of possible tool combinations in certain occasions.

D. Matanović et al., *Sand Control in Well Construction and Operation*,
Springer Environmental Science and Engineering,
DOI 10.1007/978-3-642-25614-1_3,

Completion as such is meant to be a link between drilling the borehole and the production phase. Without completing the well hydrocarbons are not able to flow up hole under control. As a phrase, completion involves not only the wellbore tools and accessories but all the operations designated to gain hydrocarbons to surface.

An efficient and successful sand control notably depends on well completion design and execution (i.e., drilling, casing cementing, perforating, downhole tools installation, etc.). To be able to properly design well completion many important data has to be considered, and that is reservoir pressure, temperature profiles, productivity index, water cuts, sand production volumes, formation damage, formation permeability, reservoir thickness and other. All of the mentioned has to be thoroughly investigated and affirmed as much as possible.

Once the wellbore has been drilled through the reservoir of interest, communication between the reservoir and the surface facilities has to be established through a certain pathway consisting of different tubular tools. There are three basic well completion designs (Fig. 3.1): (1) open hole completions, (2) cased hole completions, and (3) slotted liner or standalone screen completions (pre-slotted and un-cemented).

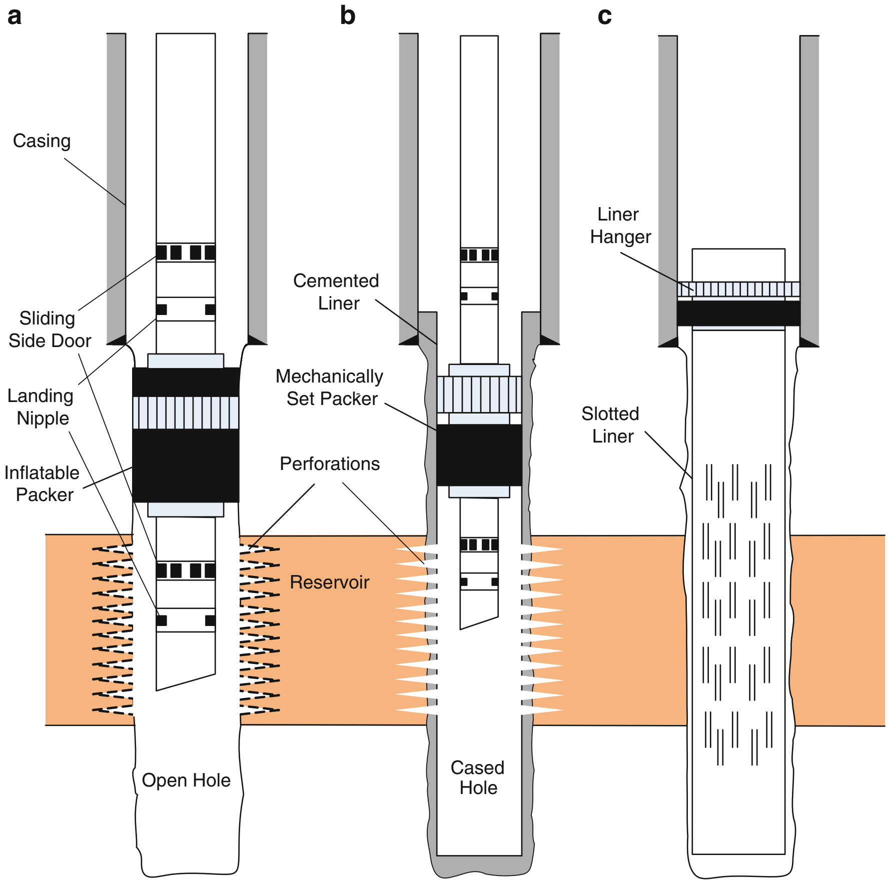


Fig. 3.1 Basic well completion designs: (**a**) Open hole completion, (**b**) Cased hole completion, (**c**) Slotted liner completion

According to illustrated open hole completion from Fig. 3.1a, hydrocarbon production from the reservoir is maintained over perforated or non-perforated reservoir up hole through the production tubing. Packer types used in these applications are various and they can be deployed inside open hole section or inside previous casing. For open hole deployment the most suitable are inflatable and swelling packers with its ability to seal rough wellbore walls. Production tubing can be set as a stand alone or anchored by the packer. Low permeability, consolidated formations with no or little sand production are suitable to be completed open hole. In special occasions, tubingless completions, also called "barefoot" completions, are used. Since the entire section is open to production, when applying tubingless completion no selective control is provided over fluid production or injection (Belarby 2009). Unstable unconsolidated formations are especially prone to sand production due to large drawdown appliance on a producing well.

If the wellbore's final section, extending across the reservoir, is cased, cemented in place, perforated and completed, it is considered to be a cased hole completion (Fig. 3.1b). If using a production casing instead of liner, it does not have to be cemented to the surface. As opposed to open hole completions, to establish communication between the reservoir and the surface facilities, cased hole has to be perforated across the reservoir depth. Packers used to anchor the production tubing and seal the casing-tubing annulus in these applications are basically mechanically set (activated by string), tension set, compression set, hydraulically set or electrically set by wireline. Zonal isolation is much better achieved comparing to open hole completions considering the selectivity options by using different tool assemblies and accessories.

Normally, various tools and accessories requirement dictates the cost of such installations, which sometimes overcomes the well cost plan. The cost of production casing from the reservoir to surface is considerably large, so liner completions are preferred.

More complex completions include selective dual/ternary completions with the ability to control zones in best possible way, incorporating dual/ternary packers, interval control devices (ICD), landing nipples, sliding side doors (SSD), temperature and pressure gauges, etc. Wells comprising of mentioned items are so-called Smart Wells (Perrin 1999; Bradley et al. 1992).

Completions consisting only of non-cemented slotted liners or different types of screens are installed after the final section has been drilled. After the liner hanger and packer elements are set, wellbore conditioned and cleaned up, well testing and production can take place. As shown in Fig. 3.1c, slotted liners, usually made of steel or fiberglass, have small diameter slots pre-made at the workshop for the purpose of stopping redundant sand production. However, sand grains can be stopped only if the slot width is of adequate dimension according to sand grains that are produced. Slots may quickly become plugged if the completion design is not done correctly. So-called standalone sand screens are installed without gravel packing the annulus between the screen and wellbore wall.

Both slotted liners and standalone screens are low cost alternatives to ordinary cased hole completions with or without production tubing string use. These facts reduce the total well cost (Perrin 1999; Ott and Woods 2003).

Installations mentioned may be gravel packed to place a filtering zone between the reservoir and wellbore. This part of well completion and sand management will be explained in details later on.

When deciding which particular sand control method to use, the balance among engineering approach and economic return is needed. Also the advantages and disadvantages of each method for each job should be considered. Possible methods that should be considered are:

1. Restricting of production rate. The idea is to reduce the drag force due to fluid velocity. The determination of maximum sand-free production rate is complex and complicated by the time dependent conditions in the reservoir, especially if preceded by water production.
2. Increasing flow area. The problem appears in cased hole completions and can be solved by increasing the perforating shot density and size. That will help to reduce the unit flow velocity at the wellbore below critical values for sand production.
3. Selective perforating. That can be beneficial because only the strongest portion of the pay zone can be detected using a mechanical properties log. Unfortunately all these methods restrict the maximum recovery rates and the longevity of control is altered by the formation change with time.
4. In-situ sand consolidation techniques. All of them use an artificial tackifying material, and in use from 1940s. It relies on effective placement of the chemical (resins) through the entire zone. They have been the most popular method between 1950s and 1960s, when the gravel packing method was improved.
5. Resin-coated gravel pack. That is the modification or combination of the chemical consolidation and gravel pack method. It uses a grave precoated with resin that is injected in the formation. After the polymerization process the excess material in the well must be drilled out.
6. Mechanical methods. They involve use of screen to retain the formation sand (with or without gravel) or use of gravel to hold formation sand (with or without a screen to retain the gravel). The use of gravel packing is today the widely used method of controlling sand production. In fact it means to place a granular filter in the annular space between an unconsolidated formation and a centralized slotted liner or wire-wrapped screen.

Simple and acceptable approach has been proposed (Patton and Abbot 1979a) that defines the approach to the objectives of well completion and the data needed. Because the primary objective of a well completion is to achieve a desired amount of production and to hold costs to a minimum, the completion should be simple, reliable and safe, while maintaining as much flexibility as possible for future operations.

The geologic and engineering (technical) information that are gathered provide input for making sound decisions at various steps in a completion program. Such data are the geologic, engineering, drilling, and formation damage data listed in Table 3.1. They are the environment in which one must work while trying to achieve the objective. The environmental factors are used to:

Table 3.1 Input data: environment and resources (Patton and Abbott 1979)

Engineering data (E)		Data resources
E-1	Fluid properties	Oil, water, gas (analyses)
	p, v, t, chemical composition	
E-2	Initial reservoir pressure	Well tests
E-3	Reservoir drive mechanism	Geology, production charact.
E-4	Rock properties	Core analysis
E-5	Production characteristics	Production records
E-6	Completion, workovers	Well files
E-7	Subsurface equipment failures	Well files
E-8	Grain size distribution	Sieve analysis
E-9	Formation strength	Mechanical properties log
E-10	Formation solubility	Lab testing
E-11	Reservoir properties	Transient well tests
	Pressures	Flow and buildup curves
	Permeability	Multirate
	Continuity/heterogeneity	Isochronal
	Formation damage	Shut-in BHP
	Inflow performance	
	Gas deliverability	
E-12	Fluid entry/loss	Temperature logs
	Type	Flowmeter
	Amount	Differential manometer
	Location	
E-13	Sand production	Multirate tests
Geologic data (G)		Data resources
G-1	Trap classification	Geophysical/geological data
G-2	Rock properties	Open-hole logs, mud log
G-3	Rock types/mineral content	Petrophysical analysis
G-4	Fractures, solution channels	Core analysis
G-5	Stratification	Cores and logs
G-6	Other formations of interest	
	Hydrocarbon bearing	
	Aquifers	
	Potential gas storage	
	Thief zones	
	Salt or anhydrites	
Formation data (FD)		Data resources
FD-1	Clay swelling	Laboratory testing
FD-2	Plugging	Flow and backflush tests
FD-3	Relative permeability	Special core analysis
FD-4	Wettability changes	Laboratory testing
FD-5	Emulsion or water blocks	Bottomhole sample
FD-6	Deposits	Oil and water analysis
FD-7	Potential damage	Compatibility tests:
		Liquid to liquid
		Liquid to formation
Drilling records (DR)		Data resources
DR-1	Washouts/cavities	Caliper log
DR-2	Lost circulation zones	Daily drilling records
DR-3	High-pressure zones	Daily drilling records

– Define the objective and establish constraints (limits) that may affect the completion results,
– Eliminate as much guesswork as possible to insure success of the program,
– Point out potential problems (before they occur) and help establish differences between problems and their symptoms,
– Establish the economic picture – cost and payout – to aid us in evaluating the success or failure of the program,
– Show the need for additional information that will benefit design and operations, and
– Plan the completion program.

The next step is to prepare completion design program (Fig. 3.2) that shows the interrelation of gathered data. For unconsolidated formations both cased and open-hole completion are considered. Input information shown at the top of the flow chart is about reservoir drive mechanism, present and future (E-3), history of completions and workovers (E-6), grain size distribution (E-8), formation strength (E-9), rock properties (G-2), stratification (G-5), formation damage (FD) and drilling records (DR). In that decision point it is possible to select between cased hole and open hole. If cased hole is selected there are three possible sand control methods: (1) rate control, (2) chemical consolidation, and (3) inside gravel pack. Additional data in decision making process would be: fluid properties (E-1), rock properties (E-4), history of production characteristics (E-5), grain size distribution (E-8), fluid entry (E-12), rock properties (G-2), clay, silt, shale type, and mineral content (G-3),

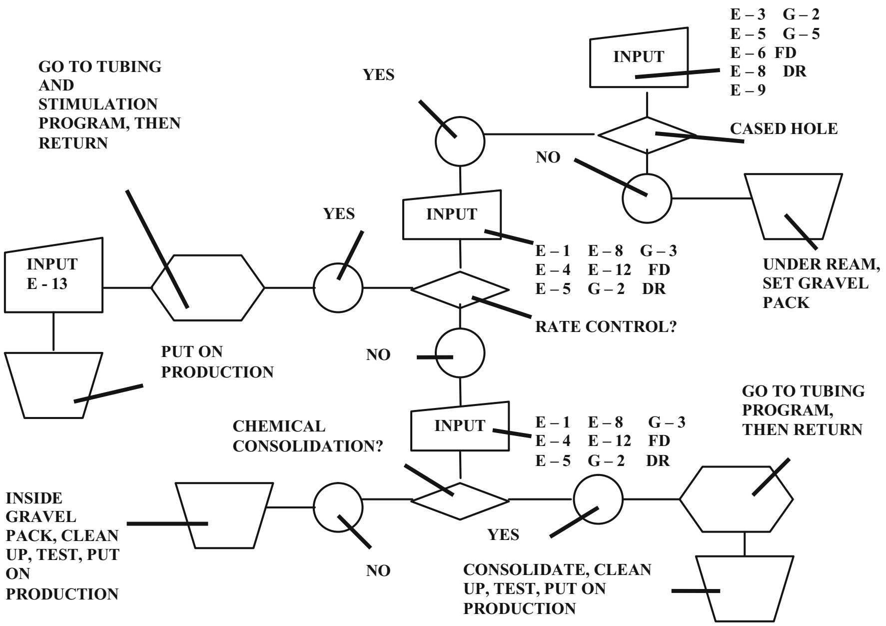


Fig. 3.2 Design program when completing unconsolidated formations (Patton and Abbott 1979)

formation damage (FD) and drilling records (DR). Some data have been repeated, but are looking at the criteria from a different viewpoint and for a different purpose. If rate control is selected, there is the need for another input data obtained by rate-sensitive sand production test (E-13). For any other considered method it is possible to broaden the algorithm and add necessary data.

To avoid misleading due the possible completion or treatment method for sand control, some guidance (Ott and Woods 2003) according to reliability, productivity impact, costs, possible control of water or gas inflow and major short-comings (Belarby 2009) are given in Table 3.2.

As a quick reference to assist in selecting the most appropriate sand control treatment to use for various conditions, it is also possible to use data from Table 3.3.

3.1 Restriction of Production Rate

The most effective, simplest and with lower cost is the method that uses the restriction of production rate to control the sand production. It depends on the amount of the specific fluid that can be produced without excessive sand production (unless it is desired). Analysis is done based on the data about fluid types, rock characteristics, flow rates, and pressure drawdown in the well. The best approach should be the individual well test. That means to produce the well with gradually increasing rates until sand is produced, or the maximum acceptable production rate is obtained. Such method named also "bean-up" technique provides also ideal clean up of fines from the pore channels around the well bore. The method is based on the fact that during steady state flow natural arches will be established controlling the sand production (Fig. 3.3a). Increasing step wise flow rate, sand concentration jumps (Fig. 3.3b) at the increase and then tapers off to the previous concentration. But when critical fluid velocity is reached bridges do not form and the sand production continues. So the production rate must be reduced and hold bellow critical range.

3.2 Mechanical Methods of Sand Control

Mechanical methods of sand control use slotted liners, screens and gravel pack (or combination of both) to hold sand in formation. There are three basic design parameters here: (1) optimum slotted liner or screen slot width (with and without gravel), (2) determination of optimum gravel size and distribution, and (3) effective placement technique. The simplest type of screen is slotted liner, but they are not sufficient in most cases. The extent is the use of wire-wrapped liners (screens). They are the next cheapest method available. Because they rely on the natural sand arch forming on the openings, it is necessary that some amount of formation sand forms such barrier. Shortcoming of such method is in fact that it reduces the wellbore

Table 3.2 Comparison of main sand control methods

	Reliability	Productivity	Cost	Zonal isolation	Major short-comings
Rate control	Small due the changes in formation through the time	Low due the maximal fluid velocity allowed	No cost in comparison with other methods	Dependent on type of completion	Constant sand monitoring, separation, and disposal required. Erosion problems and potential loss of production
Selective and oriented perforating	Dependent on available data on formation strength and heterogeneity	Lower due the restricted flow area opened to the formation	High due the perforating and orientation tool expenses	Good if primary cementing was checked	Homogenous formations are problematic. Need for formation strength data and theoretical analysis
Standalone and expendable screens, slotted liners	Poor in heterogeneous formations can be improved by inflow control devices and good testing	The highest when no plugging	Low, but some expenses rise due the amount of sand production, disposal costs	Some improvement achieved by the use of swellable packers (more information needed)	Zonal isolation my be a problem, possible plugging and screen collapse, erosion or damage during installation
Open hole gravel packs	Good if proper fluid selected and complete volume packed	Minimal skin if no fines invasion exists, possible with water encroachment	Medium because some extra equipment costs rise due pumps and fluid mixing	Almost none	Under-reaming necessary. Reduction of productivity index
Cased hole gravel packs	Better control than open hole due the known volume	Positive skin factors due the change in system permeability	High cost according the casing run, cementing and perforating	Very good due the selectivity and large zonal isolation	High cost of installation and operation complexity
Frac packs	High reliability (need to control proppant flow-back)	High in moderate and heterogeneous formations	Very high (chemicals, proppant, pumps, mixing equipment	Problematic if fracturing into water or gas contacts	Risks of tip-screenout and proppant flow-back on production
Chemical consolidation	High but depends on volume covered	Smaller than original	Very high	Very good	Acceptable only for short intervals. Problems with placement may impair reliability

Table 3.3 Sand control method selections (Durrett et al. 1977)

	Installation cost	Sand size	Sand size distribution	Wellbore restrictions
Screen	Low	Medium/large	Broad	Yes
Gravel pack	Medium	Small/medium	Medium/broad	Yes
Consolidation	Highest	All	All	No
Resin coated pack	High	All	All	No

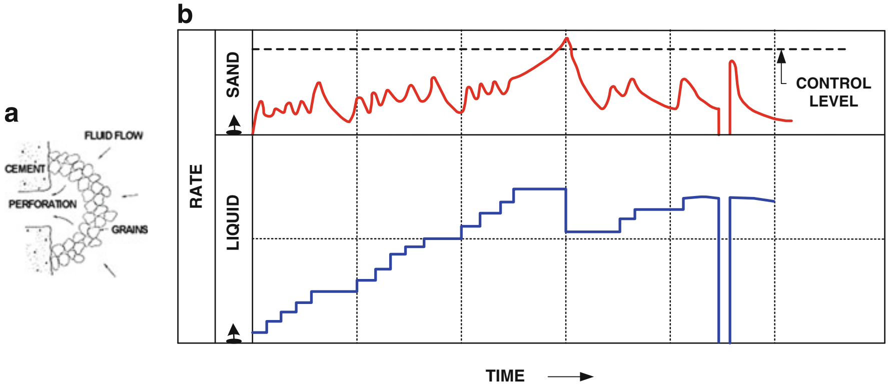


Fig. 3.3 Forming of natural bridges (**a**) and determination of sand production in accordance to flow rate (**b**) (Allen and Roberts 1978)

diameter. Also if the formation contains fines (fine sand, silt and clay), infiltration of these particles can alter the flow or cut out the screen.

Gravel packing is the improvement of the previous method. That means to spot gravel pack around the screen or even pressure pack graded sand outside the casing deeper into the formation. The main task of the gravel (clean, graded sand) is to restrict movement of the formation sand (grains). The method is more costly than previous, but can be less expensive than a sand consolidation treatment. The comparison of sand control systems was of concern all the time of implementation. One of the first was done by Coulter and Gurley (1970), where it was highlighted that in the future any generalization or statement must be avoided due to many factors that affect the quality and reliability of control method used. Nevertheless the issue of economics can have great impact on method selection. It has also stated that gravel pack method has a great advantage because of the tolerance of variations according the volumes, flow capacity and the time available. The main problem again is in appropriate gravel pack sizing to stop the formation sand movement, and also as very important part is the good placement of the gravel pack meaning that all voids are filed and the gravel is in a dense and stable packing arrangement, what includes the term compaction.

3.2.1 Slotted Liners

Sometimes, slotted liners are used without gravel pack placement to control formation sand production. One of the common applications is in reservoirs that produce high-viscosity oil from horizontal wells drilled through unconsolidated, high permeability sands (Kaiser et al. 2000). In this case formation has to be well consolidated and sand grains well sorted. If the formation is not well sorted and the produced sand not clean with large grain sizes, this type of completion has fairly short producing life before liner plugs with sand. That is because in long horizontal sections accompanied with low inflow rates, fluid cannot transport even small formation grains through the well out to the surface. Due the low economics of such wells they are usually completed with low-cost sand control system, such as slotted liners. Slotted liners should provide the sand control based on bridging or are used to restrain gravel. So, the main reason for gravel packed liners installation would be better sand management by obtaining an additional sand filtering zone (Fig. 3.4). Usually, when gravel packing open hole, it is preferable to ream the wellbore across the reservoir with under reamer for greater gravel thickness around the liner providing for productivity increase.

Slotted liners for gravel packing have slots specially machined in workshop. Their orientation can be perpendicular or horizontal along the liner with different arrangement and sizes. Quantity of slots depends on the flow area of the slotted liner. Generally speaking, 2–3% of total external surface area of the liner is taken as the total area of the slots. Slots number can be determined from the following equation:

$$n_s = \frac{\alpha_s F_s}{w_s l_s} \tag{3.1}$$

Number of slots per 1 m of the liner (n_s), is determined according to the total slot area of total external surface area of the liner α_s, external surface area per meter of the liner (F_s), width of slotted aperture (w_s), and slot length (L_s) (Renpu 2011).

According to slot shape, there are normal straight slots and tapered shape slots, providing a non-plugging mechanism. Figure 3.4 also shows the difference between straight slots often having problems with plugging by sand particles and tapered slots which do not allow for clogging. Commercially available slot widths have for a long time been restricted by the industry. Slot widths are usually ranging from 0.127 to 2.286 mm. Small width slots (0.127–0.991 mm) are produced with tolerance of ±0.0254 mm. The slot size for straight cut ranges from 0.3048 to 12.7 mm, and for undercut slots the width range is from 0.508 to 12.7 mm. Also available are liners with horizontal slots ranging in width from 0.252 to 2.286 mm. The main disadvantage of slotted liner in spite of relative low initial cost is in having the smallest sloth widths being too large for stopping the sand production. Also when compared to wire wrapped screens they have relatively small inlet area. Because of that they should be susceptible to erosion. Recent developments in

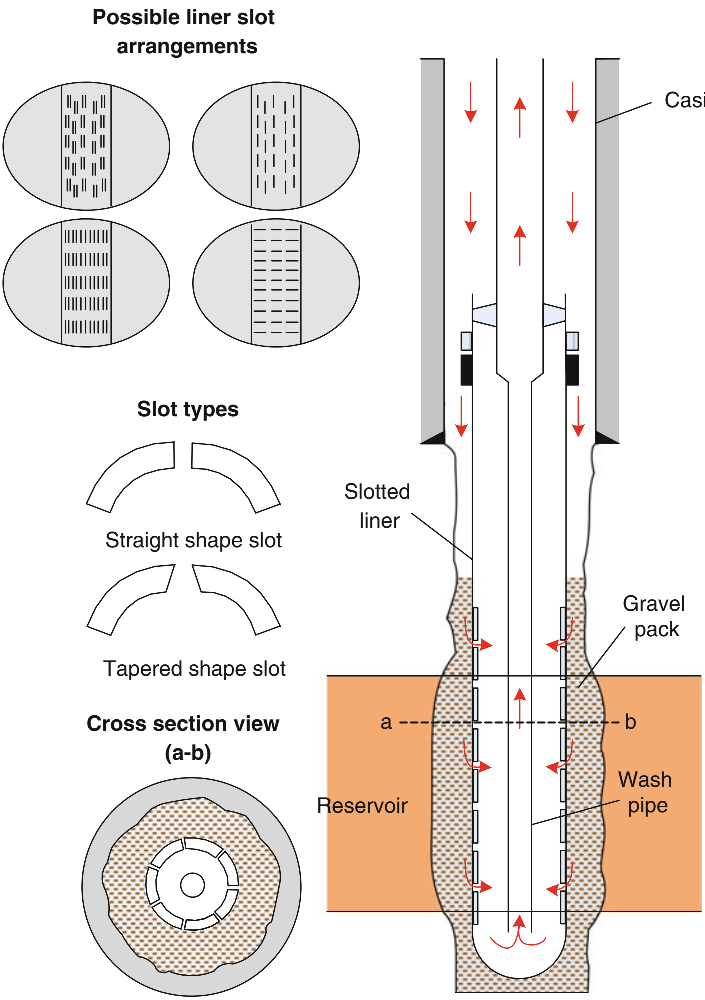


Fig. 3.4 Slotted liner completion

slotted liner technology enable cutting of very small slot widths being less than 0.12 mm. That helps to improve anti-plugging characteristics of slotted liners.

Regardless the slot dimensions it has been shown (Kaiser et al. 2000) that the pressure lost through an open slot is negligible compared with the pressure drop induced by the flow convergence associated with the slot, when compared to barefoot radial fluid flow (Fig. 3.5).

All mechanical sand-control methods influence the change in flow from the reservoir to the production string. Such flow disturbance (convergence) creates higher pressure loss that is defined as skin. Using numerical analysis it is possible to find relations among such skin (slot factor) and slotting parameters. The results of investigations have shown that for a given open area the pressure loss is reduced

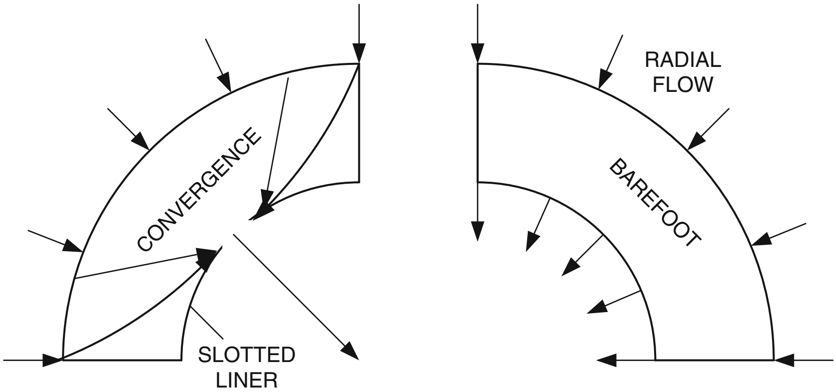


Fig. 3.5 Convergence of radial flow through liner slot (*left*) compared to barefoot radial flow (*right*)

with reduction of slot size (width). But the reduction of slot width must be approved with the results of slot plugging tests. The keystone-type slot profile is mostly used in such cases due their anti-plugging characteristics. So the slot geometry should be chosen to preclude sand entry and to prevent bridging of sand particles inside the slot Krumbein and Pettijohn (1938), (Markestad and Christie 1996).

3.2.1.1 Expandable Slotted Tubular

Expandable slotted liners have been developed to improve well production and reduce sand production with reduction of well costs at the same time. The main concern when using such pipes (liner, casing or screen) for sand control purpose should be about slot size based on deformation after expansion. For the purpose of post-deformation determination the study has been conducted (Li et al. 2007) that has provided the industry with the analytical model for calculation of slot deformation, axial tension and compression slotted pipe ratings.

Slots on expanded tubular are always done along the length of the pipe. In the well, slotted-expandable liner is lowered to the desired depth on the drill pipes or tubing. The expansion is done by the use of a cone (Fig. 3.6) that can be hydraulically expanded to the desired diameter. Expansion starts at the bottom of the slotted liner by lifting the cone up to the top of the slotted pipe. Releasing the pressure allows the cone to shrink back to smaller size. That is because the tubular joints are not slotted and cannot be expanded. The process is repeated according to the number of slotted pipes in the string. If there is the need to retrieve slotted-expanded pipes, the drill string and the pulling force should be applied to collapse back the expanded slots.

Originally slots are rectangular. After expansion their shape is octagonal as shown in Fig. 3.7.

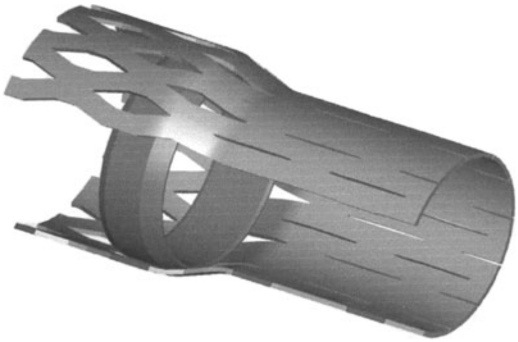


Fig. 3.6 Slotted pipe expansion (Weatherford 2003)

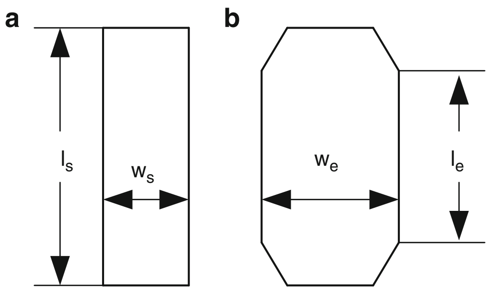


Fig. 3.7 Slot shape: (**a**) original; (**b**) after expansion

The assumption used to calculate the change in slot width is that after the deformation the width and wall thickness of steel strips between two slots do not change the dimension. Then the slot width on the expanded pipe w_e is expressed as:

$$w_e = \frac{2\pi}{m}\left(D_f - D_i\right) + w_s \tag{3.2}$$

where m determines the number of links between slots over the pipe cross section area, D_f is the final (expanded) pipe outer diameter, D_i is the initial outer diameter of the pipe, and w_s is the sloth width before expansion.

3.2.2 Screens

Simplicity and considerably low installation cost of standalone screens (Fig. 3.8) stand out as a reason of their world wide use. Installed inside the open hole section without the gravel pack placement, such completions incorporate different screen types (wire wrapped, pre-packed, premium, expandable sand screens, etc.), inflatable and swellable packers, inflow control devices and other specially designed

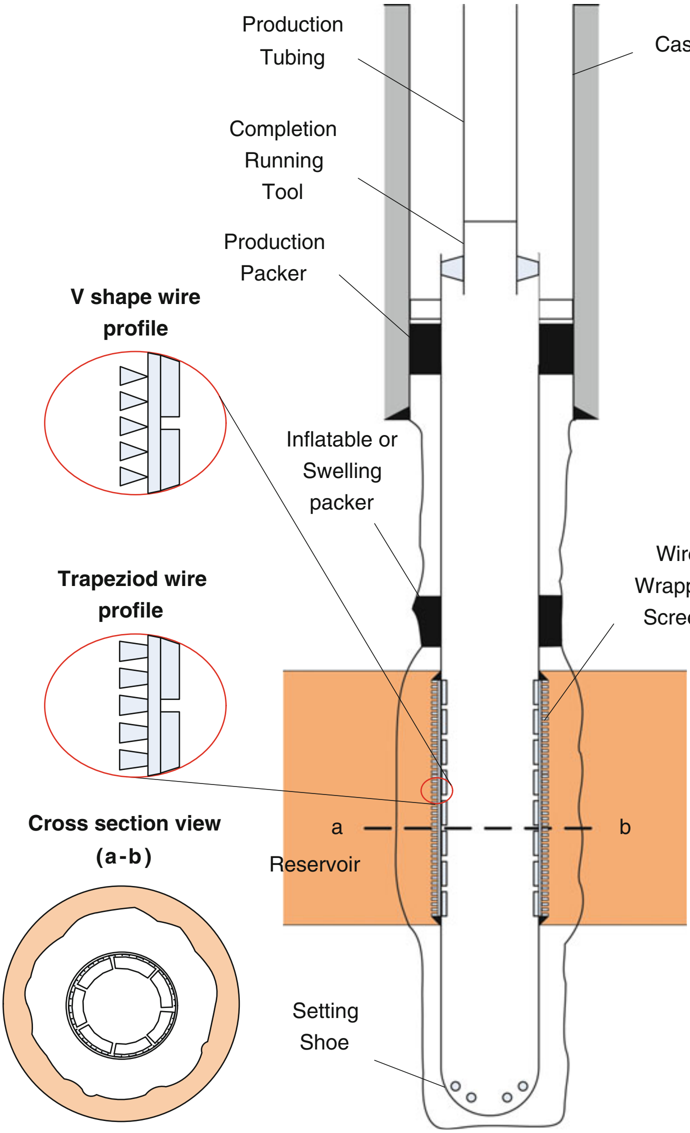


Fig. 3.8 Standalone screen completion

tools. Zonal isolation inside open hole is resolved by inflatable and swelling packers praised for excellent swelling and sealing ability when completing more intervals.

These screen installations without gravel packing can be set with or without wash pipe, but mainly without it, as during the completion run wellbore is conditioned or mud displaced. Since there is no gravel pack zone around the screen, all produced sand grains gather around it plugging the screen slots which leads to screen disruption. That is why sand quality considerations are extremely important when designing a standalone screen completion. Being a delicate devices, screens are tools mainly made of stainless steel specially designed to stop sand from entering and eroding completion and surface facilities. Hydrocarbon production should not be limited due to screen installation, so it is one of most important things to consider when deciding which type of screen and aperture size to use. Simplicity and considerably low installation cost of standalone screens stand out as a reason of their world wide use. Installed inside the open hole section without the gravel pack placement, such completions incorporate different screen types (wire wrapped, pre-packed, premium, expandable sand screens etc.), packers, inflow control devices and other specially designed tools. Zonal isolation inside open hole is resolved by inflatable or swelling packers praised for excellent swelling and sealing ability when completing more intervals.

When choosing a proper screen type and dimensions for open hole standalone screen completions following considerations should be taken into account: (1) screen strength and damage resistance, aperture size, plugging and erosion resistance, laboratory testing with formation sand samples, previous jobs experience (Ott and Woods 2003).

As previous mentioned there are many different types and mechanical solutions for screen design (Fig. 3.9): wire wrapped screens, pre-packed screens, premium screens, special design screens, through tubing small diameter screens, alternate path screens, and expandable screens.

3.2.2.1 Wire Wrapped Screens

Wire wrapped screens designed for both vertical and horizontal completions consist of perforated inner pipe, longitudinal elements (rods) welded on it and a steel wire shrink fitted (direct wrapping) around the pipe or welded to the rods. Examples of wire wrapped screen can be seen in Fig. 3.9a having trapezoid or “V” shape profile wire positioned around the pre-drilled holes on the base pipe. Usually they are used in standalone and gravel pack completions. Some of those screens are much lighter, specially made for horizontal sections installation and some have different wire or rod shape connected to various types of perforated inner tubes. Some screens are even a multilayered devices consisting of more than two wire layers with the outer layer having the largest slot openings (Halliburton 1994).

When choosing a proper screen type and dimensions for screen completions following considerations should be taken into account: (1) screen strength and damage resistance, (2) aperture size, (3) plugging and erosion resistance, (4) laboratory testing with formation sand samples, and (5) previous jobs experience.

All the screen parts are made of high strength and corrosion resistant materials. The screen total flow area depends on slot width, wire thickness and screen length, and usually is quite large comparing to cased and perforated well inflow area, so it results with lower fluid entrance velocity at the screen front. Permeability of such screens is also much greater then the reservoir’s (Belarby 2009; Suman et al. 1983)

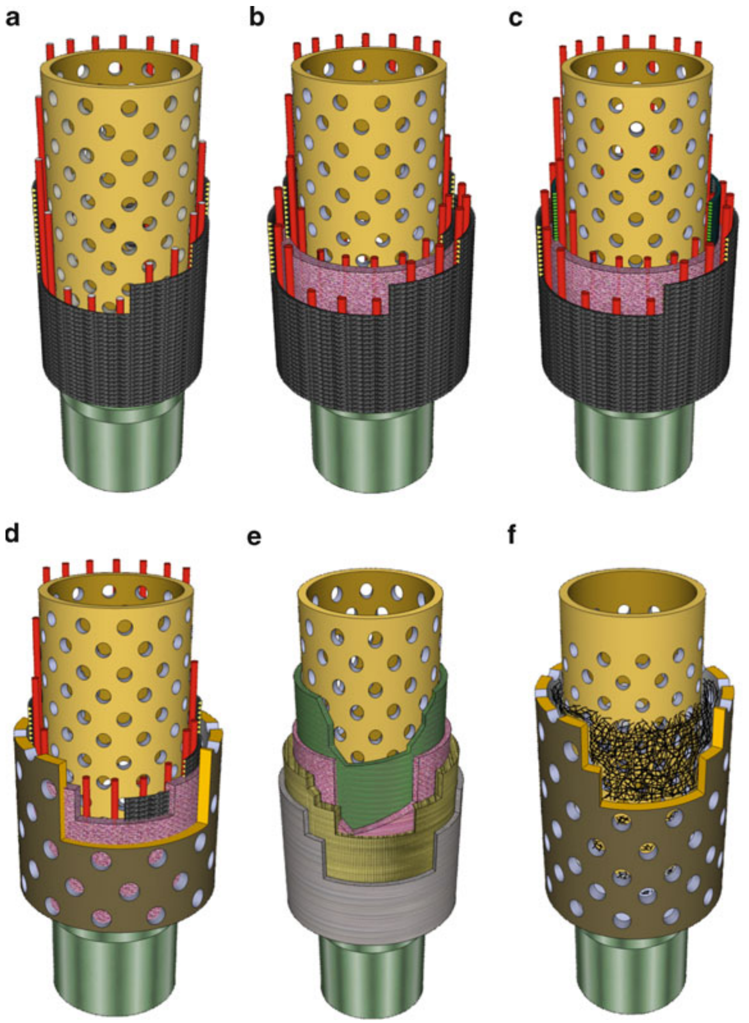


Fig. 3.9 Some of possible screen types: (**a**) Wire wrapped screen, (**b**) Double layered pre-packed screen, (**c**) Single wire pre-packed screen, (**d**) Double layered pre-packed screen with a micro screen, (**e**) Premium screen, (**f**) Wool wrapped screen

3.2.2.2 Pre-packed Screens

This type of screens is mainly designed for application in inclined wells of special requirements. A wide array of pre-packed screens is available today. According to Fig. 3.9b, double layered wire wrapped screens are gravel packed between the inner and outer wire layer while single wire pre-packed screens (Fig. 3.9d) are gravel packed between the wrapped wire and the outer perforated shroud. Some types of double layered pre-packed screens have a micro screen (Fig. 3.9c) instead of wire wrapped screen with gravel pack between them. Wire is mostly welded onto rod for greater stiffness and handling ability.

Gravel pack inside the screen usually has a very good permeability and combining it with a large inflow area of the wrapped wire layers a minor pressure drop is observed across the screen (Harrison et al. 1990).

However, some shortcomings of this type of screen are a breakable nature of the screen gravel packs and a potential for plugging it. Despite the mentioned, pre-packed screens are worldwide used in many open hole and cased hole gravel packed or standalone completions.

3.2.2.3 Premium Screens

Premium screens, as shown in Fig. 3.9e, are very expensive sand control solutions comprising of many different non pre-packed sand excluding sintered woven wire layers around the perforated inner pipe. Some layers are used for sand filtration while others are used for the fluid drainage or interior protection. Although the outer screen layers are also used as filtering fronts, their primary task is to protect the inner layers from possible damage occurrence.

Sintering the wire provides better mechanical properties of the screen making it a robust device capable of withstanding the highest pressures and inflow rates. Wire weave pattern can be either Dutch weave or square weave depending on desired slot size. Loads distributing through downhole equipment affect only the inner pipe so the rest of the screen parts are left unstressed. Moreover, premium screen protective layers and wire layers are thicker and stronger than the other screen types which make them very enduring (Belarby 2009; Ott and Woods 2003).

3.2.2.4 Special Design Screens

This screen type, made mainly for standalone applications, includes different wool wrapped screens (Fig. 3.9f) and various high grade alloy and chrome screens resistant to corrosion with excellent mechanical integrity.

Wool wrapped screens are a different type of specially designed screens consisting of stainless steel wool wrapped around the perforated inner pipe and covered with the outer shroud. Like through tubing screens, wool wrapped screens are designed to retain all sand grain sizes as well. High permeability of the screen indicates a high flow performance without losing too much of reservoir pressure. High corrosion and erosion resistance makes this type of standalone screen a perfect alternative to gravel packed applications.

High grade alloy and chrome screens are designed to apply in high pressure/high temperature wellbore conditions. Being resistive to sour gases like hydrogen sulfide and carbon dioxide, these screens are fit for harsh downhole environment.

3.2.2.5 Through Tubing Small Diameter Screens

Screens meant for through tubing applications are usually a small diameter premium sand control screens using innovative press-and-fit assembling methods to ensure the highest burst and collapse ratings of premium mesh layers. Modern weaving technologies are used to provide the highest inflow areas and maximum plugging resistance. Multilayered through tubing gravel pack screens are designed for better support, drainage, filtration, convergence and protection of the inner layers. When designing such a screen special attention should be given to screen inner diameter which has to be the largest possible, so very thin layers surround the base pipe (0.8–2.0 mm). They are made by wrapping a special stainless steel fiber around the base pipe and compressed to form apertures. The weave is pressed against the outer and inner screen layers and does not utilize welding connection.

Figure 3.10 shows a small diameter screen cross section views showing different inner and outer layers not thicker then 2.0 mm. Outer protecting layer/shroud is press-fit against the inner layers to provide complete entrapment ensuring maximum protection from pressure fluctuations (Lake and Clegg 2007; Halliburton 1994; Baker Oil Tools 2002; Tendeka Screens 2011).

3.2.2.6 Alternate Path Screens

During the gravel pack operation execution, proppant laden slurry might dehydrate inside screen/casing annulus at the early stage of operation, so a blockage may occur due to high proppant concentration as the slurry becomes non-pumpable. To be able to pump a proppant laden slurry, it has to have good rheological properties, and that is an optimum viscosity, density and proper fluid loss additives addition.

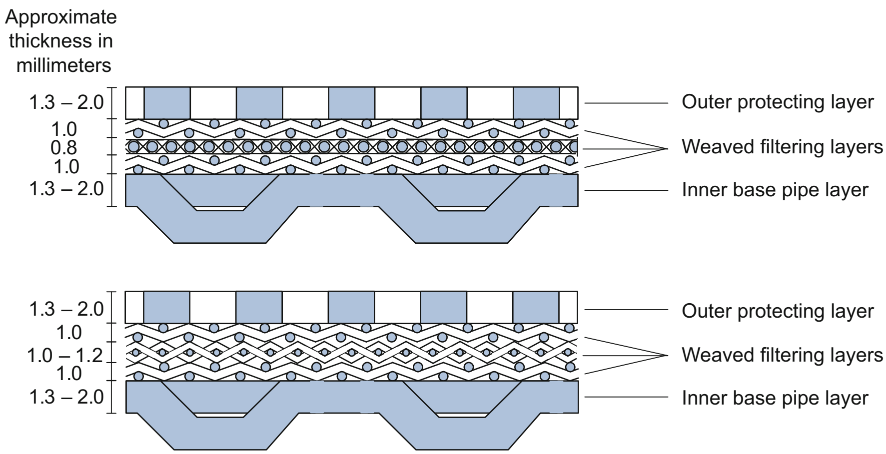


Fig. 3.10 Through tubing small diameter screen cross section (Tendeka screens 2011)

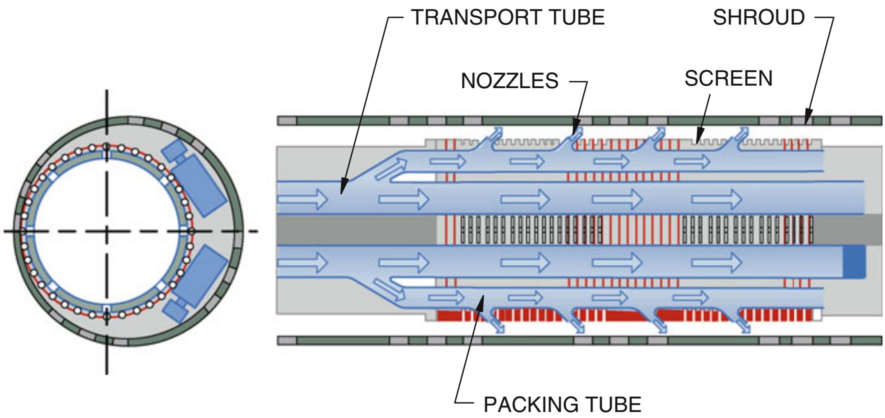


Fig. 3.11 Alternate path screen with shunt tubes (Ott and Woods 2003)

Premature screen-out and proppant pack-off issue is easily solved by using an alternate path screens consisting of few rectangular or round tubes (Shunt tubes) welded on the outside of screen body with or without protective perforated shroud (Fig. 3.11).

There are two types of tubes used – *transport tubes* and *packing tubes* (Hecker et al. 2010). Transport tubes transport the slurry from one screen joint to another along the whole completion and deliver it to packing tubes used for gravel packing. For the purpose of being able to fill the voids bellow the bridging location; packing tubes have exit ports (nozzles) along the tube body. Obviously, shunt tubes offer an alternate path for slurry when bridging occurs. They are usually made of alloyed steel sintered with carbide layers for protection from extreme erosion environment.

With the help of alternate path packers several separated zones can be gravel packed one at a time. After gravel packing the upper zone, transport tubes deliver the slurry to lower zone through the packer. Packing tubes are then fed with slurry via transport tubes and lower zone is gravel packed through the exit ports.

Alternate path approach is applied in gravel pack and frac-and-pack operations no matter open or cased hole, vertical or horizontal oriented wellbore (Ali et al. 2002; Romero et al. 2002; Hecker et al. 2010).

3.2.2.7 Expandable Screens

When installing conventional sand control equipment a higher well cost should be considered, especially if it is gravel packed. Time consumption and thus money is a primary reason of more often moving from conventional to expandable screens. Deployment of regular sand control assembly and gravel packing is not only more demanding operation then expendables deployment (safety and operationally wise) but also more expensive.

Expandable screens usage eliminates the annulus allowing greater space for downhole tools manipulation and supporting the borehole. That way sand exclusion is achieved without gravel packing.

Manufactured expandable sand screen joints are connected using expandable sand tight connectors and consist of slotted base pipe, filtering media (layer) and outer protective shroud. Base pipe is an expandable pre-slotted tubular capable of widening to wellbore wall interface with other layers. Filtering layer also has to be deformable. The rate of deformation can be modified by choosing different materials for layer make. It can be made of woven metal, micro slotted plates or sintered metal membranes (Metcalfe and Whitelaw 1999; Van Buren and Van Den Broek 1999). These plates overlap each other, so a substantial extension is allowed integrating a good sand exclusion at the same time. Outer protective layer keeps filtering layer in place and protects it from aggressive abrasive downhole conditions.

Screen expansion is accomplished by forcing a widening device downwards through the string. Popular methods to do that are depicted in Fig. 3.12a: fixed diameter cone expansion, fixed rotary expansion with rollers, and hydraulic expansion method.

Cone expansion is achieved by running a conical wedge through the string and pressing it against the wellbore wall. The screen usually expands a bit more over the wedge diameter (2–3%) for safe trip out of the hole. Rollers expansion is done by pressure activating the pistons, pushing the rollers against the screen and thus expanding it. This type of expansion is done quite fast comparing to others.

Hydraulic expansion is applied when large forces are needed to expand the screen. The assembly consists of expansion cone, piston, anchors and a valve with appropriate seat size for the ball. While anchors grip the expanded screen section, ball sets onto the valve seat and piston moves the cone downwards due to pressure appliance from the surface. This type of expansion is much slower then the previously mentioned. When either of these techniques is used, expandable joints can be expanded up to 80–100% of its original diameter (Innes et al. 2005). Expanded screen joint cut section is shown in Fig. 3.12b.

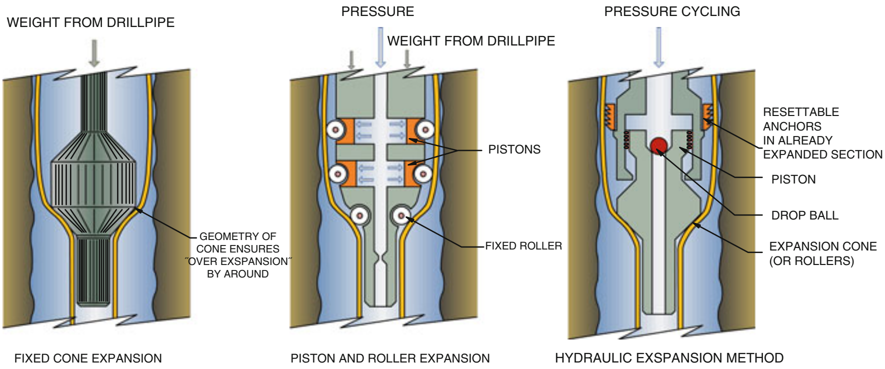


Fig. 3.12 Expandable screen expansion methods (Belarby 2009; Innes et al. 2005)

Nowadays, expandable screen joints are very often used in tandem with solid expandable tubulars and swelling packers (zonal isolation). Solid expandables provide for zonal isolation by expanding to the wellbore wall interface. They have an elastomeric cloths bonded to the pipe which ensure a good seal between the formation and the pipe. Swelling packers start to swell when they are emerged into the wellbore fluid (oil swelling and water swelling packers). While swelling, mechanical properties degrade. Sealing capability largely depends on the wellbore diameter, packer diameter, wellbore temperature/pressure conditions, water salinity and elastomer composition.

The major benefit from expandable sand screens is a large inflow area once expanded.

3.2.3 Screen Design and Selection

Screen section length depends on perforated interval length and it should extend 1.5–2.0 m above and below perforations.

Screen type selection depends on the operator practice and downhole conditions. If the gravel pack operation is to be done in HP/HT (high pressure – high temperature) environment with H_2S occurrence, premium or special design screens are used. Mainly, they are made of high grade alloys and chrome resistant to corrosion. But, if downhole conditions are not aggressive, cheaper versions like wire wrapped screens are installed instead.

Many laboratory and field studies have been dealing with sizing of screens as sand control media. One of the first published (Coberly 1983) proposed guidelines for sizing slot (screen) openings based on formation sand grain size with implication of some acceptable sand production. The idea was to enable sand retention by forming of stable bridges. The upper limit of the slot width w_s was twice a diameter of the grain size at the 10 percentile point ($w_s \leq 2 \cdot d_{10}$). Because of the frequent failure of so designed systems, lot of failures occurred. That has lead to next width recommendation, that the width of the slot or distance between wires be less or equal to 10 percentile point ($w_s \leq d_{10}$) (Suman et al. 1983). The mean drawback of such criteria is that they use only one parameter from the particle size distribution curve as the representative for the entire distribution. The change on the market and in the practice has happened after the method that represents the entire particle size distribution range was introduced (Markestad and Christie 1996). The result was a numerical model based on laboratory investigations dealing with plugging and production through single wrapped screens, related to particle size distribution. Plugging is the result of bridging of screen slots with larger particles, than can be retained by the slots. The formation sand as a mixture consists of a wide range of particles with different sizes. So the smaller particles can fit into the pores between large particles, and according to model it can continue to the molecular level (Kaye 1993). Because of that the number of particles of certain diameter is numbered instead of particle mass used before, and than described by the power function, called the fractal particle size distribution:

$$N(d \geq d_i) = K\left(\frac{1}{d_i}\right)^f \tag{3.3}$$

$N(d \geq d_i)$ determines the number of particles equal or greater than diameter of d_i. K is the proportionality constant. The representation of the equation in a logarithmic plot is a straight line with the slope f, which is the fractal dimension of the sand. Analysis has been made on a great number (97) of different sand types and described with nine different parameters (d_{90}, d_{50}, d_{40}, d_{10}, sorting coefficient – σ, fractal dimension of the finer sand fraction – $f1$, fractal dimension of the coarser sand fraction – $f2$, interception between the two straight lines – $Int1$, mass percentage of particles larger than $Int1$ – $Int2$). Because of the difference in the particle size distribution, the range of acceptable slot widths for each sand type have been determined, and the attempt to select a screen that will fit into this range for all investigated sand types has been done. The four slot widths have been determined. The largest slot size where severe plugging was frequently observed (d_{--}) and the smallest slot size (d_{++}) where continuous production did occur have been considered as extreme that should not be exceeded. Also the smallest slot size where no plugging was observed (d_{-}) and the largest slot size where sand production did not occur (d_{+}), have been determined as the lower and upper limits for an ideal screen design. Finally the amount of produced sand and sand production mode, permeability ratio and skin factor, and particle size distribution of produced sand have been recorded. The results have shown that any of used sand type is suitable for sand control by screen completion, but it is essential to bring well on stream slowly to lower the risk of plugging the screen. Using the defined methodology one can extend the selection for any formation sand, to define safe interval of screen slot widths where plugging and sand production will not occur.

The introduction of variety of premium mesh-type screens with irregular surfaces makes application of developed guidelines problematic (Fig. 3.13). They represent a more complex flow path for produced fluid, the cross section for flow path through these filter media is not known and must be determined through testing procedure. Regardless the way of weaving – Dutch or Hollander (Weatherford 2003) the aperture sizes of the waves can be measured and calibrated (Rideal et al. 2003). The fact is that all expendable sand screens fall within ±5% of the quoted aperture size.

3.2.3.1 Sand Retention Tests

The selection of stand alone screens is basically done by the use of sand-retention tests. Two tests have been used in industry: (1) prepack (sandpack) and (2) slurry test. With the prepack test, flow of high concentrated suspension of formation sand

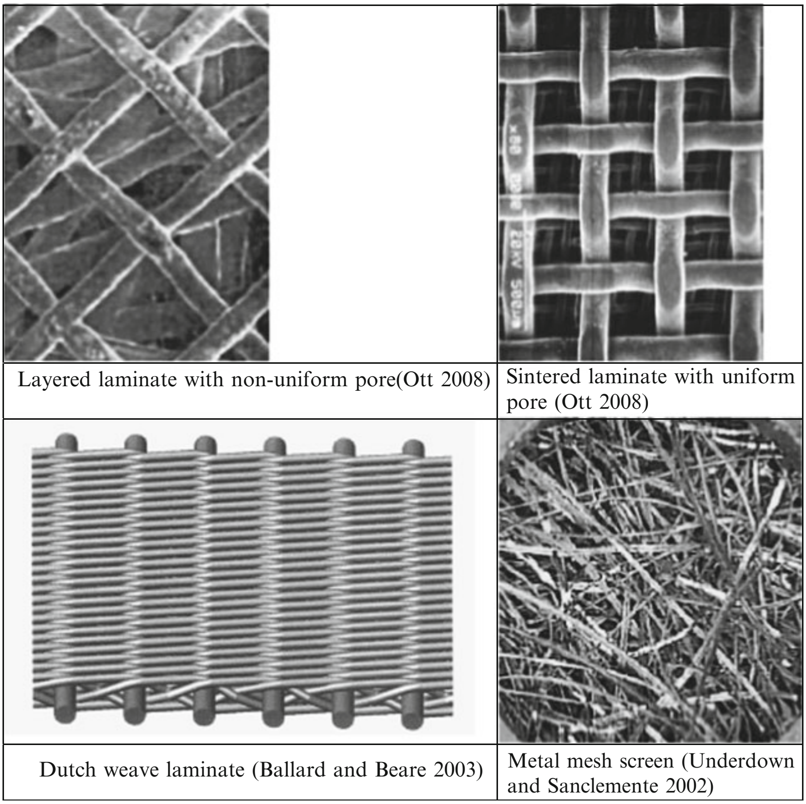


Fig. 3.13 Display of different premium screen weaving

in a viscous fluid is used to form a sandpack on the screen. When such sandpack is formed, clean carrier fluid is pressurized through the sandpack and screen at a given differential pressure. The solids that pass through such screen/deposit layer are gathered, injected fluid volume and pressure drop measured and recorded. Total amount of produced solids is measured and solids retention performance of the screen evaluated. Two possibilities of screen positioning are possible. The first is down position, when sandpack is forming on top of screen. The second is screen up position and the sandpack is lifted toward the screen. This up-flow test is more challenging for the screens, with greater chance to be plugged, especially of premium mesh-type screens.

During the slurry test, a fixed low-concentration of sand slurry (less than 1% by volume) is pumped toward the screen with determined differential pressure (flow rate). Such tests are more widely used (Underdown et al. 1999; Gillespie et al. 2000; Ballard and Beare 2003; Mathiasen et al. 2007). The testing equipment schematics used in Ballard and Beare (2003) testing is drawn in Fig. 3.14.

Through sand slurry test, sand wetted with methanol and dispersed in viscosified water is positioned in vessel and pumped and mixed with water. Entering the test

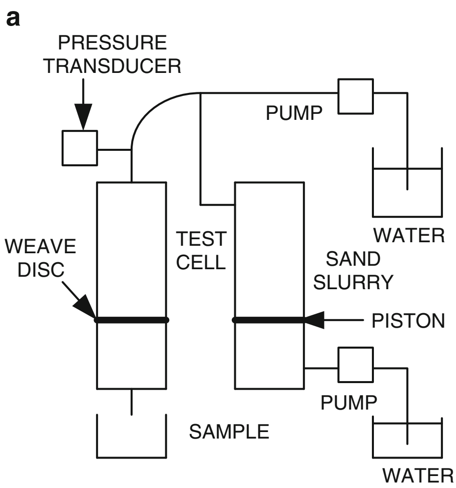


Fig. 3.14 Sand slurry test experimental set up (**a**) and sandpack test set up (**b**)

cell and flowing through the weave disc it produces pressure that is recorded. The sand produced through the screen is weighted and plotted against the registered pressure change.

The basis of the sandpack test is the test cell with the poured weighted amount of the dry sand, which is stressed and compressed with the spring over the second weave disc on top of the sandpack. Than methanol is injected through the sandpack and effluent collected. Sand recovered is dried and weighted. Each test is repeated with two flow rates. At the end the permeability of the sandpack is determined. The result can be expressed in the fact that weave screen sizing can be done using the d_5 or d_{10} equivalent to weave aperture that for such purpose must be known.

As the premium screens have gained wider acceptance a method of evaluating such screens on the basis of the relative plugging tendency and the amount of solids that will pass through was developed. The method is known as screen efficiency (SE) test (Underdown et al. 2001) and is based on measuring the pressure buildup and the amount of solids that will pass through the screen in the controlled time when solids-laden fluid is circulated at a constant flow rate. For the presentation of the results so called SE plots are used. They represent the normalized relationship of the performance factor ($performance\ factor = T_p/A_p$; where T_p is the time for the pressure profile to reach 0.6895 MPa and A_p is total area under the curve of the pressure profile) and the sand-control factor ($sand\text{-}control\ factor = 1/A_g$; where A_g is total area under the gravimetric profile). Their results show that screen plugging is a function of flux (amount of sand entering the screen per volume and unit time). Such tests have been conducted on the new generation of stainless steel mesh screen (Underdown and Sanclemente 2002) and the combination of different screens and gravel pack. The overall statement was that the combination of any of tested screen and gravel pack provides the best sand control. The value of proposed criterion has been proved in selection of sand control systems for small oilfields with poor quality unconsolidated formations (Regulacion et al. 2011). The selection is primary based on economics, because gravel packs are too expensive for such fields. So the methodology of selection was based on two processes: (1) particle size distribution and, retention-plugging testing of different screen types. Being the only option, the lower cost method using screens can be used even with a high percentage of fines content. Also the mesh screens were dominant over the wire wrapped screens in all tested particle ratings (as much as 12 times in plugging resistance and solids retention capacity). The authors have stressed the significant difference in effective open flow area between two screen types to be a major factor in screen performance.

Complex experimental work with a variety of sands (very fine, uniform and non-uniform) and screens (premium grade to standard wire wrapped) (Gillespie et al. 2000) has shown that the bridges of sand over screen openings can be achieved with sand grain of size 1/6 to 1/2 the opening size with some change based on the sand concentration. The pressure build up is controlled through the time and is the sum of pressure drop across the screen and pressure drop across the cake. The ratio of a wire wrapped screen opening must be below twice the d_{50} size of the tested sand. For premium screens, effective retention of fine particles is possible up to 2.5 times the d_{50} of tested sand. The limitation is according to sand uniformity coefficient that should be below 6.0.

The first evaluation method that has determined the amount of solids produced through the screen to be less than 0.6 $kg{\cdot}m^{-2}$ of screen inflow area (Hodge et al. 2002).

On the basis of previous investigations, performance master curves for individual screens on the basis of screen-opening pore size and the effective particle size (the ratio of the median sand-grain size to the uniformity coefficient; d_{50}/UC) (Constein and Skidmore 2006) were constructed. Also the retained screen permeability ($\geq$50%), size (d_{10}) of the produced solids ($\leq$50 μm) and produced solids ($\leq$0.6 $kg{\cdot}m^{-2}$) of total sand production over the screen inflow area were recommended.

The new analysis of common selection criteria (Chanpura et al. 2010) for standalone screens and gravel packing states, that they are too restrictive. The ratio of screen opening/d_{10} being below 1.0 was acceptable for the criterion of less than 0.6 $kg{\cdot}m^{-2}$ of total sand production over the screen inflow area.

Because the experiments with their limitations gave substantially different results, depending on test conduction and interpretation, the attempt is done (Mondal et al. 2010) to use numerical simulations. The simulation of screen behavior in contact with granular sand pack was done on the basis of size distribution and the mass of the produced solids through the test. The effect of friction coefficient, pressure gradient and ratio of screen opening to sand size, on the mechanism of natural bridges forming have been used. They have proved that friction and shear forces (fluid flow) are necessary to form stable bridges. The slot width to particle diameter ratio appears as the critical parameter that affects the number of particles produced. The bridging is facilitated when higher fluid velocities and lower pressure gradients are present.

3.2.3.2 Screen or Slotted Liners Erosion

The main wearing problem with installed screens and slotted liners is the erosion. The main cause of erosion failure is the production rate accompanied with the amount and hardness of the carrying particles. So the erosion is the function of sand carrying capacity of the fluid that is flowing through the screen or slotted liner. To evaluate the risk of the erosion, so called "C – factor" is used (API 1991). It was basically intended for use when selecting erosional velocity flowlines, production manifolds and lines transporting gas and liquid. The loss of wall thickness or basic material is determined to be due the process of erosion combined with corrosion. Loss of material is accelerated by the fluid velocity, presence of hard particles (sand) and contamination with aggressive gasses. Without other information of fluid properties, the velocity of the fluid flow above which the erosion may occur is determined using the following equation:

$$C = v_p \cdot \rho_m^{0.5} \tag{3.4}$$

The data correspond to the "C – factor" (empirical constant) obtained when the slurry or fluid velocity v_p is defined in (ft/s) and mixture density ρ_m in ($\text{lbs}_\text{m}/\text{ft}^3$). For the situations of perforations, screens and slotted liners, the data available (Keck et al. 2005) show that erosion failure occur below a C – factor of 60. That is at the time the maximum safe operating limit for cased-hole and sand control completions. These guidelines also suggest that the limitation should be lowered to the C – factor value of 30, if the quality of the sand control completion is not known. To be consistent with international system of units (SI) the use of (m/s) dimensions for flow velocity and (kg/m^3) for slurry or fluid density, leads to the "C – factor" of 73.2 (or for practical purposes 36.6) that means the use of the multiplier of 1.22.

When analyzing risk of sand control failures to the pick fluid velocities some data can be used from literature review. One has determined the annular pack instability for the velocities over 1.16 m/s (Penberthy and Cope 1980). Wong et al. (2003) have determined the maximum flow velocity to destabilize the annular pack should be up to 3.048 m/s. They have also established that the maximum slurry velocity to erode the screen should be used with a limitation of 0.3048 m/s.

The acceptable range of drawdown for specific sand control completion (Tiffin et al. 2003) lies between the rates that result with safe wells, and those that represent too high a risk. Safe operating of the wells with the middle rates can be assured with: (1) the review of completion quality (top quality is needed), (2) detection of produced amount of sand (use of sand detectors), and downhole gauge to determine pressure changes (possible flow change).

3.2.4 Gravel Packs

Gravel packing is the most widely used method of controlling sand production today. The best effect of the method is realized in initial completions. It can be

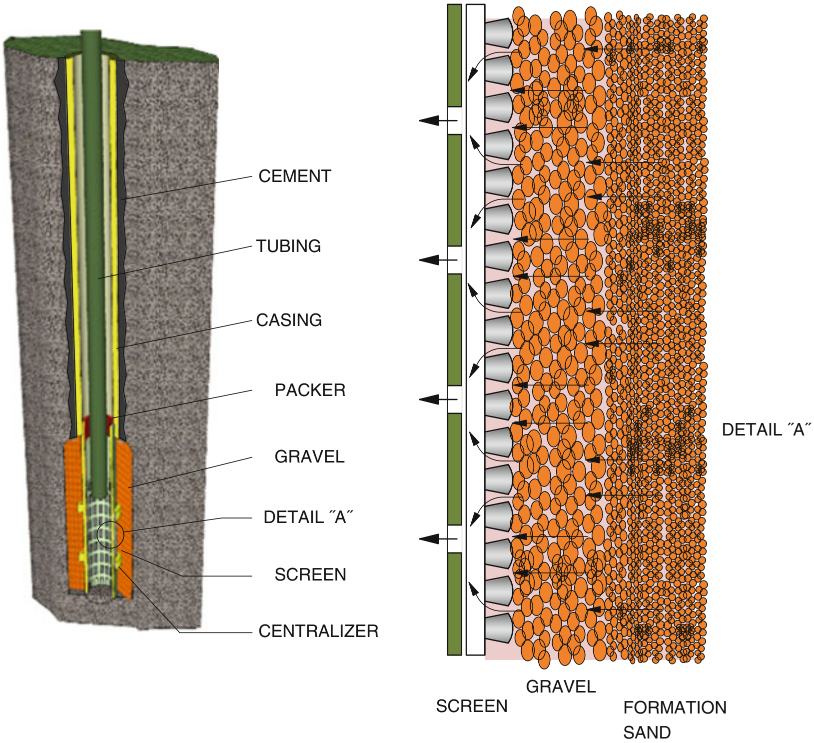


Fig. 3.15 Screen or slotted liner and gravel set in open and under-reamed hole

performed as openhole and under-reamed completion (Fig. 3.15) or in cased hole completion treatment (Fig. 3.16). Also the old wells that produce sand can be good candidates for such treatment. In such systems a pressure pack of graded sand can be placed out beyond the casing with the effect of re-stress and stabilize the formation.

Completion installations needed to apply such techniques should ensure safe treatment execution concerning the treatment pressures induced during the operation, temperature profiles downhole and presence of sour gases like H_2S or CO_2. Proper tools and accessories material selection is crucial to successful operation performance (material grade, sour gas resistivity). Pressure and temperature changes are very important from the tubular resistivity and length change point of view. They can cause occurrence of ballooning, piston, buckling, and thermal effects. Any significant change in pressure and temperature reflects on significant change of tubular length. Well deviation, treatment fluid selection, and completion fluid type are also matters of concern.

Unlike the unconsolidated formations, usually not completed without casing the reservoir section, open hole sand control can be applied in case of consolidated formation moderately prone to sand production. Usually, open hole sand control completions are used where there is only one zone to treat, but multiple zone

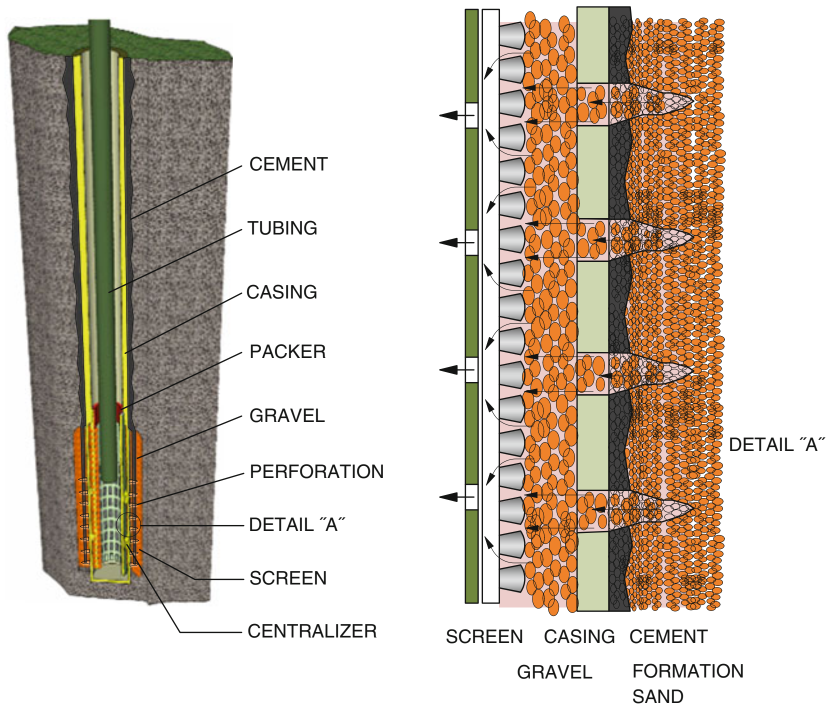


Fig. 3.16 Screen and gravel set in perforated casing

treatment is not excluded either. A major attention here should be assigned to wellbore stability and formation damage, as the word itself says the reservoir is open to different fluid invasion and other mechanical, physical impairment. Gravel packing includes installation of special equipment designed for different environments able to withstand the highest pressures and temperatures, and treating the zone(s) with suspended proppant slurry simultaneously pumped through tubing to fill formation/screen annulus.

The main purpose of such treatment is good sand filtering zone allocated between the wellbore wall and screen or slotted liner. Those way sand grains are left behind the screen or slotted liner allowing for sand free fluid production. Openhole systems like slotted liners, standalone screens and common gravel pack installations are used. A wide array of different accessories and downhole tools is also applied. A typical gravel pack placement procedure across the slotted liner is done by pumping the proppant laden slurry down the annulus. Gravel pack forms across the reamed reservoir while the pumping fluid enters the liner, through the wash pipe and up the hole.

As one of the oldest problems in the oilfield, sand production is a result of hydrocarbons production from unconsolidated formations which have very weak grain-to-grain bonds. Not all produced sand particles are *load bearing solids*. Some of them are *fine solids* produced with formation fluids. They are always produced

(Allen and Roberts 1978). Load bearing solids are the ones that make problems and together with fine solids plug all the flowing paths. To prevent equipment damage from formation particles erosion and production decline a unique sand control technique called gravel pack is used. It happens to be very well known and worldwide used. As one of the most important hydrocarbon production considerations, fluid flow area differs in case of open or cased hole completions. It is far greater in openhole completion because of no existing cemented casing across the reservoir so the flow area is not limited to perforation number and diameter (cased hole completions).

Generally, in combination with properly packed gravel around the screen section, openhole completions offer a higher productivity index comparing to cased hole systems. Gravel packed openhole completions provide a filtering media consisting of packed proppant used when the reservoir is unconsolidated with potentially mealy formation sand.

Gravel pack in tandem with screen keeps formation sand trapped inside the packed zone or behind the screen interface. That approach is very successful in gaining a sand free production fluid inflow. Completion wise, what differentiates gravel pack from standalone completions is a service tool assembly use utilized for running the assembly and pumping fluid crossing from tubing to screen/wellbore annulus and back from the screen assembly interior to the casing/tubing annulus above the production. Like with standalone openhole completions, inflatable and swelling packers play an important role in zonal isolation issues sealing and separating more then two zones enabling hydrocarbon production only from desired zone with the help of interval control devices (ICDs).

Very often, openhole reservoir section is reamed with under-reamer. It means that the wellbore diameter is enlarged to some extent. Thereby, a larger sand filtering area is introduced with better chances for stopping sand and thus greater productivity. On the other hand, under-reaming can cause additional formation damage if not executed correctly. Quality gelled fluids with proper additives assist in under-reaming open hole without additional fluid loss.

In general cased hole sand control completions (Fig. 3.16) are used to control medium to extremely unconsolidated formations (reservoirs). So they are almost always firstly cased with production casing because of the loose sand which is able to plug, erode or do some other damage to downhole equipment. By casing the production interval is more stabilized and clean area is acquired. Debris management is put under control to a certain level by stopping it behind the casing.

When installing standalone or gravel packed screens first concern and requirement is a clean well free of formation sand. Without casing in place this would be very hard to achieve across unconsolidated formation.

Although gravel packing is possible to perform in openhole as well, cased hole gravel packing is more frequent and reliable, but with smaller flowing area (flowing area equals to sum of perforation tunnels cross areas). Unfortunately, that suggests greater pressure losses.

Standalone screens in cased hole can be installed the same way like in open hole but without the need of inflatable or swelling packers capable of following the openhole wellbore wall contours.

Gravel packing in cased hole involves two basic techniques – water packing and slurry packing (viscous fluids involved). When treating either way special concern should be a treatment pressure which is not allowed to go above the fracture initiation pressure. In fact, a certain safety pressure margin below the fracturing pressure is always included. Treatment pumping deliberately above the fracture initiation pressure is considered a combined treatment consisting of hydraulic fracturing and gravel packing (frac-and-pack method).

Tools and accessories used in cased hole gravel packing are very similar to the ones in open hole gravel packing. Unlike openhole operations, cased hole gravel packing allows several zones to be treated one at a time starting from the lowermost. Such completing operations require the utmost concern, knowledge and experience in designing and executing. Gravel pack sometimes traps perforating residual materials in place without chance for cleaning it out, especially if the perforation operation is done over balance. Residuals influence the perforation permeability negatively and impacts well productivity. Screen less installations do not have such problems as the cleaning trip is done easily with coiled tubing.

Gravel packing inside cased hole implies bigger expenses at the beginning, as the production casing is run and cemented, plus perforation tunnels have to be made to accomplish connection between the reservoir and the wellbore. But, in the end, well life is prolonged due to better selectivity and flexibility, and thus better hydrocarbon recovery achieved.

Regardless the method it is essential to size the gravel properly, use clean completion fluid, optimal downhole equipment including screens and properly place the gravel. The placement of the gravel and flowing characteristics depend on perforating procedures, placement and sizing of perforations. Special consideration should be taken when selecting carrier fluid according the cleaning and mixing procedures.

3.2.4.1 Gravel Selection

The use of screens or slotted liners without gravel has suffered from wear down of production equipment and had impact on higher production costs. Such problems have been realized and investigated for a long time. Starting with several crucial works (Coberly and Wagner 1938; Tausch and Corley 1958), three problems have been considered: (1) selection of properly sized gravel to hold the formation sand in place, (2) defining the method of proper placing of the gravel, and (3) selection of the liner or screen openings to hold the selected gravel. It has been realized that the selection of the proper sizing and quality of the gravel must be studied. In ideal situation when imagine gravel pack as spheres of the same size, two possible patterns of arrangement arise. That are hexagonal packing (Fig. 3.17a) and cubical

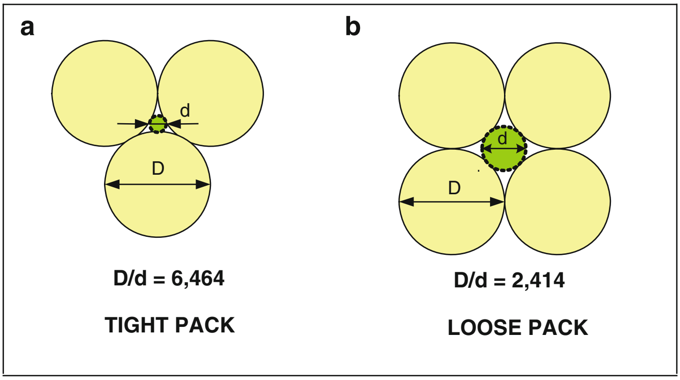


Fig. 3.17 Possible grain arrangements: (**a**) hexagonal packing; (**b**) cubic packing

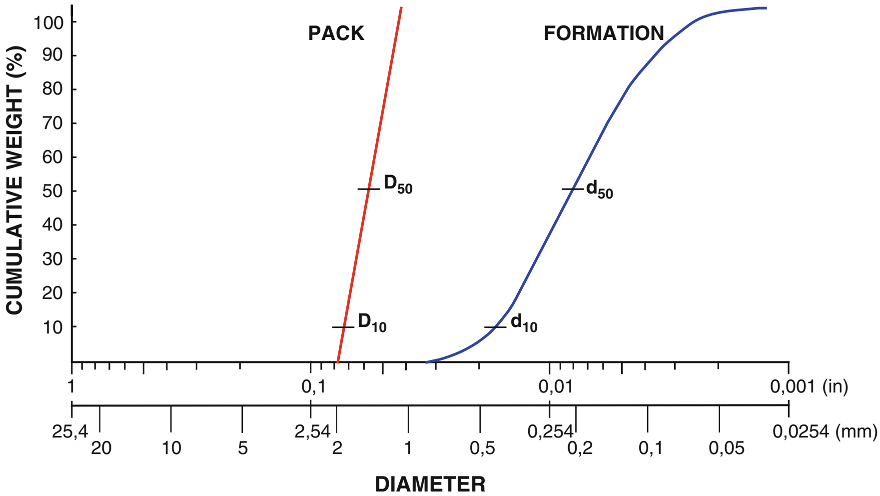


Fig. 3.18 Formation and pack sand size relations

packing (Fig. 3.17b). The testing showed that hexagonal arrangement is predominant on horizontal and vertical direction.

In selecting the gravel first consideration is the determination of size range and distribution of particle size. Some more factors also affect the quality of the gravel. Those are angularity, shape, strength and solubility. The sands are characterized by diameters corresponding to a given cumulative weight percentile (Fig. 3.18) such as D_{10} for the pack sand diameter at the 10% point on the cumulative weight percent distribution curve and d_{50} for the formation sand diameter at the 50% point. For sizing gravel pack sand d_{50} is an effective parameter, and d_{10} for screen opening specifications.

The use of 10 percentile points can be misleading, because different formations can have the same 10 percentile point size but the fine grain size and amount can vary a lot.

A variety of methods have been proposed, starting with one proposed by Coberly and Wagner (1938). It was based on the largest 10-percentile point and was valid for uniform sands. Their design rule was, $D_{10} < 10\text{–}13d_{10}$. The main shortcoming of the selection method was that it always results with gravel size too large to prevent invasion of formation fines. Much more that also causes the permeability impairment regardless the formation sand uniformity. In the attempt to reduce fines invasion in the gravel pack Hill (1941) has reduced the sizing multiplier at the same percentile point to 8. Next was the method (Buzarde et al. 1982) that has specified pack to formation sand diameter ratios at the 50-percentile and 90-percentile points. He specifies that D_{10} should be at least $3D_{90}$ for appropriate breadth of pack size range. He also proposed two more criteria; $D_{50} \leq 8d_{50}$ and $D_{90} \leq 12d_{90}$. The criteria with proposed relation of $D_{85} < 4d_{45}$ (Stein 1969) was acceptable only for formations with uniform particle size. Because of errors done in formation sampling that were the reason for poor gravel size selection the first recommendations against mixing of samples and use of bailing samples appear (Maly and Krueger 1971). They also stated that the finest producing sand in the completion is the critical one when designing sand control.

To describe grain size distribution three characteristics are frequently used:

1. Median, the diameter at the 50% point on the curve, d_{50}.
2. Sorting coefficient (SC) is the square root of the diameters of the 25% and 75% points:

$$SC = \sqrt{\frac{d_{25}}{d_{75}}} \tag{3.5}$$

3. Uniformity coefficient (UC) expresses the distribution uniformity by the ratio of the diameter at the 40% point to the diameter at the 90% point:

$$UC = \frac{d_{40}}{d_{90}} \tag{3.6}$$

Perfectly uniform sample would have a sorting and uniformity coefficient of 1.0.

The concept of sizing the gravel using design points selected on uniformity (Schwartz 1969) has helped in reducing the probability of fines invasion. It stresses out the need that the gravel be uniform (it allows only small difference in smallest and largest particle sizes), with uniformity coefficient of approximately 1.5. Proposed rules included the following: $D_{10} = 6d_{10}$ for uniform sands ($UC < 3$); $D_{40} = 6d_{40}$ for non-uniform sands ($5 < UC < 10$); and $D_{70} = 6d_{70}$ for extremely non-uniform sands ($UC > 10$). He has also discussed the fluid velocity impact on gravel stating that velocity affects the gravel in two ways. Primarily the sand-carrying capability varies directly with the velocity of the fluid and much more increase of fluid velocity tends to destroy pack stability. To consider the pack as the stable one it should control sand under the anticipated flow conditions. The "critical velocity" of the fluid through the pack; the point when bridging mechanism is disintegrated for a water-well is one that reaches 0.09 m·s^{-1}, but as the optimum design figure the velocity of 0.03 m·s^{-1} was empirically established.

Through that time gravel packs were only about to percent successful (Manooti 1968). Because of that laboratory flow studies have been conducted (Saucier 1972). They show that at that time adopted particle bridging criteria are satisfactory only for uniform flow but are unsatisfactory for disturbed flow conditions. It also appears that formation sand invasion into a gravel pack is minimized and effective pack permeability maximized for pack-to-formation median grain size ratios of less than 6. The roundness and sphericity of the pack grains are also proposed, because they enable maximum pack permeability. It was also shown that pressure drop across perforations can be controlled with larger diameter and greater density of perforations. Also the perforation tunnel must be packed with gravel. Figure 3.19 shows results of the tests that recommends that the diameter of the median size of the gravel pack D_{50} be five to six times the diameter of the median size in the formation sand d_{50}: $D_{50} = 5\text{–}6d_{50}$. Where flow velocity is obtained by dividing cumulative production with 50% of open area. The pack must be tight because gravel to formation sand ratio is based on a tight pack. Pack thickness should be at least 76.2 mm. In practice it was determined that a pack thickness greater than 203.2 mm (8 in.) cannot be properly developed, and that due the tool capabilities limit of thickness is up to 127.0 mm.

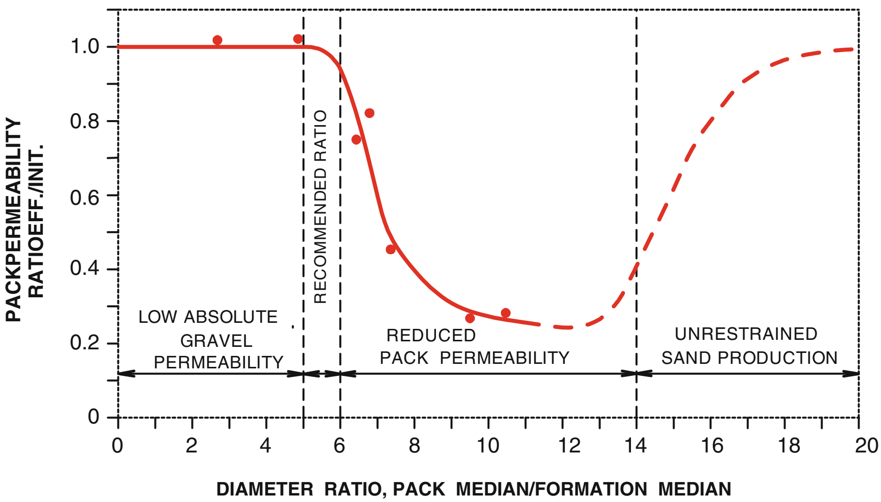
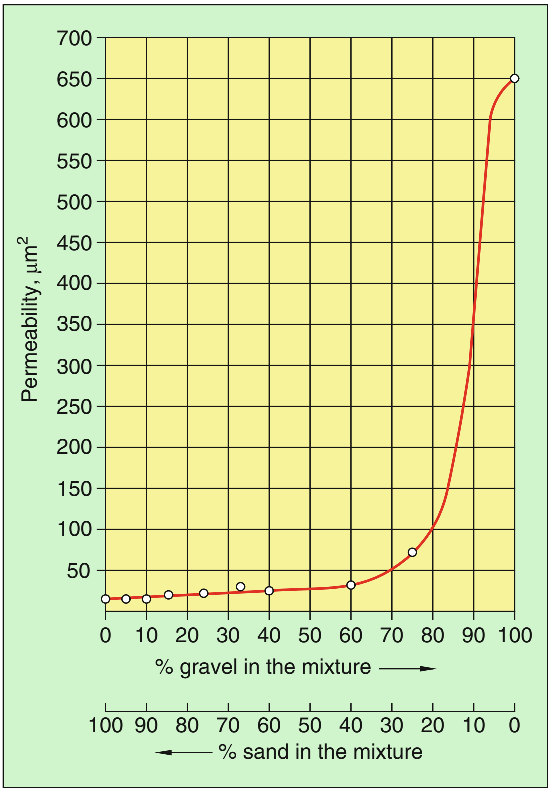


Fig. 3.19 Effect of the ratio of medium gravel size to medium sand size on gravel pack permeability (Saucier 1972)

Fig. 3.20 Permeability dependence on gravel to pack sand mixing and arrangement (Sparlin and Copeland 1972)



Mixing of high permeable gravel with formation sand (Fig. 3.20) that is possible during placement of gravel, reduces the permeability and is not recommended or allowed.

Effective gravel packs require that the formation sand be retained at the outer edge of the pack. When they are mixed it reduces the permeability of the gravel pack resulting in low productivity. The analysis of the productivity of cased-hole and open-hole gravel packs (Penberthy and Cope 1980) has shown that cased-hole gravel packs result in well productivities far below the productivity of open-hole packs. It also stresses out the importance of pre-packing the formation and perforations with gravel. It was also visible that some small amounts of formation fines are produced continuously through the gravel pack under high-rate conditions. Because of that gravel pack should be designed to allow the production of the fine particles.

Another proposed criteria (Tiffin et al. 1998) based on field experience and experiments conducted with core samples from different sand formations has been in use to the present moment. It has introduced two new parameters: sorting parameter (d_{10}/d_{95}) and mass fraction of fines (particles smaller than 44 μm). When all values are under the proposed thresholds, the risk of damage or malfunction will be very low. The proposed ratios are as follows:

1. Standalone screens can be used if $d_{10}/d_{95} < 10$.
2. Wire-wrapped screens should be used if $d_{10}/d_{95} < 10$ and $d_{40}/d_{90} < 3$ and fines $<2\%$ by weight.
3. Woven mesh screens should be used if $d_{10}/d_{95} < 10$ and $d_{40}/d_{90} < 5$ and fines $<5\%$ by weight.
4. Large gravel (seven to eight times the median) should be used if $d_{10}/d_{95} < 20$ and $d_{40}/d_{90} < 5$ and fines $<5\%$ by weight.
5. When $d_{10}/d_{95} < 20$ and $d_{40}/d_{90} < 5$ and fines $<10\%$ by weight it is advisable to use a combination of larger gravel and fine-passing screen.
6. With large amount of fines ($d_{10}/d_{95} < 20$ and $d_{40}/d_{90} < 5$ and fines $>10\%$ by weight) there is a need for enlarging wellbore (that means to move the gravel/formation sand interface away from the wellbore).

The definition of fines (Byrne et al. 2010) was not clear according to different approach from geological and engineering view. From the engineering view the 44 μm size corresponds to the 325 mesh screen, the finest commonly used screen in sieve analysis. Also from reservoir point of view, fines are those parts of the rock that can move through the pores of the intact rock. Not only the moving fines but also the fines from failed and re-sorted formations should be considered. They can plug pore throats, screen openings and gravel packs, bat also be collected in pipelines and surface equipment causing the erosion and corrosion wearing. One more problem that should be solved is connected with resorting of fines with other materials in the screen/openhole annulus with tendency to impact in screen plugging and higher skins. The sources of mobile fines are those rocks that have loose or soluble bonds (kaolinite). Such mobile particles have the diameter of 3–10 μm. If they can pas through the pore throats of the formation matrix in range of 10–30 μm they will also pass through ideally packed gravel with openings in the range of more than 100 μm. The mobilization of fines is usually connected with high fluid velocities or with water breakthrough. It also shows the importance of gradually bean a well up. Much more the fines can be responsible for plugging the matrix, gravel pore space, screens or fill the facilities. So the modified and enhanced sand control selection process is based on representative rock sample analysis. To determine the presence of fines Laser Particle Size Analysis (LPSA) is used along with sieve analysis. Also the optical and Scanning Electron Microscopy (SEM) should be used, and if any indication of fines, they should be determined also by X-ray Diffraction (XRD) to determine the quantity of clay fraction. The last analysis would help to determine the behavior of fines. The sand retention test should be done with consideration on bean up rate that could affect the test results. When there is a need for selectivity, oriented or selective perforation should be considered. Zonal isolation is applied mostly in cased and perforated holes. Isolation sleeves, inflow control devices and external packers (inflatable or swell packers) are also used. All of that is used to increase the contact between the well and the formation, and to control the flux inflow rate. That will reduce the fluid velocity and lower the chance to move fines.

3.2.4.2 Gravel Pack Sand Quality

To perform unimpaired gravel-pack it is essential to use high-quality gravel-pack sand. The gravel characteristics that can cause low permeability include: excessive fines content, excessive oversized grain content, angular or flat grains, low quartz content and high amount of polycrystalline grains. Thin-sections and photomicrographs can be used to determinate the presence of fractures and grain multi-crystallinity, roundness and sphericity. The use of normal light will enable determination of fractures under the microscope. Using the polarized light the mono- or multi-crystallinity of the grains is visible. The procedure of sampling and testing sand used in sand control is determined in the API RP 58 (API 1995). It specifies the sampling of the material on the basic source with minimum one sample for each 4,540 kg of material. At the job site minimum one sample should be obtained for each 908 kg of material. Through the sieve analysis using proposed sieves, the amount of fines and oversized grains are determined. In no case they should exceed 2%, when minimum 96% of sample should be within designated size range. Angular grains with sharp edges can cause problems, because such edges can be broken and become fines during shipping, handling or pumping. Also gravel with flat grains results in reduced pack permeability. So the roundness and sphericity are determined according the visual comparation (Krumbein and Pettijohn 1938) with the chart shown in Fig. 3.21.

Only the gravels with roundness and sphericity factors of 0.6 and greater should be used in sand control.

High quality gravels contain a minimum of 98% quartz. Being a very hard mineral it is resistant to crushing and attack by acids. The next demand is according

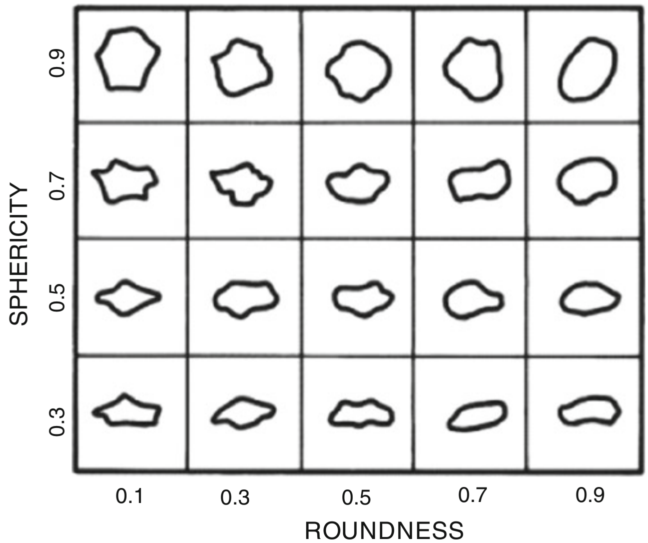


Fig. 3.21 Chart for visual estimates of sphericity and roundness

to solubility. It states that acid-soluble materials in the gravel pack should not exceed 1%. The composition of 12% by weight hydrochloric acid (*HCl*) and 3% by weight hydrofluoric acid (*HF*) is used under standard test conditions.

Minimal fines generation under a crush load is one of the main requirements due the generation of fines. Two measurements can be conducted. Measurement of the individual gravel grain strength and measurement of the bulk crush resistance. The first measures the strength of individual grain. The second is conducted using the pressure cell to crush the bulk. The pressure of 13.8 MPa is applied for 2 min. The amount of fines generated through the crushing test depends on sand size. It can vary from 8% for sand size from 2.38 to 1.19 mm (8/16 mesh), to 4% for sand size from 1.68 to 0.84 mm (12/20 mesh), and 2% for sand size from 1.19 to 0.60 mm (16/30 mesh); 0.84 to 0.42 (20/40 mesh); 0.60 to 0.20 (30/50 mesh) and 0.42 to 0.25 mm (40/60 mesh). It has been stated (Zwolle and Davies 1983) that fines generation increases with increasing percentage of multicrystallinity and decreases with increasing roundness.

The effective permeability to oil can be secured by circulating water with a 1% of water-wetting surfactant through the dry gravel to ensure water-wet gravel.

3.3 Gravel Pack Methods

Gravel packs can be set in openhole using reverse circulating method (Fig. 3.22) and crossover gravel pack or inside gun perforated casing using wash down method, crossover method (Fig. 3.23) or reverse circulating method. Development of small diameter tools and the use of coiled tubing enable so called through-tubing gravel packing.

Openhole gravel packing completed with screens are set when maximum production is required when formation sand is too fine to be stopped by a conventional screen. Layers with several separated strata and especially salt-water disposal wells and fresh water source wells (large diameter wells) are often completed in this manner.

The casing must be set just above the producing interval and cemented (Fig. 3.22a). Than the hole must be underreamed to at least 152.4–304.8 mm larger diameter than is the diameter of the casing. To clean the underreamed interval reverse circulation with gel water is used. Also a caliper log should always be run to approve the actual diameter of the underreamed interval. The screen and liner are made up with a reverse circulating shoe on the bottom of the gravel control equipment (Fig. 3.22b). Screen is centralized with the spring type centralizers in the openhole, and weld-on centralizers inside casing. Blank pipes are used to define distances between wire wrapped screen and telltale screen. To position the equipment hook-up nipple, stuffing box, landing joint, clutch joint and wash pipe with opening nipple are also used. All that is run on the work string and wire wrapped screen is set opposite the producing zone. The valve in the reverse circulating shoe must be kept open all the time until the shoe is covered with gravel. The gravel is pumped down the casing with carrying fluid (Fig. 3.22c). The gravel will fill the

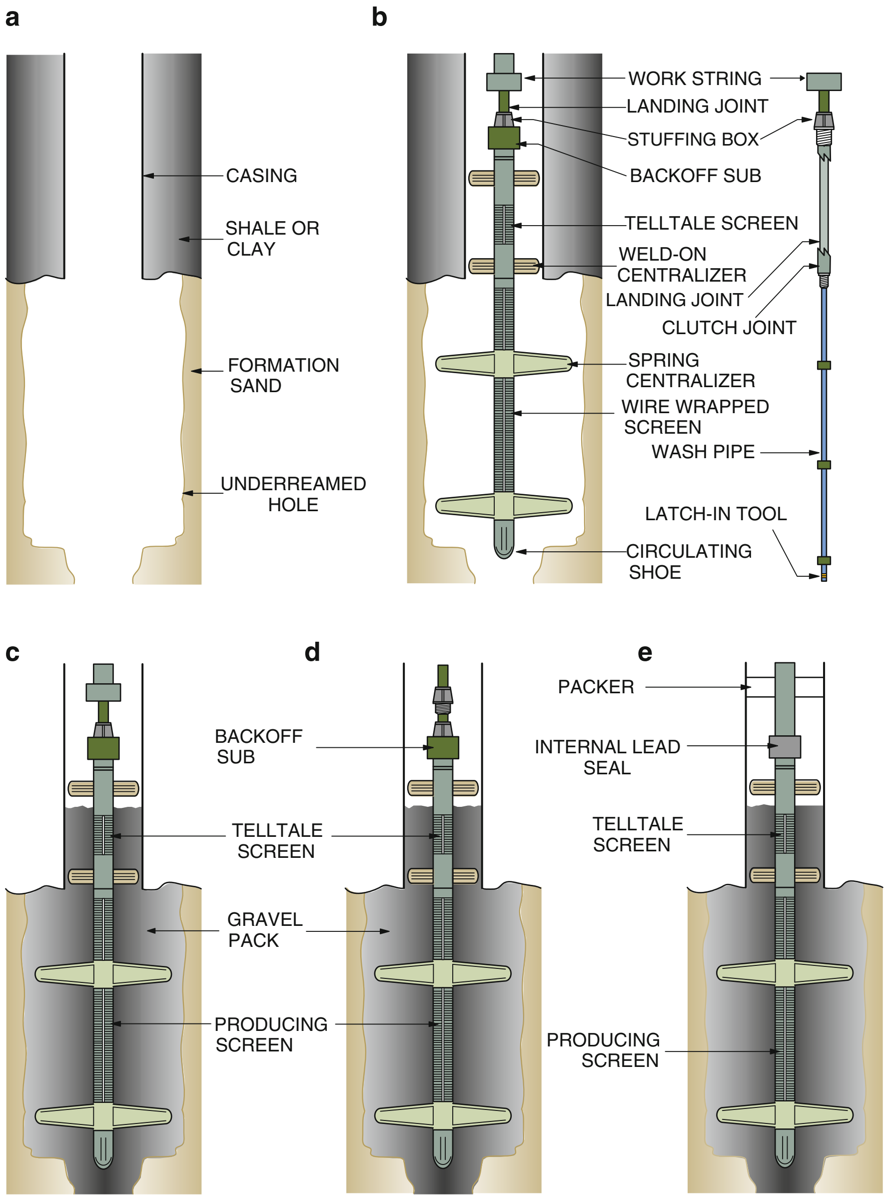


Fig. 3.22 Gravel pack placement in the openhole using reverse circulation method: (**a**) Underreamed hole, (**b**) Screen positioning with running tools, (**c**) Gravel pumping, (**d**) Releasing and retrieving of running tools, (**e**) Packer and internal seal installation

open hole and bridge around the slots of the screen without entering the screen. Fluid alone returns through the wash pipe. Reaching tell tale screen fluid passes through it and continue to travel down between the screen and the wash pipe to the

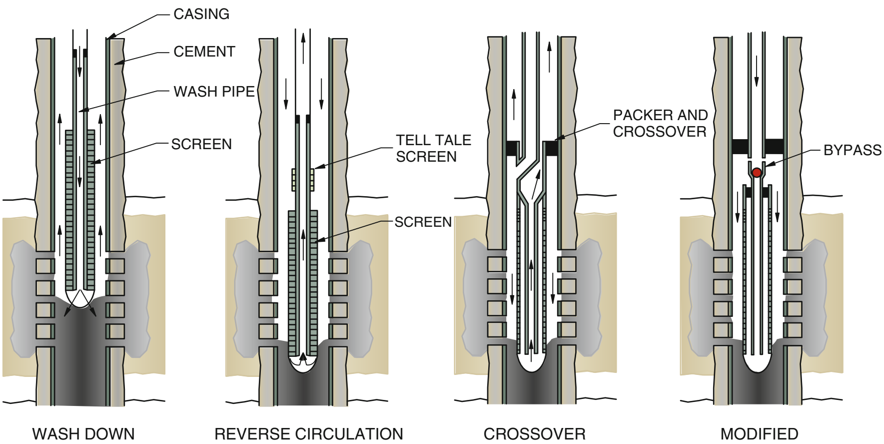


Fig. 3.23 Common types of inside gravel packing

bottom of the screen. Than the fluid flows out the screen openings, continues to the shoe and once more flows up through the wash pipe. That helps in creating a slight pressure buildup which packs the gravel as it deposits around the screen. The process continues until the gravel covers the tell tale screen, when the pressure buildup will be visible on the gauge at the surface. The work string is than raised until the clutch joint engages the stationary clutch in the bottom of the stuffing box (Fig. 3.22d). Rotation of the engaged clutch will disengage the stuffing box from the hook-up nipple. Now wash pipe can be pulled out the screens and blank pipes up to the surface and out the hole. If some kind of packer is needed (Fig. 3.22e), it can be run with an internal lead seal (or some other) on the bottom of the packer, and the packer set.

To achieve the most efficient gravel pack, according to production, it is essential that the gravel fills the annual space and perforations. When those spaces are completely filled with gravel, pressure loss will be minimal. Also the screen or the liner must be completely covered with the gravel to prevent sand production and erosion. The amount of reserve gravel must be enough to allow for setting.

The use of screens set in gun perforated casing combined with gravel packs is the most common method today for controlling sand in oil wells. Gravel is selected to control formation sand and screen is designed to control the gravel. Inside gravel packs are used when it is necessary to exclude gas, water or shale problems. The recommendations for realization of improved productivity in inside gravel pack installations are: (1) removing of perforation debris, (2) use of proper and clean completion fluid, (3) use of smaller gravel sizes, and (4) assure squeeze packing of the perforations (Penberthy Jr and Echols 1993). The job can be executed as a single-stage or two-stage process. Two-stage gravel packing operation first packs the perforations, and than circulates the gravel into the screen-casing annulus. Wash down method of inside gravel packing is shown in Fig. 3.24.

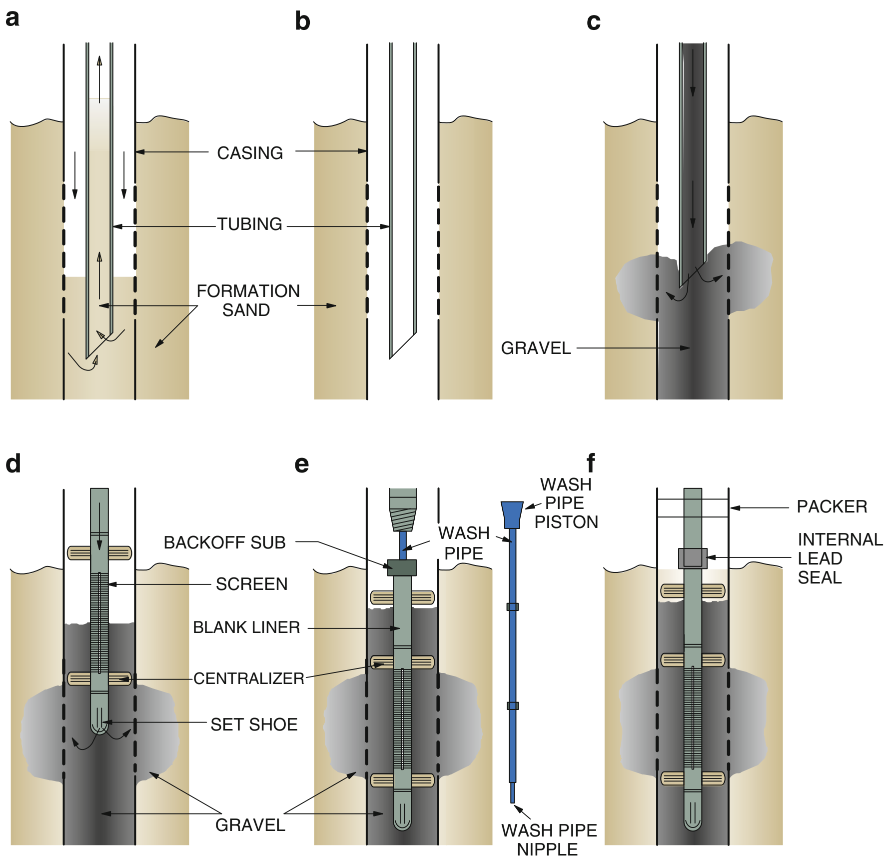


Fig. 3.24 Wash down method for gravel pack setting inside gun perforated casing: (**a**) Formation sand removal, (**b**) Clearance determination, (**c**) Through tubing gravel pumping, (**d**) Gravel wash-out to desired depth, (**e**) Gravel compaction by pressuring up, (**f**) Packer and internal seal installation

Open-end tubing is run to the bottom of the hole and reverse circulated to remove formation sand from inside the well bore. The process must been continued until returned fluid is clean of sand and debris (Fig. 3.24a). Running the tubing again through the washed interval will recheck that the formation sand is entirely cleaned from the hole (Fig. 3.24b). Running the open end tubing down hole opposite the bottom perforations (Fig. 3.24c) will enable to pump gravel down through the tubing. Closing the blowout preventer and opening flow line when a batch of gravel reaches bottom will enable to pressure up and force the gravel out the perforations. The tubing is moved up and down with braden-head or low pressure squeeze until the gravel is above the perforations. The turbo-jet or standard set shoe are made up at the bottom of the screen joint, centralizers, blank liner, back-off sub, releasing joint, wash pipe and piston (Fig. 3.24d). The tubing with the sand control assembly is run in the wellbore to tag the top of the gravel. Starting pump and reaching desired pressure will enable to wash-out the gravel and place the screen to desired depth. When the shoe reaches desired depth, the pump is shut off and the gravel is allowed to fall around the screen. Waiting for determined time will enable gravel settling. To compact the gravel, annulus between screen and casing can be pressured (Fig. 3.24e). The wash pipe can now be disengaged and pulled out from the hole. If there is a need for isolating device, packer with internal lead seal on the bottom or some other kind of sealing equipment can be used, according to expected pressure differential in the well (Fig. 3.24f).

The method that uses crossover tool is the common in use today, because it keeps sand-laden fluid within work string for better control and to prevent pack fluid contamination in the annulus.

Some gravel pack installations allow for casing perforation and gravel packing one at a time only with one completion assembly. This perforate-and-gravel-pack procedure consists of regular gravel packing tools and assemblies run with perforating guns situated on the assembly bottom. Completion run and set procedure begins with setting the packer at the desired depth to fire the guns, which is done by dropping the firing bar down the tubing. Upon firing, guns are released to the bottom. Releasing the packer takes place afterwards to lower the gravel pack screen assembly across the perforations. After setting the packer again, normal gravel packing procedure can begin with squeezing the perforations and packing screen/casing annulus with main treatment.

Dual zone gravel pack completion is only one set of numerous options available to complete the well. This particular installation allows the isolation of the lower zone from all gravel packing operations and pressures taking place on the upper zone thereby minimizing fluid loss and potential formation damage. After the lower zone gravel packing operation has been performed and the service tool assembly pulled out from the well, a packer plug is set in the packer to protect the lower zone. The upper zone is then perforated underbalanced to obtain clean, large-diameter perforation tunnels. The packer plug is retrieved and upper zone is ready for gravel packing.

Running a snap-latch seal assembly ensures that the production seals are properly positioned in the lower packer. Seal assembly features low snap-in force and straight pull snap-out release (snap-out force can be used as a strain indication that the seal assembly is properly landed in the lower packer).

Upper zone gravel packing assembly is then run in, the packer set and the service tool released and positioned for gravel packing. The bottom end of washpipe includes a perforated pup joint and seal assembly. The seal assembly seals off in a polished bore inside the snap latch. In this position all return fluid must flow through the screen and the lower zone is isolated from any pressure applied to the upper zone.

In reverse circulating position gravel packing ports are above the packer. With the lower seals of the service tool assembly sealing in the packer bore and the reversing ball sealing on its ball seat, the formation is isolated from reversing pressures preventing fluid loss to the formation. Fluid circulated down the annulus enters the gravel pack ports reversing any excess gravel out of the workstring. Dual packer is used in these applications as well. It is run and set in the final producing position.

Dual packers are mechanical devices able to seal the annulus from tubing interior and carry out the hydrocarbon production from two zones through two separate tubing production strings. There are different types of dual packers but most of them are hydraulically activated and unseated by applying pressure through one of the strings. When calculating packer forces and stresses each string should be taken into account separately. Three string or four string packers use is very rare but still useful if knowledgably applied with other “smart well” tools and accessories. Both zones can now be produced independently, the lower zone through the long string and the upper zone through the short string.

Three or four zones can be gravel packed the similar way but much more complex tools and accessories should be used which worsens the operation efficacy.

3.3.1 Through-Tubing Sand Control

Problems connected to sand control in production wells usually result because of wrong primary completion design. Marginal wells that are producing sand and have poor reserves do not support the cost of a major work overhaul program. In such cases it is not economical to re-complete the well by the use of a classical tubing and packer system or standard completion rigs. Some remedial work include sand bailing with wire line (which is obsolete, time consuming, and suitable only for small volumes) and sand washing with coiled tubing. Unfortunately such alternatives are only a temporary solution and do not solve the problem of sand production.

When coiled tubing was first introduced as a new technology, major advances were made with clean/wash out operations, to assist with the sand clean out from the wells. They have covered about 32% of coiled tubing jobs at that time (Engel and Mackey 2001). Research and analysis dealing with the causes of failed runs found that 44% of failures were due to bad or poor planning, 33% was due the unknown or harsh conditions of the well, 22% were equipment failures and 1% was due to human error. The same analysis covered about 1,200 runs over the 23 month period and showed an overall success of 82% by addressing these issues. The database has suggested that there are three fundamental causes of failure as shown in Fig. 3.25. Clean out (sand wash out), along with tools and drilling are among them. Detailed planning and training has been identified as the primary solution of these problems.

Since that period, a lot has changed. Today there are a number of products and services available to the industry which increases the success of through-tubing sand control. The true sand control methods than can be applied may be divided into two categories: (1) chemical methods (which coat and bond formation sand in place with resins or other bonding chemicals) and (2) mechanical methods (which include small diameter gravel pack screens). The method selected and the job design depends on the mechanical configuration of the wellbore. Also worth considering are: the casing size, minimum restriction in the wellbore, type and location of the landing nipples, packer setting depth, tail pipe below the packer, the length of

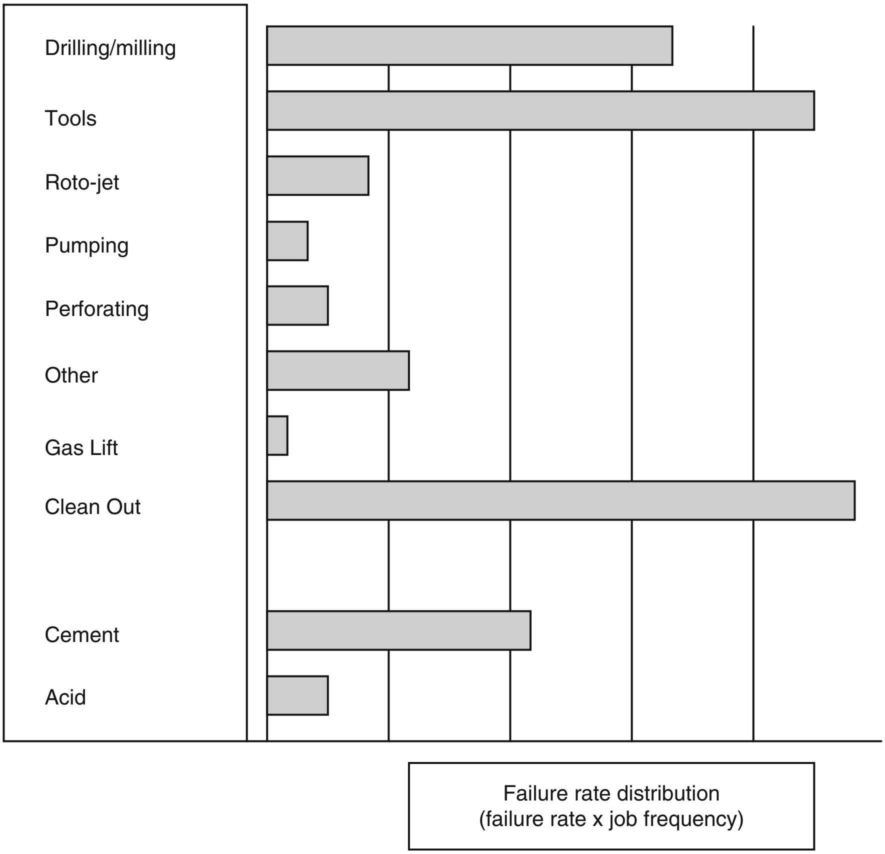


Fig. 3.25 Comparison between failure rates and job frequency

interval to be recompleted, location of interval in relation to production tubing, length of the rat hole below interval, formation type and type of well production (oil or gas and volume of water).

When sand clogging occurs in tubing and casing, the well is shut down for some time before any decision on remedial maintenance is made to get the well back to production. The first step in the process is to clean the tubing and casing and remove any settled sand from them.

Chemical methods of sand control always employ chemicals and resins that are injected into poorly consolidated formations to help bond the grains. Two common methods are used: (1) consolidation of sand with resins using brines as a placement fluid and (2) packing of formations with resin coated sands. Both methods utilize catalyst that can be internal or external. The optimum use of such methods is achieved under the following conditions: (1) treating relatively long intervals, (2) for wells with small internal diameters, (3) when static bottom hole temperatures are between 15°C and 204°C, and (4) when fluids/brines with density below 1,390 kg·m^{-3} are used.

Most often, water compatible furan resins are used for near wellbore sand consolidation. In average, a wellbore radius of over 1 m can be consolidated in such ways (Murphey et al. 1974).

After cleaning the wellbore, saltwater is pumped into the formation to help prepare the sand surface for the chemical reaction that will enable the resin to absorb the sand. The resin is than pumped and flows by the saltwater spacer to separate the acid and resin and to remove excess resin from the pore spaces. This is achieved by flushing it further into the formation. Acid is then pumped into the formation to catalyse the resin. Finally a specific amount of brine is injected into the formation to enhance the displacement of the catalyst. Uniform displacement of the resin in the formation can be achieved by mixing nitrogen with the injection fluids. After the resin hardens, a solid sand filter is formed with permeability in the range of 85–90% of the original mix.

The idea here is to replace formation sand with packing's of higher permeability. Ottawa sand (quartz, roundness, sphericity) 0.8382–0.4318 (20/40 mesh) or 0.4318–0.0254 (40/60 mesh) is used and batch-mixed with the resin and carrier fluid. Both internal and external catalyst can be used, but the use of external catalysed system will allow placement of the pack in the formation and wash out the excess sand from the wellbore prior to the acid being pumped to set the resin. When an internal catalyst is used, fewer steps for pack placement are required and the treatment continues until sand out occurs in the perforations. That means that the column of coated sand is formed in the well and that must be removed after the resin cures.

This practice has showed high rates of failure and the limited life associated with the chemical consolidation processes, so therefore the mechanical methods are highly recommended.

The most widely used is the mechanical method because of the following advantages: (a) rig less completion – the low cost method for return a well to production; (b) the methods are simple and effective; and (c) with the use of an optimal fluid system it has minimal impact on formation damage (Lee et al. 2001). Thru-tubing screens can be widely used. Figure 3.26 shows the possible uses.

Two methods for gravel placement are often in use:

1. A conventional circulating pack that utilize gravel concentrations of 2.4–4.8 $kg{\cdot}m^{-3}$ with a circulation rate of 0.32–0.64 $m^3{\cdot}min^{-1}$. The carrier fluid can be sea water or brine whose viscosity can be increased with starch; and
2. A slurry pack that enables circulation of high concentrations of gravel (up to 180 $kg{\cdot}m^{-3}$) by the use of a viscous carrier fluid. Due to the high concentrations of the gravel, the placement time is significantly reduced.

The recommended carrier fluid should have a viscosity of at least $50{\cdot}10^{-3}$ Pa·s (at a shear rate of 170 s^{-1}) at down hole conditions in order to keep the gravel in suspension. Also it should break-back within a time of approximately 1 h after the gravel placement, so that loss of "screen out" can be detected and extra gravel added if required.

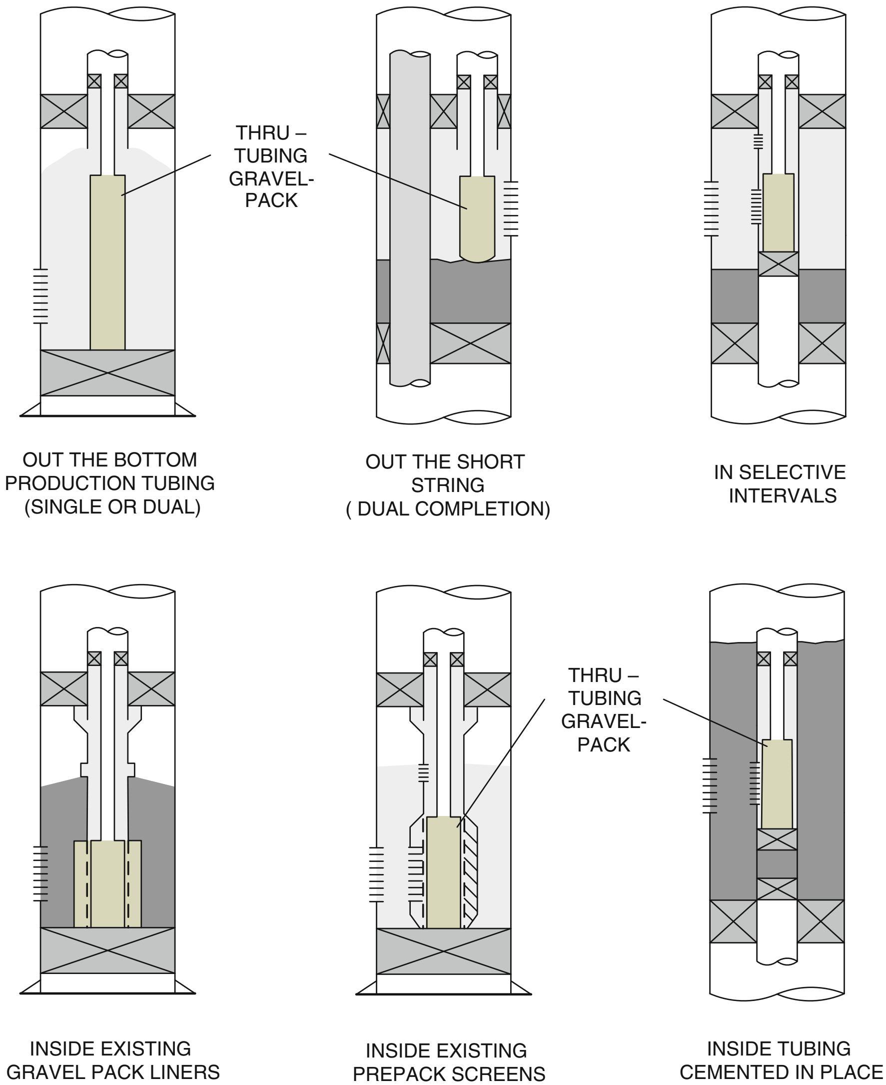


Fig. 3.26 Possible through-tubing gravel pack installations

The development of high viscous cross-linked polymer fluids indicated that the fluid is capable of transporting heavy concentrations of gravel, and that there is also a good bleed-off or fluid loss once the slurry reaches the formation. There is a need of laboratory testing to define: (1) the fall rate of gravel vs. temperature, (2) the possibility of formation core damage, (3) changes due to the pressure packing, and (4) change of viscosity with temperature change.

The imperative is that a high concentration of gravel can be pumped through the coiled tubing with desired volume, without excessive friction forces. At the same time no pipe plugging should occur and the slow fall rate of gravel in the carrying fluid must ensure that the gravel will not settle above the screen before the pack is obtained. The change of gravel fall rate in such fluids with respect to temperature change, for different gravel sizes is shown in Fig. 3.27.

There can also be a great difference in gravel fall rate in servicing fluids with different polymers, their concentrations (Fig. 3.28) and the change of viscosity vs. temperature (Matanović and Krištafor 1994).

The possibility of formation core damage can also be determined using consolidated core samples. Test core samples should be cleaned, dried and saturated with a 2% Potassium Chloride (*KCl*) solution, and initial permeability determined. The viscous polymer fluid is then injected into the core sample placed in the testing cell. The cell must be sealed for 2 h and heated to 65.5°C (150°F). At the end of this test, the core is flushed with 2% KCl and the retained permeability determined.

The optimal gravel-pack is obtained when there is a tight uniform pack, with grain-to-grain contact, and with tight packing achieved. That is possible if after the screen-out occurs, the additional pressure is applied against a formation.

The next stage is to develop and produce tools to enable gravel placement with the coiled tubing. A typical installation consists of the following from the base up: bull plug, screen, centralizer, blank spacer pipe, receptacle sub, receptacle nipple, pack-off assembly, and a slip stop hold-down device. The detail is shown in Fig. 3.29.

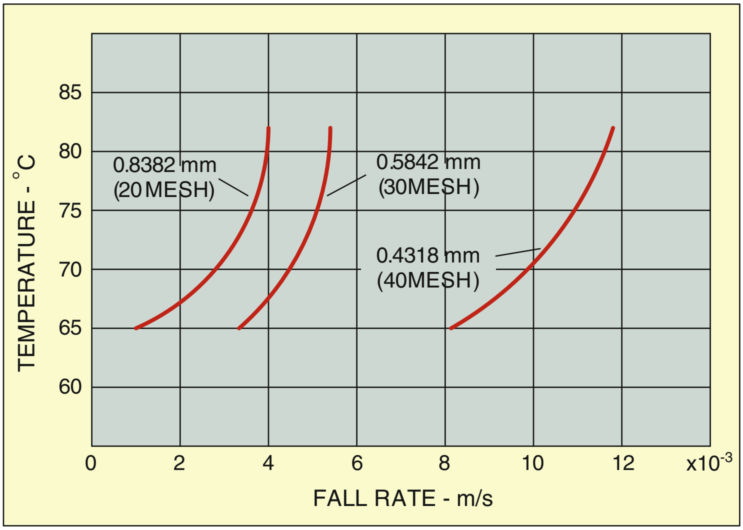


Fig. 3.27 Gravel fall rate according to temperature change (Shurtz et al. 1975)

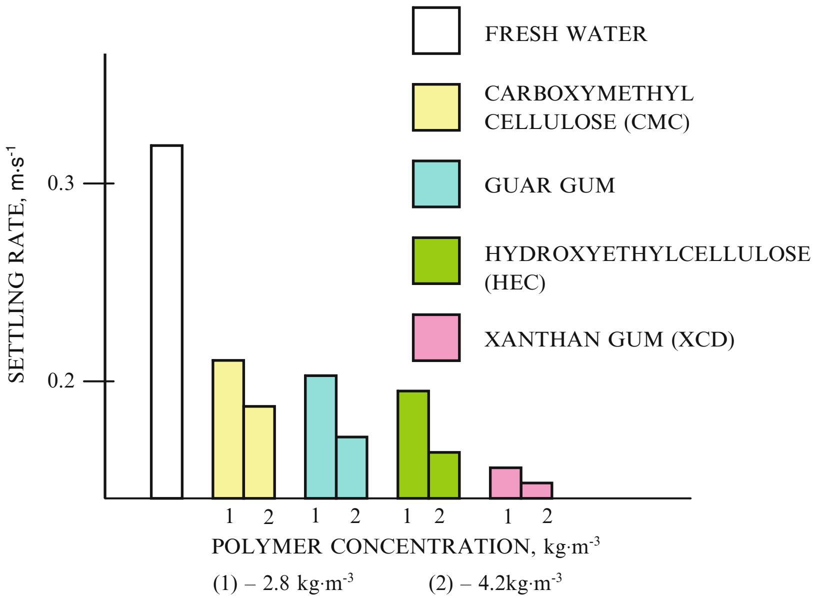


Fig. 3.28 Comparison of sand settling rates of a 0.8382–0.4318 mm (20–40 mesh) sand

The bull plug serves as a guide when installing gravel pack equipment and prevents rock particles or fluids entering inside the equipment.

The screen length is determined by the length of the production interval. The openings of the screen are predetermined through formation sand screen analysis and from theoretical and field experience. Experience has shown that it is a good practice to reduce the screen openings to some extent to ensure that there will be no formation sand entering through the openings. This will prevent any formation sand settling inside the production string. The reason for that is in fact that no washing out of settled materials is possible inside such small diameters.

The spacer pipe length is determined in relation to existing mechanical hook-up of production string, and can vary in length from 1.8 to 18 m.

The receptacle sub is run on the top of the blank pipe above the screen. Its novel design enables it to fulfill four primary functions:

1. Connecting the blank pipe with the screw and centralization itself inside the tubing by the use of centralizers, so that the receptacle nipple can be installed.
2. Enables the attachment of running tool (the running tool slips over the receptacle sub and is attached with shear pins), and releasing by pushing down after the screen is positioned in the well.
3. Support of the liner plug that is placed in the polish bore section of the receptacle sub prior to running the gravel-pack assembly (the liner plug seals off the spacer pipe and the screen to prevent the gravel entering inside the screen during the gravel placement and is removed in a clean-out trip).

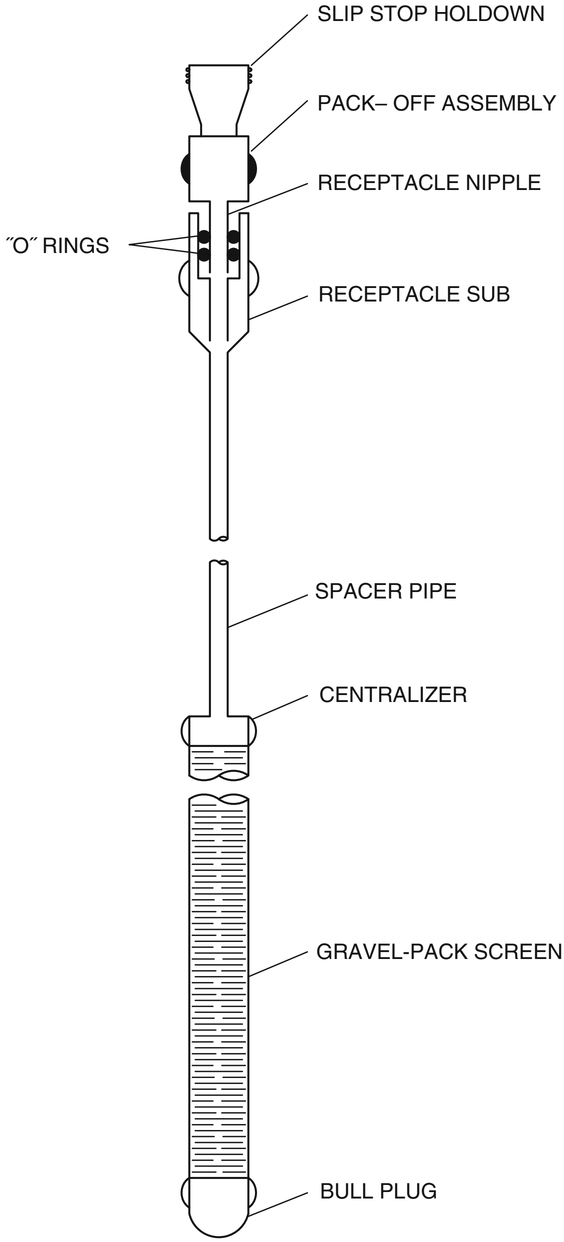


Fig. 3.29 Gravel pack equipment in use with coiled tubing

4. Support of the liner receptacle nipple that is run on the bottom of a wire line pack-off assembly (the nipple is screwed into the polished bore of the receptacle sub and seals off the annular space of the spacer pipe so the formation fluid will pass through the screen and not around the blank pipe.

The pack-off assembly seals off the annular space around the gravel-pack assembly and is set on the top of the receptacle sub.

The slip stop hold-down keeps pack-off assembly from unseating.

Several methods of gravel pack placement that are commonly used include:

– Pack off method – this uses a thru-tubing gravel pack screen with a blank spacer pipe and pack off seal assembly and can be placed inside the casing or existing gravel pack screen and spaced up and packed off inside the production tubing.
– Dual screen method – this uses two screens separated by blank pipe when production enters the lower screen and exits through the upper screen.
– Wash-down method – this uses a pre-pack bed where the gravel pack screen is "washed" into place and packed off.
– Reverse circulation method – this provides a means runoff running the screen into position across the perforations and then pumping the gravel and fluid slurry down the tubing.

Regardless the implemented method, there are several procedures that are common for all of them:

- When re-perforating it is essential to use clean fluid without hard particles, compatible with formation rocks and fluids.
- Establish stable fluid flow in the formation direction.
- Pre-pack the formation with gravel.
- Determine maximum diameter of the screen according to the inner diameter of the production tubing joints.
- Calculate the screen length so that it covers at last 1.5 m above and bellow the covered perforated interval.
- The length of the well below the perforations is of importance. If it is excessive it is recommended to use an anchor packer 3–5 m below the perforations. When using coiled tubing it is also possible to place gravel through the coiled tubing and fill that area. If whole volume of the gravel is placed with coiled tubing it is also possible to place the plug using a wireline. Alternatively it is also possible to use inflatable packers. That can be activated inside the production tubing or inside the casing, especially in situations when it is desired to divide the upper and lower perforations (if the lower perforations are producing water).
- To make sure that there is no restriction in the well bore it is recommended to make a gauge run and only than to run the screen.

In pack off method the through screen assembly is attached to a blank pipe that must be of sufficient length to enable screen placement to be made on the defined depth. In this case, blank pipe extends inside the production tubing to be packed off. The bottom hole assembly configuration may vary depending on availability, but generally it consists of a bull plug at the bottom, screen, and blank pipe with centralizers and a running tool. Possible configuration (Fig. 3.30) is run with one overshot running tool, and the shear pin must be sheared to disconnect the coiled tubing from the retrievable receptacle plug, that is pinned in the seal receptacle. After rigging up the coiled tubing, a few meters above the screen assembly the sand

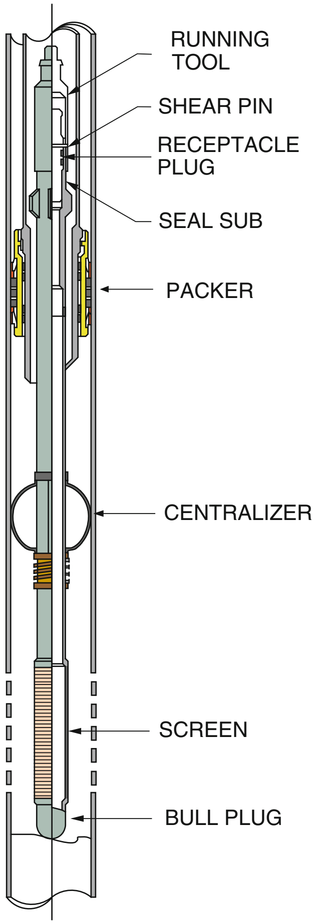


Fig. 3.30 Down-hole equipment for the pack off method

slurry should be pumped. After screen out occurs it is necessary to extract the excessive amount of the sand from the hole. After the gravel settling the pack off assembly and anchor are positioned and activated, that terminates the process.

When the length of the opened interval between the perforations and the end of the tubing is high (more than 30 m) slurry must be pumped through the coiled tubing to reach the upper screen, left to settle down and if possible be put in production by the use of nitrogen through the same coiled tubing string. Because the blank pipe is not extended into the production tubing smaller drawdown pressures occurs. Also pack off, seals and seal receptacles are omitted which reduces material costs and lower labor costs. The production path is from perforations to the lower screen up the blank pipe to the upper screen to the open casing area.

The essence of the wash-down method is to spot the gravel across the perforations on the casing, and than wash down all gravel to the desired depth. Selected gravel is pressurized in the perforations and than reversed to the point where the bottom of the assembly set shoe is positioned. Then the well bore is filled with new gravel to about 15 m above the top perforation. Screen and liner are assembled with turbo jet shoe, and spring type centralizers are placed at a distance of about every 18 m in the casing. The screen used must overlap the perforated interval at a minimum of 1.5 m at each end, and the blank liner must extend into the production tubing at least 6–9 m. It also consists of a wash pipe with the seating nipple on the

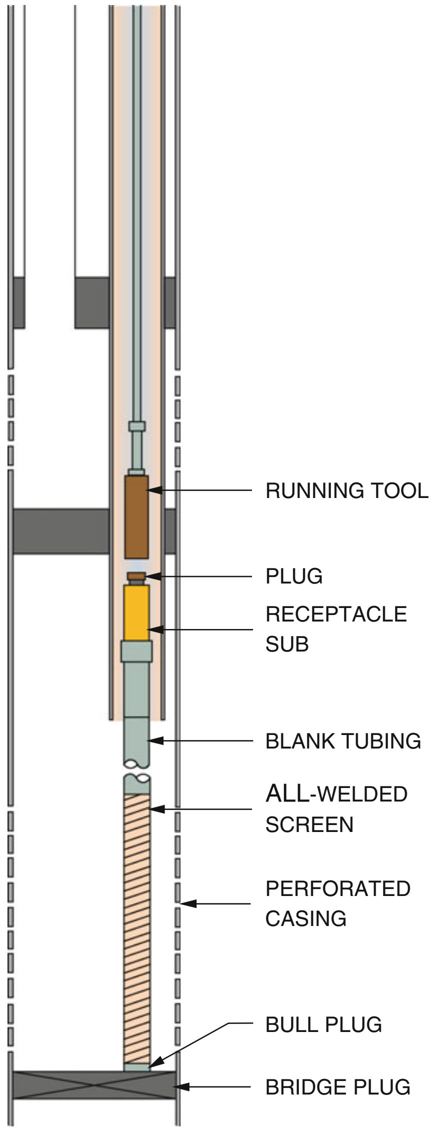


Fig. 3.31 Reverse circulation method for dual completion

bottom and a wash pipe piston on the top positioned about 0.5 m above the releasing tool with the left-hand thread. The completed assembly is than lowered into the well to tag the top of the gravel. After rising for a while the pump is started and the equipment washed down through the gravel. When the bottom is reached it is necessary to wait a while so that gravel settles down; some pressure on the annulus is recommended. The wash pipe must be freed on the left hand thread (possible by a hydraulic disconnect). A wire line packer is than set on top of the backoff sub.

The reverse circulation method is often in use in dual completions. The aim is to run the screen and liner over the length of perforations and the gravel polymer slurry is than pumped down the tubing. Formation sand is washed out and perforations cleaned. The assembly is positioned across the perforations and released. The top plug prevents gravel from entering the screen. Gravel in the polymer slurry is pumped down the tubing and then the gravel is pressured-up. Excess gravel above the liner is washed out to enable the wire line unit to retrieve the plug and set the packer on top of the receptacle sub (Fig. 3.31).

Nomenclature

A_g	Total area under the gravimetric profile
A_p	Total area under the curve of the pressure profile
$C-factor$	Empirical constant for evaluation of the risk of the erosion, $Pa^{0.5}$
$d_{10;\ 40;\ 50;\ 90;\ 95}$	Diameter of formation sand particle at (10; 40; 50; 90; 95 percentile) point, mm
D	Diameter of the gravel pack sand, mm
D_i	Initial outer diameter of the pipe, m
D_f	Final (expanded) pipe outer diameter, m
f	Fractal dimension of the sand
F_s	External surface area per meter of the liner, m^2/m
K	The proportionality constant
l_e	Length of expanded slot part, m
l_s	Slot length, m
m	Number of links between slots over the pipe cross section area
$N(d \geq d_i)$	Determines the number of particles equal or greater than diameter of d_i
n_s	Number of slots per 1 m of the liner, m^{-1}
SC	Sorting coefficient
T_p	Is the time for the pressure profile to reach 0.6895 MPa
UC	Uniformity coefficient
w_e	Slot width after expansion, m
w_s	Slot width, m
α_s	Total slot area of total external surface area of the liner, m^2

References

Ali S et al (2002) Combined stimulation and sand control. Oilfield Rev Summer 14:30–47
Allen TO, Roberts AP (1978) Well completion design. In: Production operations, Part 1: Well completions, workover and stimulation, Chapter 5. Oil & Gas Consultants International, Tulsa
API RP 14 E (1991) Recommended practice for design and installation of offshore production platform piping systems, 5th edn. API, Washington, DC, 1 Oct 1991
API RP 58 (1995) Recommended practice for testing sand used in gravel packing operations, 2nd edn. API, New York
Baker Oil Tools (2002) Sand control systems. Baker Hughes, Houston
Ballard T, Beare S (2003) Media sizing for premium sand screen: Dutch twill weaves, SPE 82244. In: SPE European formation damage conference, The Hague, 13–14 May 2003
Belarby J (2009) Well completion design. Elsevier, Amsterdam
Bradley HB et al (1992) Petroleum engineering handbook. Society of Petroleum Engineers, Richardson
Buzarde LE Jr, Karl RL, Bell WT, De Priester CL (1982) Lecture Notes for: Production Operations Course 1: Well Completions, SPE of AIME, Dallas
Byrne M, Slayter A, McCurdy P (2010) Improved selection criteria for sand control – when are "fines" fines? SPE 128038. In: International symposium and exhibition on formation damage, Lafayette, 10–12 Feb 2010
Chanpura RA, Hodge RM, Andrews JS, Toffanin EP, Moen T, Parlar M (2010) A review of screen selection for standalone applications and a new methodology, SPE 127931. In: SPE international symposium and exhibition on formation damage control, Lafayette, 10–12 Feb 2010
Coberly CJ (1983) Selection of Screen Openings for Unconsolidated Sands. Drilling and Production Practice, 37–189
Coberly CJ, Wagner EM (1938) Some Considerations in the Selection and Installation of Gravel Pack for Oil Wells. Pet Technol Vol. 1, No. 3, Aug 1938
Constein V, Skidmore V (2006) Standalone screens selection using performance mastercurves, SPE 98363. In: SPE international symposium and exhibition on formation damage control, Lafayette, 15–17 Feb 2006
Coulter AW, Gurley DG (1970) How to select the correct sand control system for your well, SPE 3177. In: 41st annual California regional meeting of the SPE of AIME, Santa Barbara, 28–30 Oct 1970
DePriester CL (1964) Sand control, course materials, Chapter IV
Durrett JL, Golbin WT, Murray JW, Tighe RE (1977) Seeking a solution to sand control, SPE 6210. J Pet Technol, December 1977, Vol. 29, No. 12, 1664–1672
Engel SP, Mackey P (2001) Opportunities to improve the success rate of coiled-tubing operations, SPE 68429. In: SPE/ICoTA coiled tubing Roundtable, Houston, 7–8 Mar 2001
Gillespie G, Deem CK, Malbrel C (2000) Screen selection for sand control based on laboratory tests, SPE 64398. SPE Asia Pacific oil and gas conference and exhibition, Brisbane, 16–18 Oct 2000
Halliburton Energy Services (1994) FracPac completion services. Halliburton Energy Services, Houston
Harrison DJ, Johnson MH, Richard B (1990) Comparative study of prepacked screens, SPE 20027. In: 60th California regional meeting, Ventura, 4–6 Apr 1990
Hecker MT et al. (2010) Extending openhole gravel packing capability: initial field installation of internal shunt alternate path technology. In: SPE annual technical conference and exhibition, paper SPE 135102, Florence, Italy
Hill KE (1941) Factors affecting the use of gravel in oil wells. Drilling & Production Practice, API
Hodge RM, Burton RC, Constein VG, Skidmore V (2002) An evaluation method for screen-only and gravel-pack completions. In: SPE 73722, international symposium and exhibition on formation damage control, Lafayette, 20–21 Feb 2002

Innes G, Morgan Q, Macarthur A, Green A (2005) Next generation completion systems. In: SPE/IADC middle east drilling technology conference & exhibition, paper SPE/IADC 97281, Dubai

Kaiser TMV, Wilson S, Venning LA (2000) Inflow analysis and optimization of slotted liners (SPE 80145). In: SPE petroleum society of CIM international conference on horizontal well technology, Calgary, 6–8 Nov 2000

Kaye BH (1993) Fractal dimensions in data space; new descriptors for fine particle systems. Part Part Syst Char 4(10):191–200

Keck RG, Colbert JR, Hardham ED (2005) The application of flux-based sand control guidelines at the Na Kika deepwater fields. In: Paper SPE 95294-MS, SPE annual technical conference and exhibition, Dallas, 9–12 Oct 2005

Krumbein WC, Pettijohn FJ (1938) Manual of sedimentary petrography. Appleton-Century, New York

Lake LW, Clegg JD (2007) Petroleum engineering handbook – production operations engineering, vol IV. Society of Petroleum Engineers, Richardson

Lee CC, Darby M C, Popp TR (2001) Effective thru tubing gravel pack methods in Attaka field, SPE 72132. In: SPE Asia Pacific improved oil recovery conference, Kuala Lumpur, 8–9 Oct 2001

Li Z, Yao D, Samuel GR (2007) Modeling expandable slotted tubulars, SPE 109674. In: SPE annual technical conference and exhibition, Anaheim, 11–14 Nov 2007

Maly GP, Krueger RF (1971) Improper formation sampling leads to improper selection of gravel size. J Pet Technol, December, Vol. 23, No. 12, 1403-1408

Manooti MA (1968) Statistical analysis of recent sand control work. In: API committee on sand control, API paper 926-13-G

Markestad P, Christie O (1996) Selection of screen slot width to prevent plugging and sand production, SPE 31087. In: SPE formation damage control symposium, Lafayette, 14–15 Feb 1996

Matanović D, Krištafor Z (1994) Sand washing with coiled tubing. Nafta 45(8), Zagreb, Croatian National Committee of World Petroleum Congresses and Croatian Academy of Science and Art, Croatian National Committee of World Petroleum Congresses and Croatian Academy of Science and Art, 389–396

Metcalfe P, Whitelaw C (1999) The development of the first expandable sand screen. In: Offshore technology conference, paper OTC 11032, Houston

Mathiasen AM, Aastveit GL, Alteras E (2007) Successful installation of standalone sand screen in more than 2000 wells – the importance of screen selection process and fluid qualification, SPE 107539-MS

Mondal S, Sharma MM, Chanpura RA, Parlar M, Ayoub A (2010) Numerical simulations of screen performance in standalone screen applications for sand control, SPE 134326. In: SPE annual technical conference and exhibition, Florence, 19–22 Sept 2010

Murphey JR, Bila VJ, Totty K (1974) Sand consolidation system placed with water, SPE 5031. In: 49th annual fall meeting of the SPE of AIME, Dallas, 6–9 Oct 1974

Ott WK (2008) Selection and Design Criteria for Sand Control Screens, SPE 120505-DL, SPE Distinguished Lecture and Presentation During 2007–2008

Ott WK, Woods JD (2003) Modern sandface completion practices handbook, 1st edn. Gulf Publishing Company, Houston

Patton LD, Abbott WA (1979a) Well completion and workover: Part 2: Data requirements for completion planning. Petroleum Engineering International, May 1971

Patton LD, Abbott WA (1979b) Well completion and workover: Part 3: Selecting the best well completion. Petroleum Engineering International, June 1979

Perrin D (1999) Well completion and servicing. Institut Francais du Petrole Publications, Paris

Penberthy WL Jr, Cope BJ (1980) Design and productivity of gravel-packed completions. J Pet Technol, October, Vol. 32, No. 10, 1679–1686

Penberthy WL Jr, Echols EE (1993) Gravel placement in wells. J Pet Technol, July, 612, 613, Vol. 45, No. 7, 670–674

Regulacion R, Seno A, Bn Safiin N, Bt Nik Khansani NZS (2011) Optimized stand-alone screen design for the "J" field, Malaysia, SPE 141461. In: SPE production and operations symposium, Oklahoma City, 27–29 Mar 2011

Renpu W (2011) Advanced well completion engineering. Elsevier, Oxford

Rideal GR, Storey J, Morris TR (2003) Pore size measurement of 3-dimensional woven filters using calibration microspheres, Whitehouse Scientific website, www.whitehousescientific.com

Romero JL, Pizzarelli S, Mancini J (2002) Simultaneous stimulations and/or packing in multiple zones. Effective solutions. In: SPE annual technical conference and exhibition, paper SPE 77437, San Antonio

Saucier RJ (1972) Gravel pack design considerations, SPE 4030. In: 4th annual fall meeting SPE of AIME, San Antonio, October

Schwartz DH (1969) Successful sand control design for high rate oil and water wells. J Pet Technol, September, Vol. 21, No. 9, 1193–1198

Shurtz GC, Breiner WG, Comeaux BG (1975) New thru tubing gravel pack technique, SPE 5660. In: 50th annual fall technical conference and exhibition, Dallas, 28 Sept–1 Oct 1975

Sparlin DD, Copeland T (1972) Pressure packing with concentrated gravel slurry, SPE 4033

Stein N (1969) Sand control method using a particulate pack with external and internal particle size distribution relationships. US Patent 3,434,540

Suman GO Jr, Ellis RC, Snyder RE (1983) Sand control handbook, 2nd edn. Gulf Publishing, Houston

Tausch GH, Corley Jr. CB (1958) Sand exclusion in oil and gas wells. In: Spring meeting of the southern district division of production, Houston

Tendeka (2011) Web-based online screen manual

Tiffin DL, Kong GE, Larese RE, Britt LK (1998) New criteria for gravel and screen selection for sand control, SPE 39437. In: SPE formation damage control conference, Lafayette, 18–19 Feb 1998

Tiffin DL, King GE, Larese RE, Britt LK (2003) New criteria for gravel and screen selection for sand control, SPE 39437. In: SPE formation damage control conference, Lafayette, 18–19 Feb 2003

Underdown DR, Dickerson RC, Larese RE, Britt LK (2001) The Nominal Sand Control Screen: A Critical Evaluation of Screen Performance. In paper SPE 75326-PA, SPE Drill Compl Vol. 16, No. 4, December 2001, 252–260

Underdown DR, Dickerson RC, Vaughan W (1999) SPE 75326. Annual technical conference and exhibition, Houston, 3–6 Oct 1999

Underdown DR, Sanclemente J (2002) SPE 74394. SPE international petroleum conference and exhibition, Villahermosa, 10–12 Feb 2002

Van Buren M, Van Den Broek L (1999) Trial of an expandable sand screen to replace internal gravel packing. In: SPE/IADC middle east drilling technology conference, paper SPE/IADC 57565, Abu Dhabi

Weatherford (2003) Expendable technology: Alternative borehole liners (ABL®), overview and benefits

Wong GK, Fair PS, Bland KF, Sherwood RS (2003) Balancing Act: Gulf of Mexico sand control completions, peak rate versus risk of sand control failure, SPE 84497. In: SPE annual technical conference and exhibition, Denver, 5–8 Oct 2003

Zwolle S, Davies DR (1983) Gravel packing sand quality – a quantitative study, SPE 10660. J Pet Technol, June, Vol. 35, No. 6, 1042–1050

Chapter 4
Chemical Consolidation

Contents

Abstract When reservoir sand grains in near wellbore zone are loose and prone to production, either mechanical or chemical sand control methods are used. Chemical consolidation of sand grains appears to be very demanding, but quite effective method for sand control. To effectively apply chemicals for consolidation (resin systems are most frequently used) a great amount of field experience is required. Two types of resins are described – thermosetting and thermoplastic. Additives in service of system setting acceleration and activation, residual water removal and other, are also introduced.

Chemical consolidation treatment execution is divided in few stages – reservoir cleaning and water removal, treatment pumping and overflushing excess materials. Alternative solution to resin system pumping is resin-coated sand, incorporated in gravel packing operations with aforementioned grains coated with a thin resin layer melting and consolidating on higher temperatures.

4.1 Introduction

Formation damage in any form requires a chemical treatment to be designed and pumped for permeability impairment removal. Formation fines and sand production is one of these forms, bridging and plugging the pore throats and eroding the downhole equipment. Problem regarding sand production during hydrocarbons recovery is very

D. Matanović et al., *Sand Control in Well Construction and Operation*,
Springer Environmental Science and Engineering,
DOI 10.1007/978-3-642-25614-1_4,

well known. When it occurs production must be reduced to face it. Local near wellbore collapses may endanger many well operations. Several sand control techniques (mechanical or chemical) are applied worldwide. More costly alternatives to mechanical (standalone screens, gravel packing, frac packing) are chemical techniques, as in situ chemical consolidation of sand with agents (chemicals).

Since sanding problems appear in unconsolidated formations prone to produce sand, where grain-to-grain forces are not enough to keep the formation strength, there is an option to consolidate such formations with either of the following chemical types (Kotlar et al. 2005; Larsen et al. 2006) – (1) Polymer based chemicals (resins) or (2) Other chemicals like organosilanes and derived enzymes ($CaCO_3$ precipitation).

Organosilane chemicals technology features include oil solubility, hydrophobic nature, low bioaccumulation tendencies and high biodegradation factor while enzymes (mostly ureasa) are used for production of minerals like calcium carbonate or calcium phosphate, applied in sand consolidation.

Here, we will concentrate on polymer based sand consolidation which, basically, consists of pumping polymerized organic resins inside near wellbore zone when gravel packs do not perform well. A major idea is to consolidate sand grains together without damaging the reservoir by lessening the permeability to oil that happens due to oil wettability of resin occupying the pores. Excess resin must be displaced from pore spaces with overflush fluid (Economides 1997).

Although is hard to achieve both at the same time, operators do their best to properly consolidate mealy formations and form a mass which has a better compressive strength and to keep the reservoir pores not damaged with resin. Figure 4.1 shows the pore spaces and sand grains bonded with resin adding to its compressive strength. Section 4.3 will show how to bond these sand grains.

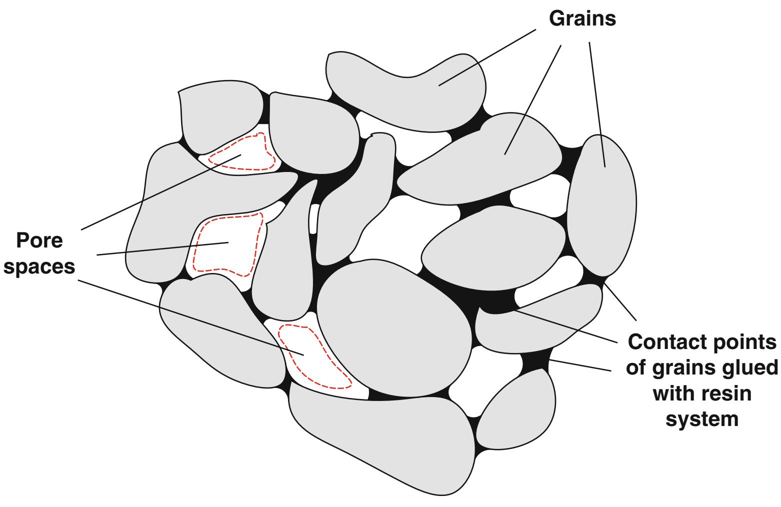


Fig. 4.1 Grains contact points after the resin consolidation treatment

4.2 Resins

In terms of chemical composition, resins are solid, hard to soft, organic non-crystalline polymers, brittle in the solid state. Molecular mass distribution of resins polymer network is very narrow. Flammable nature of resins requires an extra caution when handling and treating. In general, resins are raw materials for curable molding composition adhesives and coatings used in oil industry like in many others. There are two types of resins: *thermosetting* and *thermoplastic resins*.

4.2.1 Thermosetting Resins

When introduced to heat source, thermosetting resins change irreversibly from fusible and soluble to infusible and insoluble material through cross-linked polymer network. They have a pretty low molecular weight (<10,000).

After the curing process, that is a transformation from liquid to solid network state, polymer chains link into one molecule.

The most utilized types of thermosetting resins are:

- ***Phenol resins,***
- ***Furan resins,***
- ***Amino resins,***
- ***Epoxy resins,***
- ***Unsaturated polyester resins,***
- ***Urethane foams,***
- ***Alkyl resins.***

Basically, thermosetting resins are very stable over a wide range of temperatures, chemically inert to wellbore fluids and rocks and environmentally safe.

When thermosetting resins are cured and cross-linked, thermoset polymers are strong, hard and tough. When hot resin solidifies creating a hard mass between sand grains, it is able to withstand huge stresses.

4.2.2 Thermoplastic Resins

Unlike thermosetting resins, thermoplastic ones are reversible, meaning that by applying different pressure and temperature their physical state changes. Thermoplastic polymers consist of linked monomers of very high molecular weight (>10,000). Molecular bonds can be easily broken by heating or dissolving the matter.

Thermoplastic resins include:

- ***Polyethylene,***
- ***Polypropylene,***

- ***Polystyrene,***
- ***Polyvinyl chloride,***
- ***Furan resins.***

Furan resins can be fabricated to be thermosetting or thermoplastic.

4.2.3 Resins Curing Process

The process of curing (also known as a cross linking process) relates to resin transformation from liquid to solid state. During that process monomers link into clusters until network is created forming a mass. As clusters become bigger and bigger their movement becomes restricted. After reaching a *gelling point*, clusters move no more due to very high viscosity of the system and the friction forces generated. If the resin is not properly placed inside the near wellbore zone before reaching the gelling point, it is not possible to pump and squeeze it further on (Wasnik and Mete 2005).

There are some important requirements resins must apply (Schechter 1992):

- *The resin dynamic viscosity has to be moderately designed with values not more than 0.02 Pa·s. This will allow for good ability to pump the resin through all the restrictions without excessive pressure losses and to displace it with overflush fluid,*
- *The resin must wet formation solids to be able to bond them together, but only at certain points without over-occupying the pore spaces,*
- *When put in place, polymerized resin should have good compressive strength for sand movement prevention,*
- *Resin polymerization starting moment should be controlled with additives. Too short times may result in improper consolidation or even improper placement,*
- *Although polymerized resin is not water-wet, it should be able to tolerate long contacts with formation brines and must not be reactive with acids.*

4.3 Treatment Execution

Working with resin systems necessitates the utmost job performance supervision and experience to be able to perform the treatment safely and technically correct. Interval to be treated with resins has to be isolated from the rest of the well to ensure effective injection into the perforations, prevent loss of process fluids and resins contamination. Mostly, the treatment execution embraces up to 1.5 m thick near wellbore zone. For the successful future hydrocarbon production it is better to treat the zone which has not produced sand before the resins treatment (sand production prediction is made). Thin layers treatment ($<$6.0 m) is recommended (Schechter 1992). It is possible to treat maximum 7 m thick zone in one stage (Bellarby 2009).

Prior to treatment, perforation tunnels should be cleaned by pumping a cleansing fluid (HCl-HF conditioned acid system) to remove any unwanted particles capable of endangering the treatment process. Particles left inside the perforations will be solidified with resin after the treatment.

Appropriate workover fluids have to be used as well, and that is brine with sodium chloride (KCl) and diesel or lighter brine for placement above the treating zone (for prevention of resin system mixing with wellbore fluids).

Preflush operation's primary intention is to remove reservoir fluids (water specifically) not compatible with resin system and capable of contaminating it (see Fig. 4.2a, b). Since resin has to affix the grains, which is possible only in oil wet conditions without the residual water, the major concern here is weather the reservoir grains surface is water or oil wet.

According to that preflush fluid has to be chosen carefully depending on the resin system type used. In some cases *diesel with surfactants* is used. Other preflush systems contain *isopropyl alcohol* or *mutual solvents* like *EGMBE* (Ethylene glycol mono-butyl ether) for water removal (Brooks 1974, Smith 1969).

(a) *Before the treatment water wet conditions are met with residual water surrounding the grains*
(b) *By preflushing, mutual solvents successfully displace the residual water and maintain the permeability*

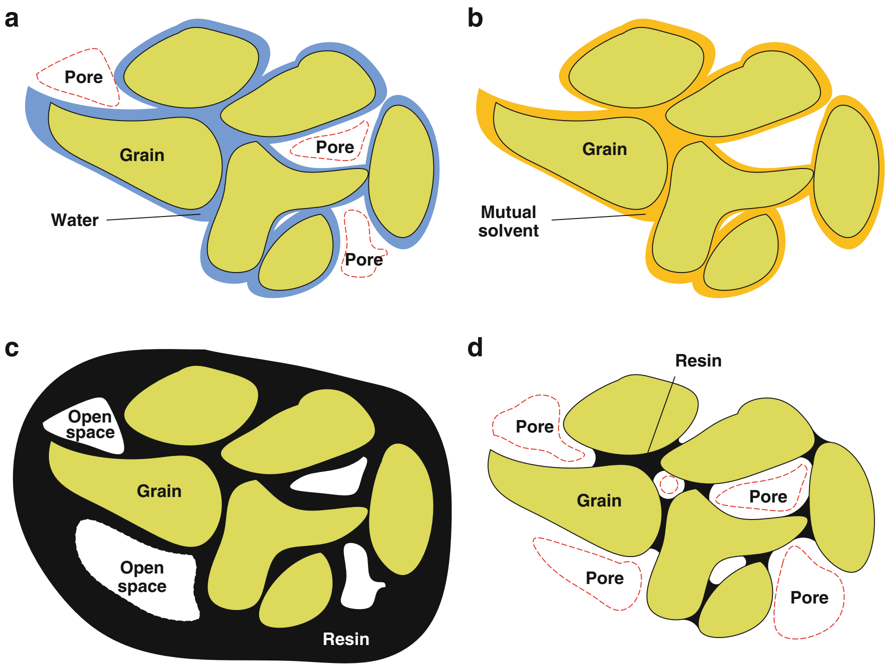


Fig. 4.2 Chemical sand consolidation sequences

(c) *Main treatment fluid is pumped entering the pores by capillary pressure*
(d) *All but residual resin is displaced with overflush connecting the grains at the contact points*

Treatment fluid normally consists of some type of *resin*, *solvent*, *curing agent* (catalyst), *activator* and *accelerator* (optional). Depending on the near wellbore zone cleanliness, pressure, temperature and other properties, diverse resin systems with different additives are used.

When preparing resin treatment fluid, one of the most important factors is formation temperature. It dictates resin hardening time and thus needed concentrations of some additives like accelerators and curing agent. Injection itself must be done below fracture initiation pressure at low rates to provide uniform coverage of formation to be treated (Fig. 4.2c).

In phase separation process polymerizing resin separates from the solvent after some time as a second liquid phase. Capillary forces draw resin into intergranular spaces to the grain-to-grain contact points where it solidifies and interconnects the grains. Permeability is preserved by limiting the volume fraction of the separate resin phase.

Overflush or displacement fluid is used to displace all but residual resin saturation at the grains contact points and to control thickness of the plastic film and compressive strength (Fig. 4.2d). It establishes desired permeability and resin cure time as well.

High yield furan or epoxy solutions are used in these applications commingled with surfactants that help resin adhere to the grains. Overflushes are mostly hydrocarbon based fluids but it is also possible to be water based.

Overflush hardener solution for initiating polymerization containing very reactive acid components and hardeners is also sometimes pumped as a second phase overflush. These systems may contain accelerators and curing agents being quite viscous for sweep efficiency improvement.

Spacers are sometimes pumped to separate different types of fluids pumped in a row (Allen 1982; Schechter 1992).

4.4 Additives

Desired treatment fluids in chemical consolidation are on the rare occasion ready to use without additives since they help them to achieve wanted properties required for proper placement, resin curing and other. Some of these important additives and their main purposes are presented below.

Activators, as very essential additives, are used in treatment fluids to prolong resin placement time and to minimize curing time. It can also be added to second overflush fluid to speed up the curing time. When the activator is already added to the treatment fluid, overflush to retain permeability may be needful, but a plastic set up procurement is not needed, so there is no need for activator addition into the second overflush. Activators require a careful addition to the resin system as the reaction time with resin can lessen considerably.

Accelerators are used to minimize resin curing time (for speeding up the reaction time). In accordance with it, as used in treatment fluids, treatment placement time will be reduced. When pumping and curing time operations are expected to last considerably shorter time then usual, accelerators are introduced to the system.

Surfactants, or surface active agents, are used to lower the surface tension between two liquids or liquid and solid. They can be very effective in removing connate water in preflushing the reservoir. Basically, they are organic compounds acting like dispersants, foaming agents, wetting agents, emulsifiers or detergents.

Isopropyl alcohol (C_3H_8O) is a flammable chemical able to dissolve wide range of compounds. That is the reason why is it used in preflushes for water removal. It evaporates quickly and is not very toxic, unlike other solvents.

EGMBE, or ethylene glycol mono-butyl ether, is a mutual solvent which has solvency for both aqueous and non aqueous liquids. It effectively cleans sand and miscible displaces residual water. The end result of such treatment is better accessibility of resin to intergranular spaces.

4.5 Resin-Coated Proppant Packs

As an alternative to regular chemical consolidation with resins, there is a formation sand exclusion method which incorporates gravel packing and afore-mentioned technique. Principally, it is a gravel packing method with proppant coated with thin layer of resin (Pope et al. 1987; Suman et al. 1983; Dewprashad et al. 1993). Resin layers can be applied to any kind of commercially available proppant. One has to differentiate *pre-coated proppant* in the factory which is then taken to location and *proppant coated on-the-fly* during the treatment. Resin coat is usually curable and after the treatment when the well is shut in, due to high temperature values downhole, resin dissolves and consolidates grains procreating stable packed boundary leaving the formation sand behind it. Stability and permeability of packed zone done with resin-coated proppant depends mainly on resin polymer properties, so the formation temperature awareness and polymer chemical properties are crucial for the job success.

Resins used in these applications are mostly thermosetting epoxy and phenol.

As mentioned earlier, curable proppant can be pre-coated or coated on-the-fly. There is also a *pre-cured* type of proppant that is already heated and cured in the factory where it is mixed with melted resin. The cure is achieved under certain conditions by mixing those two with sufficient mechanical shearing action. Proppant grains end up coated with thermoset resin layer (Coulter and Gurley 1971; Dusterhoft 1994, Rike 1966).

Resin-coated proppant packs are also effectively implemented in frac packing operations where they prevent sand influx at extremely high fracture closing pressures and it's embedding into formation is reduced to minimum. For better understanding, Fig. 4.3 depicts comparison of grains interaction in case of resin-

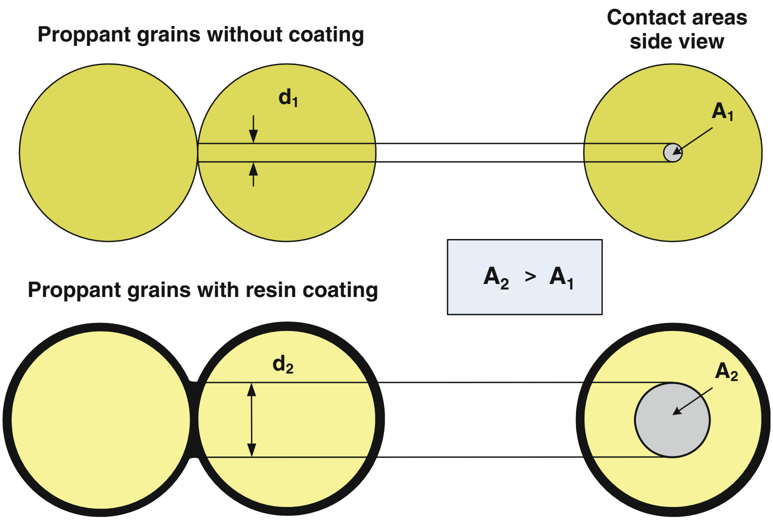


Fig. 4.3 Comparison of proppant grains with and without resin coating

coated proppant and proppant without coatings. On resin-coated proppant stress is allocated over a greater area so a greater breaking resistance of detached grains is achieved.

4.6 Advantages and Disadvantages

Advantages of chemical consolidation with resins over other sand control methods are numerous. Some of them are listed below:

- *Gravel is not required in perforations, so a severe production reduction is not introduced like in case of gravel packing method,*
- *Screens are not used, so mechanical risks caused by installation of such hardware do not exist,*
- *No rig is required, and therefore additional funds for its rent,*
- *Chemical consolidation can be done through existing completion or coiled tubing,*
- *It is quite cheap comparing to gravel packing and frac packing methods,*
- *Convenient and ready for through tubing applications,*
- *Leaves the wellbore fully open without unrestricted ID,*
- *Application possible in abnormal pressure wells,*
- *Good compressive strength in near wellbore zone with 60–90% of original permeability retention. It is possible to retain more then 90% of original productivity.*
- *Can be also used to repair an unsuccessful sand control treatment.*

Basic *disadvantages* of chemical consolidation with resins are:

- *Chemicals handling always poses a threat to safe job performance so they have to be treated with ultimate care,*
- *Formation damage imposed in near wellbore zone by chemical treatment can be substantial. That means a reduced porosity and permeability leading to reduced productivity,*
- *Placement of the whole chemicals volume through all perforations is critical to success.*

4.7 Surface Equipment

Consolidation treatment operation may be sometimes very complex. This is due to the need to prepare the grain surfaces for treatment fluid (preflush), treat the grains with resin system and flush it afterwards with overflush fluid to preserve

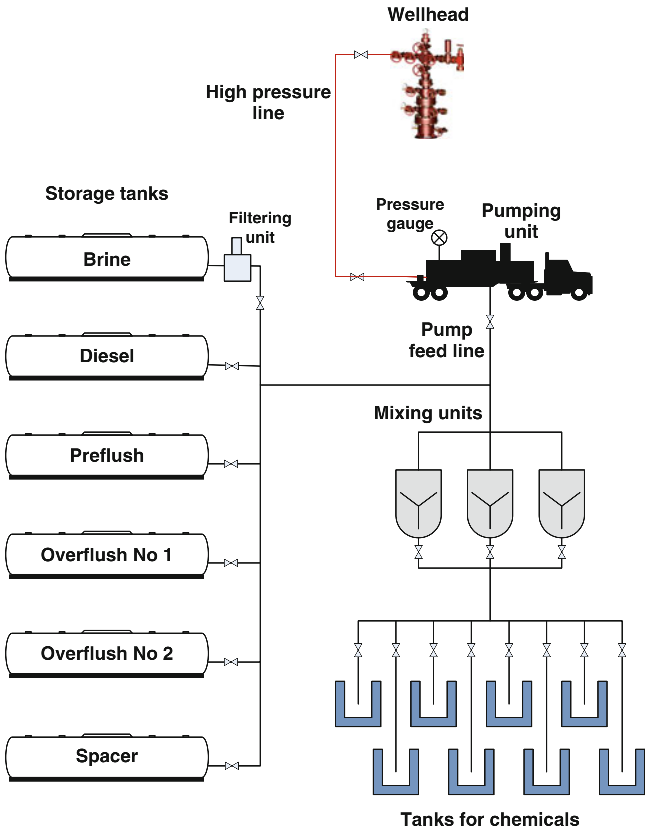


Fig. 4.4 Surface equipment layout for chemical consolidation mixing and pumping process

permeability and flush away undesirable excess chemicals. A series of chemical treatments to be pumped inside the reservoir (preflushes, spacers, resin systems, overflushes) require a huge number of logistical units. Separated storage tanks, manifolds, mixers, high pressure lines, pumps etc. (Fig. 4.4) – they all have to be correctly affixed and connected to be able to perform smooth fluid pumping operations.

References

Allen TO, Roberts AP (1982) Production operations: well completions, workover and stimulation, 622 2nd edn. Oil & Gas Consultants International, Tulsa

Allen TO, Roberts AP (1989) Production operations: well completions, workover and stimulation, 3rd edn. Oil & Gas Consultants International, Tulsa

Bellarby J (2009) Well completion design, vol 56, Developments in petroleum science. Elsevier, Hungary

Brooks FA (1974) Evaluation of preflushes for sand consolidation plastics. In: SPE-AIME symposium on formation damage, paper SPE 4776, New Orleans

Coulter AW, Gurley DG (1971) How to select the correct sand control system for your well. In: Paper SPE 3177, Dallas

Dewprashad B, Abass HH, Meadows DL, Weaver JD, Bennett BJ (1993) A method to select resin-coated proppants. In: 68th annual technical conference, paper SPE 26523, Texas

Dusterhoft RG (1994) FracPac completion services-stimulation and sand-control techniques for high-permeability oil and gas wells. Halliburton Energy Services, Houston

Economides MJ et al (1997) Petroleum well construction. Wiley, Duncan

Kotlar HK, Haavind F, Springer M, Bekkelund SS, Torsaeter O (2005) A new concept of chemical sand consolidation: from idea and laboratory qualification to field application. In: SPE annual technical conference and exhibition, paper SPE 95723, Dallas

Larsen T, Lioliou M, Josang LO, Ostvold T (2006) Quasinatural consolidation of poorly consolidated oilfield reservoirs. In: SPE international oilfield scale symposium, paper SPE 100598, Aberdeen, Scotland

Pope CD, Wiles TJ, Pierce BR (1987) Curable resin-coated sand controls proppant flowback. In: SPE production operations symposium, paper SPE 16209, Oklahoma City

Rike JL (1966) Review of sand consolidation experience in South Louisiana. In: SPE annual fall meeting, paper SPE 1238, Denver

Schechter RS (1992) Oil well stimulation. Prentice-Hall/Simon & Schuster, Englewood Cliffs

Smith TK (1969) Sand consolidation through production tubing. In: SPE annual spring meeting, paper 69-232, New Orleans

Suman GO Jr, Ellis RC, Snyder RE (1983) Sand control handbook, 2nd edn. Gulf Publishing, Houston

Wasnik A, Mete S (2005) Application of resin system for sand consolidation, mud-loss control and channel repairing. In: SPE international thermal operations and heavy oil symposium, paper SPE/PS-CIM/CHOA 97771, Calgary, Canada

Chapter 5
Frac-and-Pack Completion

Contents

D. Matanović et al., *Sand Control in Well Construction and Operation*,
Springer Environmental Science and Engineering,
DOI 10.1007/978-3-642-25614-1_5,

Abstract A relatively short, highly conductive fracture created in a reservoir of moderate to high permeability will breach near-wellbore damage, reduce the drawdown and near-wellbore flow velocity and stresses, and increase effective wellbore radius. Fracturing treatments of this type have two stages: fracture created, terminated by tip-screenout, and fracture inflation and packing. Such a two-stage treatment is the basis of a number of well-completion methods, collectively known as *frac-and-pack*. This technique has been successfully applied, with a range of fracture sizes, to stimulate wells in various reservoirs worldwide.

This chapter discusses the criteria for selecting wells to be frac-and-packed. It is shown how a systematic study of the inflow performance can be used to assess the potential of frac-and-packed wells, to identify the controlling factors, and to optimize design parameters. It is also shown that fracture conductivity is often the key to successful treatment. This conductivity depends largely on proppant size; formation permeability damage around the created fracture has less effect. Appropriate allowance needs to be made for flow restrictions caused by the presence of the perforations, partial penetration, and non-Darcy effects.

The full potential of this completion method can be achieved only if the design is tailored to the individual well. This demands high-quality input data, which can be obtained only from a calibration test.

5.1 Introduction

Frac-and-pack is the generic term for completions that combine the stimulation advantages of hydraulic fracturing with the most effective technique available for sand control in poorly consolidated, high-permeability formations. Frac-and-pack provides a short, wide fracture for bypassing skin damage near the wellbore. Highly conductive proppant is then placed from the leading tip of the fracture all the way to the borehole. This tip-screenout method controls sand production both by maintaining formation stability and by bridging sand directly in the formation rather than allowing it to reach the wellbore.

The practice of applying fracturing and sand control in a single treatment has existed for long time. However, only last two decades have methods, tools and materials been designed to take full advantage of the theory behind tip-screenout (TSO) fracturing as applied to poorly consolidated, high-permeability formations (Roodhart et al. 1994). The impact of hydraulic fracturing on well productivity depends on fracture conductivity (propped width) and length. In medium- to high-permeability reservoirs, fracture length does not affect the outcome as dramatically as in low-permeability reservoirs. Therefore, the key to successful frac-and-pack treatment is to maximize fracture conductivity. This can be achieved with a treatment aggressive enough to induce an early tip-screenout (TSO) (Smith et al. 1987). A TSO occurs when proppant slurry reaches the fracture tip, thereby retarding fracture elongation. Continued injection of the proppant slurry after TSO causes the fracture width to increase as the pressure increases. Therefore, the execution of such fracture treatments consists of two distinct stages: (1) creation of a hydraulic fracture and TSO and (2) fracture inflation and packing.

5.2 Well Selection Criteria

Before frac-and-pack completions are applied to a well, several candidate criteria should be met. Wells with the following characteristics could be the best candidates (Meese et al. 1994):

1. Reservoirs with significant wellbore damage that historically respond poorly to matrix stimulation techniques. An induced hydraulic fracture can bypass damage and connect the wellbore to the reservoir efficiently, thereby reducing skin effects.
2. Poorly consolidated reservoirs that my have fines- and sand-migration problems. An induced hydraulic fracture can alleviate fines movement by providing a large high-permeability flow area, which will reduce near-wellbore velocities. Reduced fines migrations can lead to better cumulative production.
3. Weakly consolidated formations that may fail in shear during the production of the well. A high-conductivity fracture can reduce the stress caused by drawdown while maintaining high productivity.
4. Low-resistivity, laminated sand/shale sequences where the connection of the sand lenses to the wellbore through perforations may be limited. An induced hydraulic fracture can provide an effective vertical connection.
5. Low-permeability reservoirs that require a conductive fracture to improve the overall productivity of the zone. A high-permeability fracture in a low-permeability zone can boost productivity by enhancing the drainage efficiency of the producing zone.

It should be distinguished between treatments for existing wells and those for new wells. Designs for new wells can eliminate mechanical constrains. The mechanical status frequently limits treatments possibilities for existing wells.

The following issues need to be addressed during selection of candidate well for fracturing and packing (Roodhart et al. 1994):

1. The state of reservoir depletion.
2. The nature and extent of near-wellbore permeability damage.
3. A comparison of the well's production with that of equivalent wells completed in the same formation.
4. The reservoir's permeability, the gross and net formation heights and its distribution, and fluid contacts.
5. The formation's mechanical rock properties (e.g. Young's modulus).
6. The formation's tendency to produce sand.
7. The mechanical integrity of the completion with respect to fracturing operations.
8. The operational and economic feasibility of the treatment.

5.3 Inflow Performance

Wells drilled to access petroleum formations cause a pressure gradient between the reservoir pressure and that at the bottom of the well. During production or injection the pressure gradient forces fluids to flow through the porous medium. Central to this flow is the permeability, k, a concept first introduced by Darcy that led to the well known Darcy's law. This law suggests that the flow rate, q, is proportional to the pressure gradient Δp:

$$q \propto k\Delta p \tag{5.1}$$

The fluid viscosity, μ, also enters the relationship, and for radial flow through an area $2\pi rh$, Eq. 5.1 becomes:

$$p - p_{wf} = \frac{q\mu}{2\pi kh} \ln \frac{r}{r_w} \tag{5.2}$$

where p_{wf} and r_w are the bottomhole flowing pressure and wellbore radius, respectively. Equation 5.2 is also well known and forms the basis to quantify the production (or injection) of fluids through vertical wells from porous media. In conjunction with appropriate differential equations and initial and boundary conditions, it is used to construct models describing petroleum production for different radial geometries (van Everdingen and Hurst 1949). These include steady state, where the outer reservoir pressure p_e, is constant at the reservoir radius, r_e; pseudosteady state, where no flow is allowed at the outer boundary ($q = 0$ at r_e); and infinite acting, where no boundary effects are felt. Well-known expressions for these production modes are presented later.

Regardless of the mode of reservoir flow, the near-wellbore zone may be subjected to an additional pressure difference caused by a variety of reasons, which alters the radial (and horizontal) flow converging into the well. The skin effect s, was introduced to account for these phenomena (van Everdingen 1953). Fundamentally a dimensionless number, it describes a zone of infinitesimal extent that causes a steady-state pressure difference, conveniently defined as:

$$\Delta p_s = \frac{q\mu}{2\pi kh} s \tag{5.3}$$

Adding Eqs. 5.2 and 5.3 results in:

$$p - p_{wf} = \frac{q\mu}{2\pi kh} \left(\ln \frac{r}{r_w} + s \right) \tag{5.4}$$

where the p_{wf} in Eq. 5.4 is different from that in Eq. 5.2. A positive skin effect requires a lower p_{wf}, whereas a negative skin effect allows a higher value for a constant rate q. For production or injection, a large positive skin effect is detrimental; a negative skin effect is beneficial.

The well production or injection rate is related to the bottomhole flowing pressure by the inflow performance relationship. Depending on the boundary effects of the well drainage, inflow performance values for steady-state, pseudosteady state and transient (infinite acting) conditions can be developed readily. Equation 5.4 can be converted readily to a steady state expression by simply substituting p with p_e and r with r_e. Thus, with simple rearrangements and after introducing formation volume factor B, the inflow performance relationship for oil well is:

$$q = \frac{2\pi kh\left(p_e - p_{wf}\right)}{B\mu\left(\ln\frac{r_e}{r_w} + s\right)} \tag{5.5}$$

By introducing an average formation volume factor for gas in above equation, an analogous expression for gas well can be obtained. This is provided by the real gas law:

$$pV = nRTZ \tag{5.6}$$

from which an average value of the formation volume factor follows as:

$$\bar{B} = \frac{nRT\bar{Z}/(p_i + p_{wf})/2}{nRT_{sc}/p_{sc}} = \frac{2p_{sc}T\bar{Z}}{T_{sc}(p_i + p_{wf})} \tag{5.7}$$

After introducing this equation into Eq. 5.5 the inflow performance relationship for gas well is approximately:

$$q = \frac{\pi T_{sc}kh\left(p_e^2 - p_{wf}^2\right)}{p_{sc}\bar{\mu}\bar{Z}T\left(\ln\frac{r_e}{r_w} + s\right)} \tag{5.8}$$

where Z is the average real gas deviation factor, T is the absolute temperature, and μ is the average viscosity. T_{sc} and p_{sc} are standard conditions temperature and pressure, respectively. Equation 5.8 has a more appropriate form using real-gas pseudo-pressure function (Al-Hussainy et al. 1966):

$$m(p) = 2\int_{p_{sc}}^{p} \frac{p}{\mu Z}dp \tag{5.9}$$

which eliminates the need to average μ and Z:

$$q = \frac{\pi T_{sc} kh \left[m(p_e) - m(p_{wf}) \right]}{p_{sc} T \left(\ln \frac{r_e}{r_w} + s \right)} \tag{5.10}$$

For two-phase flow, there are several approximations, one of which is the following analytical solution (Raghavan 1976):

$$q_o = \frac{\pi kh (p_e^2 - p_{wf}^2)}{p_e \mu_o B_o \left(\ln \frac{r_e}{r_w} + s \right)} \tag{5.11}$$

The subscript o is added here to emphasize the point that oil properties are used. The subscript is frequently omitted, although it is implied.

At first glance, the expression for pseudosteady-state flow for oil:

$$q = \frac{2\pi kh \left(\bar{p} - p_{wf} \right)}{B\mu \left(\ln \frac{r_e}{r_w} - \frac{3}{4} + s \right)} \tag{5.12}$$

appears to have little difference from the expression for steady state (Eq. 5.5). However, the difference is significant. Equation 5.12 is given in terms of the average reservoir pressure p, which is not constant but, instead, integrally connected with reservoir depletion. Material-balance calculations are required to relate the average reservoir pressure with time and the underground withdrawal of fluids.

The analogous pseudosteady-state expressions for gas and two-phase production are:

$$q = \frac{\pi T_{sc} kh \left[m(\bar{p}) - m(p_{wf}) \right]}{p_{sc} T \left(\ln \frac{r_e}{r_w} - \frac{3}{4} + s \right)} \tag{5.13}$$

$$q_o = \frac{\pi kh (\bar{p}^2 - p_{wf}^2)}{\bar{p} \mu_o B_o \left(\ln \frac{r_e}{r_w} - \frac{3}{4} + s \right)} \tag{5.14}$$

The diffusion partial differential equation, describing radial flow of an incompressible fluid in a porous medium, is (Matthews and Russell 1967):

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} = \frac{\phi \mu c_t}{k} \frac{\partial p}{\partial t} \tag{5.15}$$

Dimensionless expressions for pressure, time and radius are used to generalize Eq. 5.15:

$$p_D = \frac{2\pi kh\Delta p}{qB\mu} \tag{5.16}$$

$$t_D = \frac{kt}{\phi\mu c_t r_w^2} \tag{5.17}$$

$$r_D = \frac{r}{r_w} \tag{5.18}$$

In Eqs. 5.16, 5.17 and 5.18, the subscript D refers to dimensionless quantities. Other variables are p, pressure, t, time, r, distance, ϕ, porosity, μ, viscosity, c_t, total system compressibility, k, permeability, and r_w the well radius. Substituting these equations into Eq. 5.15 produces the dimensionless flow equation:

$$\frac{\partial^2 p_D}{\partial r_D^2} + \frac{1}{r_D}\frac{\partial p_D}{\partial r_D} = \frac{\partial p_D}{\partial t_D} \tag{5.19}$$

This equation provides a well-known solution for an infinite-acting reservoir producing at constant rate at the well (van Everdingen and Hurst 1949):

$$p_D = -\frac{1}{2}Ei\left(-\frac{r_D^2}{4t_D}\right) \tag{5.20}$$

where:

$$-Ei(-x) = \int_x^\infty \frac{e^{-u}}{u}du \tag{5.21}$$

the Ei function or exponential integral. For $x < 0.01$, exponential integral can be approximated by:

$$-Ei(-x) \cong -(\ln x + \gamma) = \ln\left(\frac{1}{x}\right) - \gamma \tag{5.22}$$

where γ is Euler's constant equal 0.577215665.... With this logarithmic approximation, for $r = r_w$ (i.e., at the wellbore), the solution for the dimensionless pressure from Eq. 5.20 becomes simply:

$$p_D = \frac{1}{2}(\ln t_D + 0,80907) \tag{5.23}$$

Equation 5.23 provided the basis of both the forecast of transient well performance and the Horner (1951) analysis, which is one of the mainstays of pressure transient analysis (Earlougher 1977). Although it describes the pressure transients under constant rate, an exact analog for constant pressure exists. In that solution, p_D is replaced simply by the reciprocal of the dimensionless rate $1/q_D$.

The dimensioned and rearranged form of Eq. 5.23, after adding the skin effect, s, given by Eq. 5.3, is:

$$p_i - p_{wf} = \frac{qB\mu}{2\pi kh}\left[\frac{1}{2}\left(\ln\frac{kt}{\phi\mu c_t r_w^2} + 0,80907\right) + s\right] \tag{5.24}$$

where p_i is the initial reservoir pressure. With further rearrangement, the inflow performance relationship for transient flow of oil is:

$$q = \frac{2\pi kh\left(p_i - p_{wf}\right)}{B\mu\left[\frac{1}{2}\left(\ln\frac{kt}{\phi\mu c_t r_w^2} + 0,80907\right) + s\right]} \tag{5.25}$$

As previously done for the pseudosteady-state inflow performance, gas and two-phase analogs can be written:

$$q = \frac{\pi T_{sc}kh\left[m(p_i) - m(p_{wf})\right]}{p_{sc}T\left[\frac{1}{2}\left(\ln\frac{kt}{\phi\mu c_t r_w^2} + 0,80907\right) + s\right]} \tag{5.26}$$

$$q_o = \frac{\pi kh\left(p_i^2 - p_{wf}^2\right)}{p_i\mu_o B_o\left[\frac{1}{2}\left(\ln\frac{kt}{\phi\mu c_t r_w^2} + 0,80907\right) + s\right]} \tag{5.27}$$

The performance of a frac-and-packed well can be expressed in terms of a final completion skin factor, s, which value can be obtained from post-fracture pressure transient analysis, assuming a pseudo-radial flow conditions described by Eq. 5.24. This final skin factor may have contributions from the conductive fracture, s_f, perforation flow, s_{pf}, choked fracture near the wellbore, s_{ck}, fluid leakoff damage to the fracture face, s_{fl}, non-Darcy flow, s_{nD}, partial penetration, s_{pp}, and other possible skins, s_o. That is,

$$s = s_f + s_{pf} + s_{ck} + s_{fl} + s_{nD} + s_{pp} + s_o \tag{5.28}$$

Despite the fact that the frac-and-pack treatment achieved negative values of s_f, s may still be positive as a result of the other terms in Eq. 5.28. The final value of s should be minimized to maximize well productivity.

5.3.1 Fracture Skin Factor

The performance of a fully penetrating, undamaged, finite-conductivity hydraulic fracture, under pseudo-radial flow conditions, may be presented as performance of a completion with an increased effective wellbore radius, r'_w, which is defined as (Prats 1961; Prats et al. 1962):

$$r'_w = r_w e^{-s_f} \tag{5.29}$$

where r_w is the real wellbore radius. The fracture skin factor, s_f, is then defined as:

$$s_f = \ln \frac{r_w}{r'_w} \tag{5.30}$$

Cinco-Ley and Samaniego-V. (1981a) introduced direct correlation of dimensionless effective wellbore radius, r'_{wD}, which is simply:

$$r'_{wD} = \frac{r'_w}{x_f} \tag{5.31}$$

and dimensionless fracture conductivity, C_{fD}, defined as:

$$C_{fD} = \frac{k_f w_f}{k x_f} \tag{5.32}$$

where k_f is the fracture permeability, w_f is the fracture width, k is the reservoir permeability, and x_f is the propped fracture half-length. The correlation is shown in Fig. 5.1. As it can be seen from the figure, when $C_{fD} > 10$, r'_{wD} approaches a constant value equal 0.5, which means that effective wellbore radius is given as:

$$r'_w = 0.5\, x_f \tag{5.33}$$

As C_{fD} compares the relative fluid flow capacity along the fracture with that delivered by the reservoir, in this case the fracture conductivity, $k_f w_f$, is considered to be nearly infinite relative to the fluid deliverability from the reservoir (Cinco-Ley and Samaniego-V. 1981b). In another words, the fracture can produce as much as the reservoir can deliver. This situation is typical for fractures in low-permeability formations.

On the other hand, when $C_{fD} < 1$, r'_{wD} approaches a straight line given as $r'_{wD} = 0.25\, C_{fD}$, which means that effective wellbore radius is equal:

$$r'_w = 0.25\, k_f w_f / k \tag{5.34}$$

In this case, the flow capacity in the fracture limits well productivity, and the reservoir can deliver more flow than the fracture can handle. This situation is typical in higher-permeability formations.

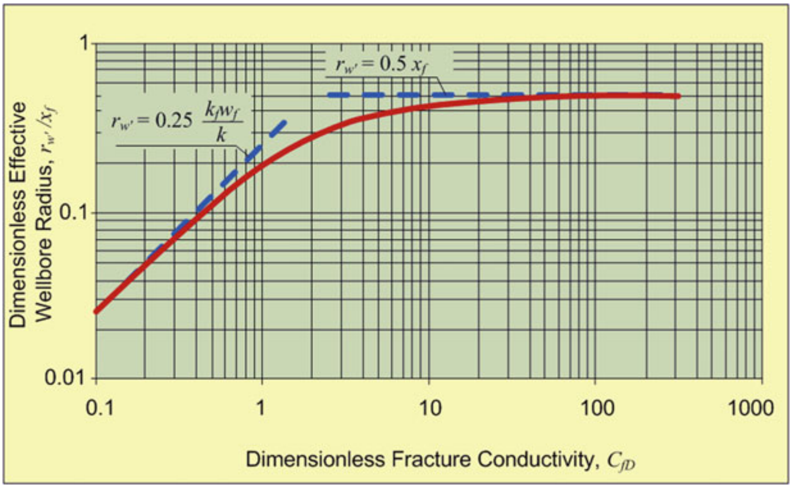


Fig. 5.1 Correlation of dimensionless effective wellbore radius with dimensionless fracture conductivity (Cinco-Ley and Samaniego-V. 1981a)

According to Eq. 5.30, negative value of s_f can be obtained whenever is $r'_w > r_w$. For example, when $C_{fD} > 10$, the values for r'_w for $x_f = 5$ and $x_f = 50$ m are 2.5 and 25 m, respectively. If the real wellbore radius is $r_w = 0.1$ m, the resulting fracture skin factors will be $s_f = -3.22$ and $s_f = -5.52$ respectively. Unfortunately, such high values of C_{fD} are not practical for high-permeability formations. In case of a 500-md formations ($k = 500 \times 10^{-3}$ μm^2), for $w = 20$ mm, $x_f = 20$ m, and $k_f = 100$ μm^2, C_{fD} is only 0.2. According to Eq. 5.34, effective wellbore radius is then $r'_w = 1$ m, which results with fracture skin factor value of only $s_f = -2.3$. Therefore, to minimize s_f, one should maximize the fracture conductivity and length so that C_{fD} is at least >1.

5.3.2 *Perforation Flow Skin Factor*

Reservoir fluid must flow into the fracture and through the perforations, which penetrate the casing and cement sheath, to be produced. Assuming linear Darcy (i.e., laminar) flow in a cylindrical perforation tunnel packed with permeable proppant, the pressure drop, Δp_{pf}, is given as:

$$\Delta p_{pf} = \frac{\mu L_p}{k_p} v = \frac{\mu L_p}{k_p} \frac{4qB}{\pi d_p^2 N} \tag{5.35}$$

where k_p, L_p, and d_p are permeability, length (casing thickness plus cement sheath) and diameter of the perforation tunnel, respectively. N is the number of the perforations that are connected with the fracture. According to the definition of the skin factor (Eq. 5.3), the above equation can be written as:

$$\Delta p_{pf} = \frac{qB\mu}{2\pi kh} s_{pf} \tag{5.36}$$

so that perforation flow skin factor, s_{pf}, can be defined as:

$$s_{pf} = \frac{8L_p}{d_p^2 n_p} \frac{k}{k_p} \tag{5.37}$$

where n_p is the number of the perforations per unit length that are connected with the fracture.

Frac-and-pack treatments are carried out very often from a deviated wellbore. Depending on the orientation of the well to the minimum in-situ stress, a fracture may be started at an angle to the wellbore and the value of n_p may be lower than the actual shooting density. Perforating diameter, d_p, has very big influence on value of s_{pf}. This behavior emphasizes the need for a large perforation diameter and a high shot density.

The impact of frac-and pack design and execution on s_{pf} is described by the ratio of perforation to formation permeability, k_p/k. Typical ratios of k_p/k are from a few tens to a few hundreds. For example, a 40/60 mesh (0.25–0.42 mm) sand with $k_p = 20\ \mu m^2$ in a 500-md formation ($k = 500 \times 10^{-3}\ \mu m^2$) gives $k_p/k = 40$. Using typical completion values of $L_p = 5$ cm, $d_p = 10$ mm, and $n_p = 20$ shots/m, calculated skin factor in this case will be $s_{pf} = +5$, thereby eliminating the benefit of s_f (negative skins) and dominating s. However, s_{pf} can become much larger for lower values of k_p/k, such as those observed when same 40/60 mesh (0.25–0.42 mm) sand is used in the perforations of very permeable formations. Therefore, packing the perforation tunnel with permeable proppant is essential to minimizing s_{pf}. In fact, k_p/k has to exceed 150 for s_{pf} to be less than +1 (for typical completion values).

Larger perforation diameter, high perforation density, and a permeable proppant packing the perforation tunnel are all critical in minimizing s_{pf}. Therefore, the performance of "big hole" charges and gun system should be evaluated in terms of providing sufficient perforation diameter and density. The proppant permeability should be selected to provide a recommended k_p/k value greater than 200. The perforation tunnel may not be packed with proppant if a screenless completion is used, resulting in a large increase in conductivity.

5.3.3 Choked Fracture Skin Factor

The fracture conductivity near the wellbore region can be reduced, or choked, compared with the main part of the fracture because of reduced fracture width (pinched fracture) or reduced proppant permeability. The choked fracture skin is more severe for low-conductivity fractures. This skin factor is given by (Cinco-Ley and Samaniego-V. 1981b):

$$s_{ck} = \frac{\pi x_{ck} k}{w_{ck} k_{ck}} \tag{5.38}$$

where x_{ck}, w_{ck}, and k_{ck} are the choked or damaged fracture half-length, width, and permeability, respectively. Equation 5.38 can be rewritten as:

$$s_{ck} = \frac{\pi}{C_{fD}} A \tag{5.39}$$

where A is defined as:

$$A = \frac{x_{ck}}{x_f} \frac{w_f}{w_{ck}} \frac{k_f}{k_{ck}} \tag{5.40}$$

For some typical ratios of $c_{ck}/x_f = 0.045$, $w_f/w_{ck} = 3$ and $k_f/k_{ck} = 3$ the value of A is about 0.4. Figure 5.2 illustrates the choked fracture mechanism and depicts s_{ck} as a function of C_{fD} for several values of A.

A pinched fracture ($w_f/w_{ck} > 1$) can occur when the fracture is not fully packed before the gravel pack and fracture closure. Under this condition, the near-wellbore proppant may flow toward the fracture tip, settle to the bottom of the fracture, or flow back into the wellbore. Pinched fractures also can occur in deviated wells. For example, the fracture may not have been initiated in a plane perpendicular to the

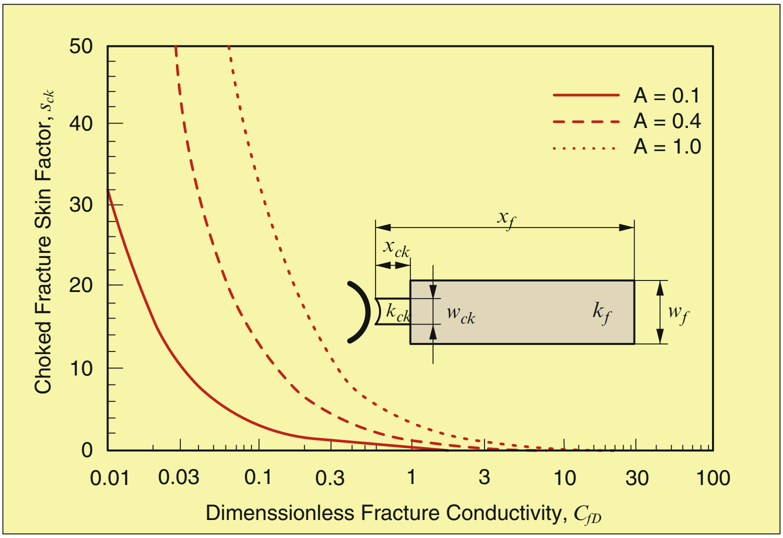


Fig. 5.2 Choked fracture skin factor as a function of C_{fD} (Roodhart et al. 1994)

minimum in-situ stress direction, creating a tortuous path in the wellbore region before connecting with the main fracture. A reduced fracture permeability ($k_f/k_{ck} > 1$) can be caused by unhydrated or partially hydrated gel residues and/or unbroken gels accumulating near the wellbore.

Because s_{ck} is inversely proportional to C_{fD}, it becomes very large for frac-and pack treatments with low C_{fD} values. For example, Fig. 5.2 shows that for $C_{fD} = 0.1$, s_{ck} is either +3.1 or +12.6 for $A = 0.1$ or 0.4, respectively. These high values of choking skin factor can easily eliminate the benefit of the fracture stimulation, s_f. However, the impact of s_{ck} is less severe for frac-and pack treatments with a high fracture conductivity ($C_{fD} > 1$). For example, when $C_{fD} = 1.0$, s_{ck} is either +0.31 or +1.26 for $A = 0.1$ or 0.4, respectively.

Besides design a frac-and-pack with high C_{fD}, one should also take steps during the job to minimize s_{ck}. These steps may include breaking down the fracture with a high pump rate to reduce near-wellbore friction, packing the fracture with high-concentration loading of proppant near the end of the treatment (before gravel packing) to minimize width pinching, or implementing quality control of the fracturing fluid to maximize fracture conductivity.

5.3.4 Fluid Leakoff Damage

The region around the fracture face can be damaged by fluid that has leaked through the face or the filter cake that has formed on it. Assuming linear Darcy (i.e. laminar) flow, this skin factor, s_{fl}, is given as (Cinco-Ley and Samaniego-V. 1981b):

$$s_{fl} = \frac{\pi}{2} \frac{y_{fl}}{x_f} \left(\frac{k}{k_{fl}} - 1 \right) \tag{5.41}$$

where y_{fl} and k_{fl} are the depth and permeability of the damaged region, respectively. Figure 5.3 illustrates this damage mechanism and shows s_{fl} as a function of permeability ratio, k_{fl}/k, for several values of the ratio y_{fl}/x_f.

The magnitude of s_{fl} is generally small as compared to s_{pf} and s_{ck}. For example, s_{fl} is only +0.16 when the damage region has one-half the original reservoir permeability ($k_{fl}/k = 0.5$) and penetrates a distance of one-tenth of x_f ($y_{fl}/x_f = 0.1$). Therefore, the fracture-face damage is generally not as severe as near-wellbore damage.

5.3.5 Partial Penetration and Non-Darcy Skin Factor

Partial penetration of the fracture height causes flow convergence toward the well-bore, which increase non-Darcy (turbulent) flow effect, thus reducing the fracture

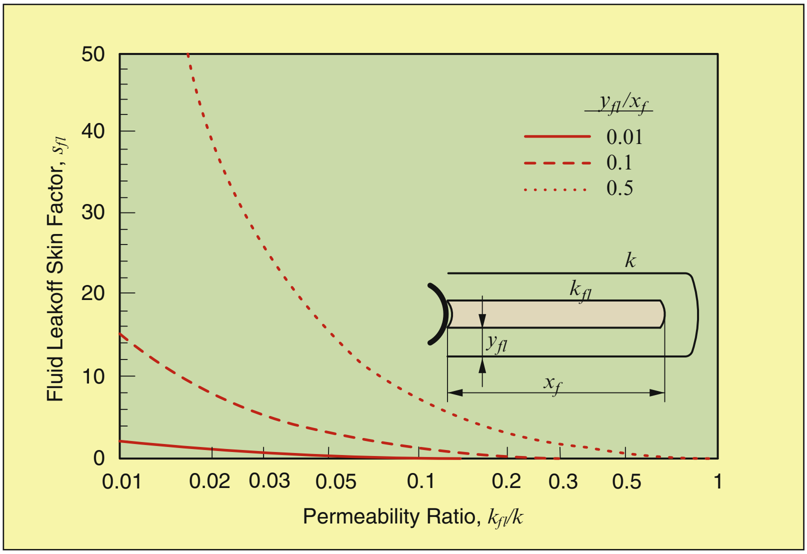


Fig. 5.3 Fracture face skin factor as a function of permeability ratio (Roodhart et al. 1994)

conductivity. Another pressure- and rate-dependent skins that may not be removed with a frac-and-pack treatments can further reduce the fracture conductivity. The influence of these skins on well performance has been studied and results confirm the vital importance oh high fracture conductivity for a successful frac-and pack treatment (Roodhart et al. 1994).

Obviously, each frac-and-pack case is unique and no simple guidelines on optimum fracture geometry can be given. Other factors reducing the conductivity of propped fracture, such as gel residue, invasion of fines, and proppant embedment, will increase the required fracture width even more (Roodhart et al. 1988). Moreover, the fracture conductivity is affected by stress. While in-depth evaluation will not be required for every well in a field with many similar wells, check should nonetheless be made to ensure compliance with the overall stimulation objectives.

5.4 Frac-and-Pack for Sand Control

One very successful application area is the combination of frac-and-pack with gravel packing in reservoirs where sand exclusion is needed but gravel packing alone has been shown to reduce well productivity (Hainey and Troncoso 1992). Frac-and-pack combined with sand-control measures is typically used in relatively permeable unconsolidated or loosely consolidated formations. It is applicable to both initial and remedial sand-control operations, offsetting completion damage while promoting sand control. In fact, frac-and-pack might be able to replace gravel packing for sand control because the reduction of well drawdown resulting from the well's improved inflow performance could reduce sand production.

The need for relatively coarse proppant to obtain good fracture conductivity conflicts with the requirement that proppant size should be kept small, for effective sand control. This latter requirement is often formulated in terms of Saucier's criterion (Saucier 1974) (d_{50} of the proppant should equal five to six times the d_{50} of the formation sand), which was actually established with reference to gravel packs. However, the situation of a frac-and-packed well is different from that of a gravel-packed well. Because flow velocities are order of magnitude lower, frac-and-packed wells can be produced at lower drawdown for the same production rate, and formation stresses are not released after the well goes on production. Long-term sand production may be influenced by tensile failure of near-wellbore formation and internal erosion, both of which are reduced by producing at lower drawdown with lower velocities in a formation under maintained stress. This suggests that it may be possible to relax the sand-exclusion criteria used in frac-and-pack completions.

The present trend in frac-and-pack technology indicates a marked departure from the heritage of gravel-packing, incorporating more and more from hydraulic-fracturing technology. This trend can be seen, for instance, in the fluids and proppants applied. While the original frac-and-pack treatments involved sand sizes and "clean" fluids common in gravel-packing, now the typical proppant size for hydraulic fracturing (20/40-mesh; 0.42–0.84 mm) seems to be dominant. The increasing application of crosslinked fracturing fluids also supported the trend (Economides et al. 1998).

The combination of fracturing and gravel-pack technology normally means relatively small treatments, although the pump rates and pressures are much higher than those for gravel packing alone are. A frac-and-pack in shallow, soft formation (with a low Young's modulus) in principle can be executed with a paddle mixer and a single pump, but it is preferable to use specialized equipment: multiple pumps with sufficient hydraulic horsepower; computerized low-volume blender; and appropriate sand storage and transport equipment. The specialized equipment is essential when deeper or harder formations have to be treated.

5.5 Key Issues in Frac-and-Pack Completion

5.5.1 Tip-Screenout

The critical elements of frac-and-pack treatment design, execution, and interpretation are substantially different than for conventional fracturing treatments. In particular, frac-and-pack relies on a carefully timed tip-screenout (TSO) to limit fracture growth and allow for fracture inflation and packing. The TSO occurs when sufficient proppant has concentrated at the leading edge of the fracture to prevent further fracture extension. Once fracture growth has been arrested (and assuming the pump rate is larger than the rate of leakoff to the formation), continued pumping will inflate the fracture (increase fracture width). This TSO and fracture inflation should be accompanied by an increase in net fracture pressure. Thus, the treatment can be conceptualized in two distinct stages: fracture creation (equivalent to conventional designs) and fracture inflation/packing (after tip-screenout).

Figure 5.4 compares the two-stage frac-and-pack process with the conventional single-stage fracturing process. Shaded area indicates the part of the fracture filled with proppant. The darkness of the shading indicates the proppant concentrations. Creation of the fracture and the arrest of its growth (tip-screenout) are accomplished by injecting a relatively small pad and a 200–500 kg/m^3 sand slurry. Once fracture growth has been arrested, further injection builds fracture width and allows injection of high-concentration (1,200–2,000 kg/m^3) slurry. Final areal proppant concentrations of 100 kg/m^2 are not uncommon. The figure also illustrates the common practice of retarding injection rate near the end of the treatment (coincidental with opening the annulus to flow) to dehydrate/pack the near wellbore and screen. Rate reductions may also be used to force tip-screenout in cases where no TSO event is observed on the downhole pressure record.

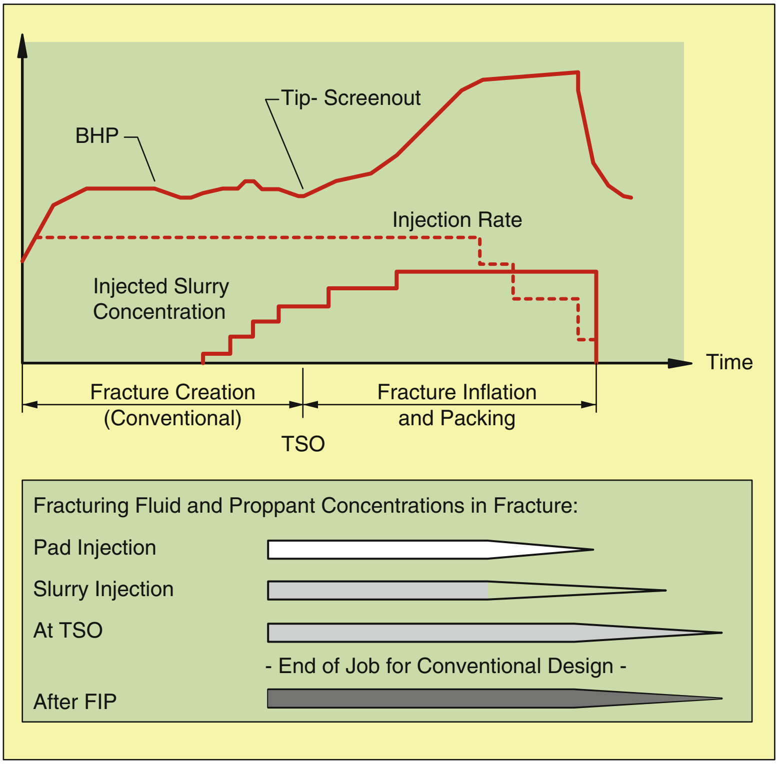


Fig. 5.4 Comparison of conventional and frac-and-pack design concepts (Roodhart et al. 1994)

Industry experience suggests that the tip-screenout can be difficult to model, affect, or even detect. The many reasons for this difficulty include a tendency toward overly conservative design models (resulting in no TSO), partial or multiple tip-screenout events, and inadequate pressure monitoring practices.

It is now well accepted that accurate bottomhole measurements are imperative for meaningful treatment evaluation. Calculated bottomhole pressures are unreliable because of the dramatic friction pressure effects associated with pumping high sand concentrations through reduced-ID tubulars and service-tool crossovers. Surface data may indicate that a TSO event has occurred when the bottomhole data shows no evidence, or the opposite may be true.

5.5.2 Net Pressure and Fluid Leakoff Considerations

The entire frac-and-pack process is dominated by net pressure and fluid leakoff considerations, first because high-permeability formations are typically soft and exhibit low elastic modulus values, and second, because the fluid volumes are relatively small and leakoff rates are high (high permeability, compressible reservoir fluids, and non-wall-building fracturing fluids).The tip-screenout design itself also affects net pressure. While traditional practices applicable to design, execution, and evaluation in conventional fracturing continue to be used in frac-and-pack treatments, these are frequently not sufficient.

5.5.2.1 Net Pressure, Closure Pressure, and Width in Soft Formations

Net pressure is defined as the difference between the pressure at any point in the fracture and the fracture closure pressure. This definition involves the existence of a unique closure pressure. Whether the closure pressure is a constant property of the formation, or it depends heavily on the pore pressure (or rather on the disturbance of the pore pressure relative to the long-term steady value) is an open question.

In high-permeability, soft formations, it is difficult (if not impossible) to suggest a simple recipe to determine the closure pressure as classically derived from shut-in pressure decline curves. Furthermore, because of the low elastic modulus values, even small, induced uncertainties in the net pressure are amplified into large uncertainties in the calculated fracture width.

5.5.2.2 Fracture Propagation

Fracture propagation is not yet a well-described phenomenon. Recent studies (Chudnovsky et al. 1996) emphasize the stochastic character of this propagation in competent hard-rock formations. No serious attempt has been made to describe the physics of fracture propagation in soft rock, but it is reasonably expected to involve incremental energy dissipation and more severe tip effects (with the effect of increasing net pressures). Again, because of the low modulus values, an inability to predict net-pressure behavior may lead to significant differences between predicted and actual treatment performance. Ultimately, the classic models may not reflect even the main features of the propagation process.

Currently, fracture propagation and net-pressure features are predicted through the use of a computer fracture-simulator, adjusted for the use in a frac-and-pack process.

5.5.2.3 Leakoff in the High-Permeability Environment

Considerable effort has been expended on laboratory investigation of the fluid leakoff process for high-permeability cores. A comprehensive report can be found in both Vitthal and McGowen (1996) and McGowen and Vitthal (1996). The results rise some questions about how effectively fluid leakoff can be limited by filter-cake formation.

In all cases, but especially in high-permeability formations, the quality of the fracturing fluid is only one of the factors that influence leakoff, and it is often not the determining one. Transient fluid flow in the formation might have an equal or even larger impact. Transient flow cannot be understood by simply fitting an empirical equation to laboratory data: the use of models based on solutions to the fluid flow in porous media is an unavoidable step.

Three models that describe leakoff in the high-permeability environment should be considered. The traditional Carter leakoff model (Howard and Fast 1970) requires some modification for use in frac-and-pack. While this model continues to be used almost exclusively across the industry, it is not entirely sufficient for the frac-and-pack application. An alternate, filter cake-based leakoff model has been developed based on the work by Mayerhofer et al. (1995). The most appropriate but not yet widespread leakoff model for high-permeability formations may be that of Fan and Economides (1995b), which considers the series resistance caused by (1) the filter cake, (2) the polymer-invaded zone, and (3) the reservoir. While the Carter model is the most common in current use, the models of Mayerhofer et al. and Fan and Economides represent important building blocks and provide a conceptual framework for understanding the critical issue of leakoff in frac-and-pack.

To make use of material balance, the term V_L, the lost volume, must be described. For rigorous theoretical development, V_L is the volume of liquid entering the formation through the two created fracture surfaces of one wing. There are two main philosophies concerning leakoff. The first considers the phenomenon as a material property of the fluid rock system. The basic relation (called the integrated Carter equation) is given as:

$$\frac{V_L}{A_L} = 2C_L\sqrt{t} + S_p \tag{5.42}$$

where A_L is the area and V_L is the total volume lost during the period from time zero to time t. The integration constant, S_p, is called the spurt-loss coefficient. It can be considered as the width of the fluid body passing through the surface instantaneously at the very beginning of the leakoff process, while $2C_L\sqrt{t}$ is the width of the fluid body following the first slug. The two coefficients, C_L, and S_p, can be determined from laboratory tests. Equation 5.42 can be visualized assuming that the given surface element "remembers" when it has been opened to fluid loss and has its own "zero" time, which might be different from location to location on a fracture surface. Points of the fracture face near to the well are opened at the beginning of pumping while the points at the fracture tip are "younger." Application of Eq. 5.42 or of its differential form necessitates the tracking of the opening time of the different fracture-face elements.

The second philosophy considers leakoff as a consequence of flow mechanisms into the porous medium and uses a corresponding mathematical description (Mayerhofer et al. 1995; Fan and Economides 1995b).

5.6 Treatment Design and Execution

Most frac-and-pack treatments are done with mechanical sand control equipment in place. While this is not always the case, and while there are many potential variations, a generalized job sequences follow:

1. Perforate the formation.
2. Run the gravel-pack screen assembly.
3. Spot/soak acid to clean up perforations.
4. Perform and interpret pretreatment diagnostic tests.
5. Design the TSO pumping schedule based on design variables from diagnostic tests.
6. Pump the TSO treatment until screenout or until the volume needed to form an annulus pack remains in workstring.
7. Slow the pump rate to 0.15–0.3 m^3/min and open the annulus valve to circulate in and dehydrate an annular pack.
8. Shut down the pumps when tubing pressure reaches its safe upper limit.
9. Prepare the well for production.

5.6.1 Perforations

It is widely agreed that establishing a conductive connection between the fracture and wellbore is critical to the success of frac-and-pack, but no consensus or study has emerged that gives definitive direction. In the context of high permeability and maximizing conductivity and fluid flow rate, a common response is to shoot the entire target interval with high shot-density and large holes (40 shots/m with "big hole" charges). Concerns with clean formation breakdown (single-fracture initiation), near-well tortuosity, and perforations that are not packed with sand (especially in screenless frac-and-packs) cause some operators to use just the opposite treatment: perforating the middle of the target zone only (possibly modifying the treatment up or down based on stress contrast) with a limited number of 0 or 180 phased perforations.

Arguments are made for and against underbalanced vs. overbalanced perforating: underbalanced perforating may cause formation failure and cause the guns to "stick," while overbalanced perforating eliminates a cleanup trip but may negatively impact the completion efficiency.

Solvent or other scouring pills are commonly circulated to the bottom of the workstring and then reversed out to remove scale, pipe dope, or other contaminants before they are pumped into the formation. Few cubic meters (0.15–0.3 m^3/m) of 10–15% HCl acid will then typically be circulated or bullheaded down to the perforations and be allowed to soak, (to improve communication with the reservoir by cleaning up the perforations and dissolving debris in the perforation tunnel). Some operators are beginning to forego the solvent and acid cleanup (obviously to reduce rig time and associated costs) from the perspective that, in frac-and-pack, the damaging material is pumped deep into the formation and will not seriously impact well performance.

5.6.2 Mechanical Considerations

The vast majority of frac-and-pack treatments have been performed with the mechanical sand-control equipment in place. However, in some early jobs, the tip-screenout and gravel pack were done in two steps separated by a cleanout trip. Concerns with fluid loss damage to the fracture and a desire to eliminate all unnecessary expense eventually discouraged this two-step approach. More recently, there is a trend toward screenless frac-and-packs.

Early treatments were overwhelmed by rate and erosion-resistance limitations of the gravel-pack tools. Enlarged crossover ports have now been incorporated in the gravel-pack tools of all the major service companies, which minimize friction and erosion problems and allow for very aggressive treatment designs. The aggressive pumping schedules, in turn, have given rise to another problem: Tiner et al. (1996) report several instances where the blank liner above the screen has been collapsed at screenout. They suggest that the pressure outside the blank rises quicker than the internal pressure, resulting in a collapse of this "weak link." The suggested remedy is the use of P-110 grade pipe for the blank.

Limitations were also evident in the surface equipment used on early treatments. The tendency was to approach these treatments (especially offshore) as an oversized gravel-pack operation. While frac-and-pack volumes are relatively small for a fracture treatment, the high rates (3 m^3/min is common) and high proppant concentrations (up to 2,000 kg/m^3) require high horsepower. Undersized gravel-pack units were often used in early jobs; otherwise, miscellaneous onshore fracturing units were hobbled together and placed on barges. This practice resulted in many failed treatments. Today, dedicated skid-mount units with fixed manifolds are widely available and provide adequate horsepower (including standby) within stringent space and weight limitations. Reliable mixing and blending equipment is now available to achieve the various fluid and additive specifications of frac-and-pack, including very-low to very-high proppant concentrations and slurry rates. Other than these considerations, the surface equipment is common to that used in conventional fracturing operations.

5.6.3 Pretreatment Diagnostic Tests

The objective of pretreatment diagnostic tests (referred to as fracture calibration tests, minifracs, datafracs, etc.) is to determine within engineering bounds, the value of various parameters that govern the fracturing process. Fracture closure pressure (considered in most cases as equivalent to the minimum horizontal in-situ stress) and the fluid leakoff coefficient (used to describe bulk leakoff behavior) are the most common targets and are especially important in frac-and-pack as discussed previously. However, other information may also be sought or inferred, such as: (1) fracture extension or propagation pressure (often referred to as formation parting pressure), (2) potential perforation or near-wellbore friction, (3) evidence of fracture-height containment, and (4) reservoir permeability.

Several features unique to high-permeability fracturing make well-specific design strategies highly desirable if not essential: (1) fracture design in soft formations is very sensitive to leakoff and net pressure, (2) the controlled nature of the sequential tip-screenout/fracture inflation and packing/gravel-packing process demands relatively precise execution strategies, and (3) the treatments are very small and typically "one-shot" opportunities. Furthermore, methods used in hard-rock fracturing for determining critical fracture parameters a priori (geologic models, log and core data or Poisson's ratio computational models based on poroelasticity) are of limited value or not yet adapted to the unconsolidated, soft, high-permeability formations.

The preceding discussion of advanced leakoff models and their applicability to pressure falloff analysis notwithstanding, three tests (with variations) form the current basis of pretreatment testing in high-permeability formations: step-rate tests, minifrac tests, and pressure falloff tests.

5.6.3.1 Step-Rate Tests

The step-rate test (SRT), as implied by its name, involves injecting clean gel at several stabilized rates, beginning at matrix rates and progressing to rates above fracture extension pressure. In a high-permeability environment, a test may be conducted at rate steps of 0.1, 0.2, 0.3, 0.6, 1, 1.5 and 2 m^3/min, and then at the maximum attainable rate. The injection is held steady at each rate step for a uniform time interval, typically 2 or 3 min at each step.

In principle, SRTs are intended to identify the fracture extension pressure and rate. The stabilized pressure (ideally bottomhole pressure) at each step is classically plotted on a Cartesian graph vs. injection rate. The point at which a straight line drawn through those points that are obviously below the fracture extension pressure (dramatic increase in bottomhole pressure with increasing rate) intersects with the straight line drawn through those points above the fracture extension pressure (minimal increase in pressure with increasing rate) is interpreted as the fracture extension pressure. The dashed lines in Fig. 5.5 illustrate this classic approach.

While the conventional SRT is operationally simple and inexpensive, it is not necessarily accurate. A Cartesian plot of bottomhole pressure versus injection rate, in fact, does not generally form a straight line for radial flow in an unfractured well. Simple pressure transient analysis of SRT data through the use of de-superposition techniques shows that with no fracturing, the pressure vs. rate curve should exhibit upward concavity. Thus, the departure of the real data from ideal behavior may occur at a pressure and rate well below that indicated by the classic intersection of the straight lines (Fig. 5.5).

The two-SRT procedure of Singh and Agarwal (1990) is more fundamentally sound. However, given the relatively crude objectives of the SRT in high-permeability fracturing, the conventional test procedure and analysis may be sufficient.

The classic test does indicate several things:

- Upper limit for fracture-closure pressure (useful in analysis of minifrac pressure falloff data)
- Surface treating pressure that must be sustained during fracturing (or whether sustained fracturing is even possible with a given fluid)

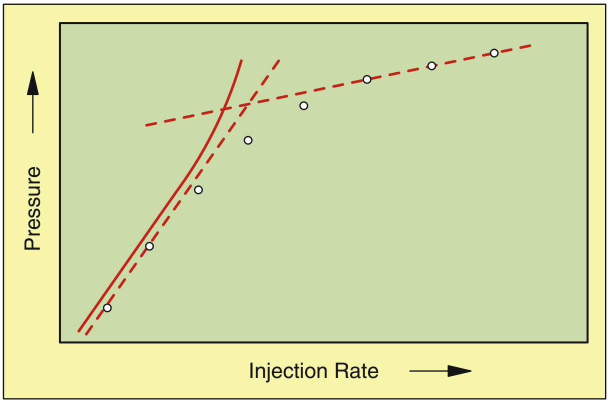


Fig. 5.5 Ideal SRT and radial flow with no fracturing (Economides et al. 1998)

- Reduced rates that will ensure no additional fracture extension and (aided by fluid leakoff) packing of the fracture and near-wellbore with proppant
- Perforation and/or near-wellbore friction (indicated by bottomhole pressures that continuously increase with increasing rate, seldom a problem in soft formations with large perforations and high shot-densities)
- Expected casing pressure if the treatment is pumped with the service tool in the circulating position

A step-down option to the normal SRT is sometimes used specifically to identify near-wellbore restrictions (tortuosity or perforation friction). This test is usually done immediately following a minifrac pump-in stage. By observing how bottomhole pressure varies with decreasing rate, near-wellbore restrictions can be immediately detected; for example, bottomhole pressures that change only gradually during steps down in injection rate would indicate no restriction.

5.6.3.2 Minifrac Tests

Following the SRT, which establishes the fracture extension pressure and places an upper bound on fracture closure pressure, a minifrac is typically performed to tailor or redesign the frac-and-pack treatment with well-specific information. This test is the critical pretreatment diagnostic test. The minifrac analysis and treatment redesign is now commonly done on site in less than an hour, or 2–3 h at the most.

Concurrent with the rise of frac-and-pack, minifrac tests and especially the use of bottomhole pressure information have become much more common. Otherwise, the classic minifrac procedure and primary outputs (fracture closure pressure and a single leakoff coefficient) are widely applied to frac-and-pack - this in spite of some rather obvious shortcomings.

The first step in analyzing a minifrac is determining fracture closure pressure, which is typically done by plotting the pressure decline after shut-in vs. some function of time. The main plots used to identify fracture closure are:

- $p_{shut-in}$ vs. t
- $p_{shut-in}$ vs. $\sqrt{t}$
- $p_{shut-in}$ vs. G-function

The selection of closure pressure using these plots, a difficult enough task in hard-rock fracturing, has proved to be arbitrary or nearly impossible in high-permeability, high fluid-loss formations. In some cases, the duration of the closure period is so limited (1 min or less) that the pressure signals is masked by transient phenomena. Deviated wellbores and laminated formations, multiple fracture closures, and other complex features are often evident during the pressure falloff. The softness (low elastic modulus) of these formations results in very subtle fracture closure signatures on the pressure decline curve. Flowbacks are not used to accent closure features because of the high leakoff and concerns with production of unconsolidated formation sand.

Various practitioners are pursuing new guidelines and diagnostic plots for determining closure pressure in high-permeability formations, and this information will eventually emerge to complement or replace the standard analysis and plots.

The shortcomings of classic minifrac analysis are further exposed when they are used (commonly) to select a single effective fluid-loss coefficient for the treatment. In low-permeability formations, this approach results in a slight overestimation of fluid loss and actually provides a factor of safety to prevent screenout. In high-permeability formations, the classic approach can dramatically underestimate spurt loss (zero spurt-loss assumption) and overestimate total fluid loss (Dusterhoft et al. 1995). This uncertainty in leakoff behavior makes the controlled timing of a tip-screenout very difficult. Dusterhoft et al. outlined various procedures to correct for spurt loss and leakoff behavior that is not proportional to the square root of time; however, entirely new procedures based on sound fundamentals of leakoff in frac-and-pack are ultimately needed. The traditional practice of accounting for leakoff with a bulk leakoff coefficient is simply not sufficient for this application.

5.6.3.3 Pressure Falloff Tests

A third class of pretreatment diagnostics for frac-and-pack has emerged that is not common to conventional fracturing: pressure falloff tests. Because of the high formation permeability, common availability of high-quality bottomhole pressure data and multiple pumping and shut-in cycles, matrix formation properties including *kh* and skin can be determined from short-duration pressure falloff tests with the appropriate transient flow equation. Chapman et al. (1996) and Barree et al. (1996) propose prefrac or matrix injection falloff tests that involve injecting completion fluid below fracturing rates for a given period, and then analyzing the pressure decline with a Horner (1951) plot. The test is performed with standard pumping equipment, and it poses little interruption to normal operations. A test can normally be completed within 1 h or may even make use of data from unplanned injection/shut-in cycles. The resulting permeability certainly relates to fluid leakoff and it allows the engineer to better anticipate fluid requirements. An initial skin value is useful in “benchmarking” the frac-and-pack treatment and for comparison with post-treatment pressure transient analysis.

5.6.3.4 Bottomhole Pressure Measurements

A discussion of pretreatment diagnostic tests requires a discussion of the source of pressures used in the analysis. Implicit to the discussion is that the only meaningful pressures are those adjacent to the fracture face, whether measured directly or translated to that point. At least four different types of bottomhole pressure data are available, depending on the location at which the real data were taken:

- Calculated bottomhole pressure (bottomhole pressure calculated from surface pumping pressure)
- Deadstring pressure (open annulus and bottomhole pressure determined based on the density of fluid in annulus; tubing may also be used as a deadstring when the treatment is pumped down the casing)
- Bundle carriers in the workstring (measured down-hole, but above the service tool crossover)
- Washpipe data (from sensors attached to washpipe below the service-tool crossover)

Washpipe pressure data is the most desirable for frac-and-pack design and analysis because of its location adjacent to the fracture and downstream of all significant flowing pressure drops. Workstring bundle carrier data can introduce serious error in many cases because of fluid friction generated both through the crossover tool and in the casing/screen annulus. Without detailed friction-pressure corrections that account for specific tool dimensions and annular clearance, significant differences may exist between washpipe and workstring bundle carrier pressures (Mullen et al. 1994). Deadstring pressures are widely used and considered acceptable by most practitioners; others suggest that redundant washpipe pressure data has shown that the deadstring can miss subtle features of the treatment. The use of bottomhole transducers with real-time surface readouts is suggested in cases where a deadstring is not feasible or when such well conditions as transients may obscure important information. The calculation of bottomhole pressures from surface pumping pressure is not recommended in frac-and-pack treatments. The combination of heavy sand-laden fluids, constantly changing proppant concentrations, very high pump rates, and short pump times makes the estimation of friction pressures nearly impossible.

5.6.4 Tip-Screenout Design

The tip-screenout or TSO design clearly differentiates high-permeability fracturing (frac-and-pack) from conventional massive hydraulic fracturing (MHF). While frac-and-pack introduces other identifiable differences, such as higher permeability, softer rock, smaller proppant volumes, etc., it is the tip-screenout which makes these fracturing treatments unique. Conventional treatments are designed to achieve TSO at the end of pumping. In high-permeability fracturing, the *fracture creation* stage that precedes TSO is followed by *fracture inflation and packing* stage; this two-stage treatment gives rise to the vernacular *frac-and-pack*. These conventional and frac-and-pack design concepts are illustrated and compared in Fig. 5.4.

Because of the rapid ascent of high-permeability fracturing, many engineers did not have (and still do not have) computer models that accommodate the TSO design. By definition (Nolte 1979, 1986), conventional fracture design systems were formulated with TSO as the endpoint. A no-growth fracture inflation and packing stage had not been envisioned, never mind entering the necessary design algorithms into a computer model. Recently, however, several of the commercially available simulators have been modified to accept the TSO designs. The in-house simulators of many producing companies and oilfield service companies have also been modified.

Given the near-crippling dependence of the modern petroleum engineer on "black-box" solutions, one is compelled to ask how engineers effected a TSO design before the modified computer programs were available. What is the key? An experienced engineer would recognize that after TSO (assuming complete arrest of fracture growth), the problem is reduced to a simple one of material balance.

Wong et al. (1993) offer the following algorithm that can be used with any conventional 2D simulator to develop a fundamentally sound tip-screenout design:

1. It is assumed that the following fracture parameters are known at the end of the TSO stage (from the simulator):

   A_o= fracture area at TSO
   t_o= total time to TSO
   M_{tso}= total proppant mass
   $\Delta p(t_o)$= net pressure at TSO
   $V_F(t_o)$= fracture volume at TSO

2. For every ith stage of the fracture inflation and packing (FIP) pumping schedule, the clean fluid volume (V_{ci}) and the pumping time for the ith stage (t_i) are given in terms of known slurry volume (V_i), proppant concentration (c_i), pump rate (q_i), and proppant density (ρ_p):

$$V_{ci} = V_i \rho_p / (\rho_p + c_i) \tag{5.43}$$

and

$$t_i = V_i / q_i \tag{5.44}$$

3. Cumulative time from TSO to the ith stage is simply:

$$T_i = \sum t_i \tag{5.45}$$

4. Assuming that the fracture area ceases to propagate after TSO, the fluid leakoff rate (q_l) and leakoff volume (V_l) at any time T_i are given (for low-efficiency conditions) as:

$$q_l(T_i) = 2C_L A_o \left(1/\sqrt{t_o}\right) \arcsin\left(1/\sqrt{\tau_i}\right) \tag{5.46}$$

and

$$V_l(T_i) = 2C_L A_o \sqrt{t_o}\left[\tau_i \arcsin(1/\tau_i) + \sqrt{\tau_i - 1}\right] \tag{5.47}$$

where

$$\tau_i = (t_o + T_i)/t_o \tag{5.48}$$

and C_L is the fluid leakoff coefficient.

5. The following material balance relations can be easily implemented in a spreadsheet program and used to calculate fracture parameters at any time T_i:

$$V_f(T_i) = \sum V_{ci} - V_l(T_i) \tag{5.49}$$

$$V_f(T_i) = V_F(t_o) + \sum V_i - V_l(T_i) \tag{5.50}$$

$$M_{fip}(T_i) = M_{tso} + \sum (c_i V_{ci}) \tag{5.51}$$

$$c_m(T_i) = M_{fip}(T_i)\big/V_f(T_i) \tag{5.52}$$

$$APC(T_i) = M_{fip}(T_i)/A_o \tag{5.53}$$

and

$$\Delta p(T_i) = \Delta p(t_o)\frac{V_F(T_i)}{V_F(T_o)} \tag{5.54}$$

where V_f is the total (two-wing) fluid volume, V_F is the total fracture volume, M_{fip} is the total amount of proppant, c_m is the average proppant concentration loading, APC is the average areal proppant concentration, and Δp is the net pressure.

Using the relations above, a TSO design is developed that specifies pump rate, slurry volume, and proppant loading during fracture inflation and packing in as many stages as deemed appropriate. Design objectives include (1) achieving a desired fracture width (from areal proppant concentration) and (2) ensuring that the proppant does not dehydrate prematurely ($c_{\mathrm{m}} \le \rho_p\big/\left(\rho_p/\rho'_p - 1\right)$ where is ρ_p proppant particle density and $\rho_p{}'$ proppant bulk density).

Early TSO treatment designs commonly called for 50% pad (similar to conventional fracturing) and a fairly aggressive proppant ramping schedule; however, it is now increasingly common to reduce the pad to 10–15% of the treatment and extend the 60–240 kg/m^3 stages (which combined, may comprise 50% of total slurry volume, for example). This practice is intended to "create width" for the higher concentration proppant addition (1,400–1,700 kg/m^3).

5.6.5 Pumping a TSO Treatment

Observations related to real-time frac-and-pack experiences are abundant in the literature and most of them are not the focus of this text. However, some observations related to treatment execution are necessary:

- Most treatments are pumped with a gravel-pack service tool in the "circulate" position with the annulus valve closed at the surface. This practice allows for live annulus monitoring of bottomhole pressure (annulus pressure + annulus hydrostatic head) and real-time monitoring of the progress of the treatment.
- When no evidence exists of the planned TSO on the real-time pressure record, the late treatment stages can be pumped at a reduced rate to effect a tip-screenout. Obviously, this practice requires reliable bottomhole pressure data and direct communication with the frac unit operator.
- Near the end of the treatment, the pump rate can be slowed to gravel-packing rates, and the annulus valve can be opened to begin circulating a gravel pack. The reduced pump rate is maintained until tubing pressure reaches a safe upper limit, signaling that the screen casing annulus is packed.
- Because very high proppant concentrations are used, the sand-laden slurry used to pack the screen/casing annulus must be displaced from the surface with clean gel well before the end of pumping. Thus, proppant addition and slurry volumes must be metered carefully to ensure that there is sufficient proppant left in the tubing to place the gravel pack (to avoid "overdisplacing" proppant into the fracture).
- Conversely, if a frac-and-pack treatment sands out prematurely (with proppant in the tubing), the service tool can be moved into the "reverse" position and the excess proppant can be circulated out.
- Movement of the service tool from the squeeze circulating position to the reverse position can create a sharp instantaneous drawdown effect, and it should be done carefully to avoid swabbing unstabilized formation material into the perforation tunnels and annulus.

5.7 Fracture Conductivity and Materials Selection

5.7.1 Optimum Fracture Dimensions

Much has been published recently concerning optimum fracture dimensions in frac-and-pack. While there are debates regarding the optimum dimensions, fracture conductivity is largely regarded as more important than fracture length. Of course, this intuitive statement only recognizes the first principle of fracture optimization: Higher permeability formations require higher fracture conductivity to maintain an acceptable value of the dimensionless fracture conductivity, C_{fD}.

So how long should the fracture be? A "rule of thumb" is that fracture length should be equal to half the perforation height (thickness of producing interval). Alternatively, Hunt et al. (1994) showed that cumulative recovery from a well in a 100-md reservoir ($k = 100 \times 10^{-3}$ μm^2) with a 10-ft damage radius ($r_s = 0.3$ m) is optimized by extending a fixed 8,000-md-ft conductivity fracture ($k_f w_f = 0.244$ μm^2 × m) to any appreciable distance beyond the damaged zone. This result implies that there is little benefit to a 50-ft fracture length ($x_f = 15$ m) compared to a 10-ft fracture length ($x_f =$ 3 m). Two observations are in order: first, the Hunt et al. evaluation is based on cumulative recovery; second, their assumption of fixed fracture conductivity implies decreasing dimensionless fracture conductivity with increasing fracture length (less than optimal placement of the proppant).

It is generally true that if an acceptable C_{fD} is maintained, additional length will provide additional production. (An acceptable C_{fD} may require an increase in areal proppant concentration from 5 kg/m^2, which is common in hard-rock fracturing, to 100 kg/m^2 or more.) Ultimately, the decision becomes one of economics and/or optimal placement of a finite proppant volume (as in offshore environments where total fluid and proppant volumes may be physically limited).

These issues are discussed in the following sections.

5.7.1.1 Fracture Width as a Design Variable

In practice, fracture extent and width have been difficult to influence separately. Once a fracturing fluid and injection rate are selected, the fracture width evolves with increasing length according to strict relations (at least in the well-known PKN and KGD design models). Therefore, the key decision variable has been the fracture extent. Once a fracture extent is selected, the width is calculated as a consequence of technical limitations, (maximum realizable proppant concentration). Knowledge of the leakoff process helps to determine the necessary pumping time and pad volume.

The tip-screenout (TSO) technique has brought a significant change to this design philosophy. Through TSO, fracture width can be increased without increasing the fracture extent. In this context, a strictly technical optimization problem can be formulated: How does one independently select the optimum fracture length and width under a given proppant volume constraint? The problem is one of maximizing the productivity index in the pseudosteady-state flow regime. The answer is of primary importance in understanding frac-and-pack, but is also necessary for understanding hydraulic fracturing in general.

The same propped volume can be used to create a narrow, elongated fracture or a wide, short fracture. It is convenient to select C_{fD} as the decision variable, and then the fracture half-length can be expressed using the propped volume of one wing, $V_f = w_f \times h \times x_f$, as:

$$x_f = \left(\frac{V_f k_f}{C_{fD} h k} \right)^{1/2} \tag{5.55}$$

The productivity index relationship, e.g., the pseudosteady-state expression for oil which follows from Eq. 5.12, after the creation of a fracture of half-length, x_f, can be written as:

$$J = \frac{q}{\bar{p} - p_{wf}} = \frac{2\pi kh}{B\mu\left[\ln\frac{r_e}{r_w} - \frac{3}{4} + \ln\frac{r_w}{x_f} + \left(\ln\frac{x_f}{r_w} + s_f\right)\right]} \tag{5.56}$$

where s_f is the Cinco-Ley et al. pseudoskin appearing because of the fracture, defined by Eq. 5.30. The quantity $\ln x_f/r_w + s_f = -\ln r'_{wD}$ can be obtained from the dimensionless fracture conductivity, C_{fD}, (Fig. 5.1). The wellbore radius drops out and the fracture half-length is substituted from Eq. 5.55. The resulting productivity index is:

$$J = \frac{2\pi kh}{B\mu\left[\ln r_e - \frac{3}{4} + \frac{1}{2}\ln\frac{hk}{V_f k_f} + \frac{1}{2}\ln C_{fD} + \left(\ln\frac{x_f}{r_w} + s_f\right)\right]} \tag{5.57}$$

where the only unknown is C_{fD}. Since the drainage radius, formation thickness, two permeabilities, and the propped volume are fixed, the maximum productivity index occurs when the quantity:

$$y = \frac{1}{2}\ln C_{fD} + \ln\frac{x_f}{r_w} + s_f \tag{5.58}$$

becomes a minimum. The quantity y is shown in Fig. 5.6. Since it depends only on C_{fD}, the optimum $C_{fD,opt} = 1.6$ is a *given constant* for any reservoir, well and proppant. (Note: This value is close to the value 2 which is equal to the intercept of the asymptotes defined by Eqs. 5.33 and 5.34) The optimum dimensionless fracture conductivity corresponds to the best compromise between the capacity of the fracture to conduct and the capacity of the reservoir to deliver hydrocarbon.

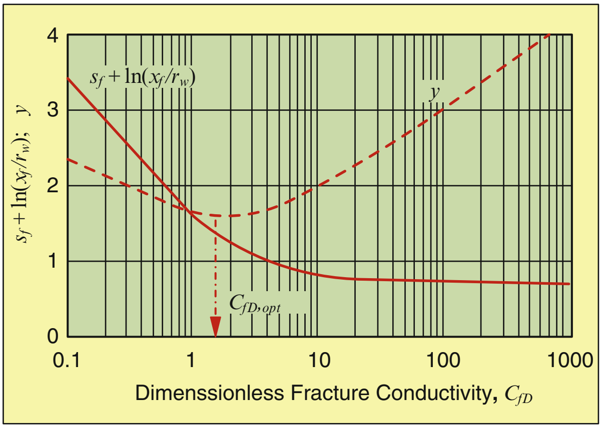


Fig. 5.6 Pseudoskin factor of a vertical well intersected by a finite-conductivity vertical fracture (Cinco-Ley et al. 1978)

5.7.1.2 Technical Optimization

Once the volume of proppant that can be placed into one wing of the fracture, V_f, is known, the optimum fracture half-length can he calculated as:

$$x_f = \left(\frac{V_f k_f}{1.6hk}\right)^{1/2} \tag{5.59}$$

and consequently, the optimum propped average width should be:

$$w = \left(\frac{1.6V_f k}{hk_f}\right)^{1/2} \tag{5.60}$$

These results have several implications. Most important, there is no theoretical difference between low- and high-permeability fracturing. In both cases, a *technically* optimal fracture exists, and it should have a dimensionless fracture conductivity of order unity. In a low-permeability formation, this requirement results in a long and narrow fracture. In high-permeability formations, a short and wide fracture may provide the same dimensionless conductivity. In practice, not all proppant will be placed into the permeable layer, so in the relation above, the *effective* volume should be used, subtracting the proppant placed in the nonproductive layers. It is also important to recognize that the indicated "optimal fracture" may not always be feasible. In high-permeability formations, departure from the optimum dimensionless fracture conductivity might be justified by several factors (e.g. the indicated large width may be impossible to create): a minimum length may he dictated by the damage radius, severe non-Darcy effects in the fracture may strongly reduce the apparent permeability of the proppant pack, and considerable fracture width can be lost because of proppant embedment into the soft formation.

5.7.1.3 Economic Optimization

Having settled the optimization of fracture length vs. width for a fixed proppant volume, the remaining task is to optimize proppant volume. Obviously, this is an economic optimization issue rather than a technical one. The more proppant that is placed in the formation (otherwise optimally), the better the performance of the well. At this point, economic considerations must dominate. The additional revenue at some point becomes marginal compared to the linearly (or even more strongly) increasing costs. This situation is properly treated by applying net present value (NPV) analysis (Balen et al. 1988). Though a NPV analysis always provides an "optimum design," it should not replace the understanding of the underlying technical optimization issues.

5.7.2 Proppant Selection

The primary and unique issue relating to proppant selection for high-permeability fracturing is *proppant sizing*. Proppant strength, shape, composition, and other factors are included in a more general discussion of proppant selection in Chap. 3. Resin-coated proppants are discussed briefly as an emerging frac-and-pack technology at the end of this chapter. While specialty proppants (intermediate-strength and resin-coated proppants) have certainly been used in frac-and-pack treatments, most treatments are pumped with standard graded-mesh sand.

When selecting a proppant size for frac-and-pack, the engineer faces competing priorities: sizing the proppant to address concerns with sand exclusion, or using maximum proppant size to ensure adequate fracture conductivity.

As with equipment choices and fluids selection, the gravel-packing roots of frac-and-pack are also evident when proppant selection is considered. Engineers initially focused on sand exclusion and a gravel pack derived sizing criteria such as that proposed by Saucier (1974). Saucier recommends that the mean gravel size (d_{g50}) be five to six times the mean formation grain size (d_{f50}). The so-called "4-by-8 rule" represents minimum and maximum grain-size diameters that are distributed around Saucier's criteria, i.e. $d_{g\min} = 4d_{g50}$ and $d_{g\max} = 8d_{g50}$, respectively. Thus, many early treatments were pumped with standard 40/60-mesh (0.25–0.42 mm) or even 50/70-mesh (0.21–0.30 mm) sand. The somewhat limited conductivity of these gravel-pack mesh sizes under in-situ formation stresses may not be adequate in many cases. Irrespective of sand mesh size, frac-and-packs tend to reduce concerns with fines migration by reducing fluid flux at the formation face.

The current trend in proppant selection is to use fracturing-size sand. A typical frac-and-pack treatment now uses 20/40-mesh (0.42–0.84 mm) proppant (sand). Maximizing the fracture conductivity can itself help prevent sand production by reducing drawdown. Results with the larger proppant have been encouraging, both in terms of productivity and limiting or eliminating sand production (Hannah et al. 1994).

It is interesting to note that the topics of formation competence and sanding tendency, major issues in the realm of gravel-pack technology, have not been widely studied in the context of frac-and-pack. In many cases, frac-and-pack is providing a viable solution to completion failures *despite* the industry's limited understanding of (soft) rock mechanics.

This move away from gravel-pack practices toward fracturing practices is common to many aspects of frac-and-pack with the exception (so far) of downhole tools, and it seems to justify changing terminology from *frac-pack* to *high-permeability fracturing*. The following discussion of fluid selection is also consistent with this perspective.

5.7.3 Fluid Selection

Fluid selection for frac-and-pack has always been driven by concerns with damaging the high-permeability formation, either by filter-cake buildup or (especially) polymer invasion. Most early treatments were performed with HEC, the classic gravel-pack fluid, because it was perceived to be less damaging than guar-based fracturing fluids. While the debate continues and many operators continue to use HEC fluids, the fluid of choice is increasingly borate-crosslinked HPG.

Based on a synthesis of reported findings from several practitioners, Aggour and Economides (1996) provide a well-reasoned rationale to guide fluid selection in frac-and-pack. Their findings suggest that if the extent of fracturing fluid invasion is minimized, the degree of damage (permeability impairment caused by filter-cake or polymer invasion) is of secondary importance. They use the effective skin representation of Mathur et al. (1995) to show that if fluid leakoff penetration is small, even severe permeability impairments can be tolerated without exhibiting positive skin effects. In this case, the obvious recommendation in frac-and-pack is to use high-polymer concentration, crosslinked fracturing fluids with fluid-loss additives, and an aggressive breaker schedule. The polymer, crosslinker, and fluid-loss additives limit polymer invasion, and the breaker ensures maximum fracture conductivity, a critical factor which cannot be overlooked. Experimental work corroborates these contentions.

Linear gels have been known to penetrate cores of very low permeability (1 md or less) whereas crosslinked polymers are likely to build filter cakes at permeabilities two orders of magnitude higher (Roodhart 1985; Mayerhofer et al. 1991). Filter cakes, while they may damage the fracture face, clearly reduce the extent of polymer penetration into the reservoir that is normal to the fracture face. At extremely high permeabilities, even crosslinked polymer solutions may invade the formation.

Cinco-Ley and Samaniego-V. (1981b) and Cinco-Ley et al. (1978) described the performance of finite-conductivity fractures and delineated the following three major types of damage affecting this performance:

- *Reduction of proppant-pack permeability* resulting from either proppant crushing or (especially) unbroken polymer chains, leads to fracture conductivity impairment. This condition can be particularly problematic in moderate- to high-permeability reservoirs. Extensive progress in breaker technology has dramatically reduced concerns with this type of damage.
- *Choke damage* refers to the near-well zone of the fracture that can be accounted for by a skin effect. This damage can result from either overdisplacement at the end of a treatment or by fines migration (native or proppant) during production and the accumulation of fines near the well but within the fracture.
- *Fracture-face damage* implies permeability reduction normal to the fracture face and includes permeability impairments caused by the filter cake, polymer-invaded zone, and filter cake-invaded zone.

Mathematical expressions and correlations for skin factors resulting from these three types of damage are already given in Sect. 5.3.

McGowen et al. (1993) presented a series of experiments showing the extent of fracturing fluid penetration in cores of various permeabilities. Fracturing fluids used were 70-lb/Mgal (8.4 kg/m^3) HEC and 30- or 40-lb/Mgal (3.6 or 4.8 kg/m^3) borate-crosslinked HPG. Filtrate volumes were measured in mL/cm^2 of leakoff area (centimeters of penetration) for a 10-md limestone ($k \approx 10 \times 10^{-3}$ μm^2) and

200- and 1,000-md sandstones ($k \approx 200 \times 10^{-3}$ μm^2 and $k \approx 1{,}000 \times 10^{-3}$ μm^2) at 120°F, 180°F and 240°F (49°C, 82°C and 115°C).

Several conclusions are drawn from this work:

- Crosslinked fracturing fluids are far superior to linear gels in controlling fluid leakoff in high-permeability rock. For example, 40-lb/Mgal (4.8 kg/m^3) borate-crosslinked HPG greatly outperforms 70-lb/Mgal (8.4 kg/m^3) HEC in a 200-md ($k = 200 \times 10^{-3}$ μm^2) core at 180°F (82°C).
- Linear gel performs satisfactorily in 10-md ($k = 10 \times 10^{-3}$ μm^2) rock but fails dramatically at 200 md ($k = 200 \times 10^{-3}$ μm^2). Even aggressive use of fluid-loss additives (40-lb/Mgal; 4.8 kg/m^3 silica flour) does not appreciably alter the leakoff performance of HEC in a 200-md ($k = 200 \times 10^{-3}$ μm^2) core.
- Increasing crosslinked gel concentrations from 30- to 40-lb/Mgal (3.6–4.8 kg/m^3) has a major impact on reducing leakoff in 200-md ($k = 200 \times 10^{-3}$ μm^2) core. Crosslinked borate maintains excellent fluid-loss control in 200-md ($k = 200 \times 10^{-3}$ μm^2) sandstone and performs satisfactorily even at 1,000 md ($k = 1{,}000 \times 10^{-3}$ μm^2).

This experimental work strongly corroborates the modeling results of Aggour and Economides (1996) and suggests the use of higher-concentration crosslinked polymer fluids with, of course, an appropriately designed breaker system.

HEC and borate-crosslinked HPG fluids are the dominant fluids currently used in frac-and-pack; however, a third class of fluid deserves to be mentioned, so-called viscoelastic surfactant (VES) fluids. There is little debate that these fluids exhibit excellent rheological properties and are nondamaging, even in high-permeability formations. The advantage of VES fluids is that they do not require the use of chemical breaker additives; the viscosity of this fluid conveniently breaks (leaving considerably less residue than polymer-based fluids) either when it contacts formation oil or condensate, or when its salt concentration is reduced. Brown et al. (1996) present typical VES fluid performance data and case histories.

The vulnerability of VES fluids is in their temperature limitations. The maximum application temperature for VES fluids has only recently been extended from 55°C to 95°C.

5.8 Fracture Design Simulators

The purpose of a fracture design simulator is to use a computer to simulate, as closely as possible, the actual downhole events that occur while performing a fracturing treatment. Simulation allows design iterations, if necessary, to optimize the treatment design before starting expensive field operations. A number of reliable fracture design simulators are currently available for TSO and frac-and-pack design. One of the major fracture design simulators is MFrac, developed by Meyer & Associates, Inc. The frac-and-pack methodology presented here were originally developed and implemented into MFrac-IIa ver. 7.1 July of 1994. An analytical form of this methodology was presented at the 1995 SPE annual meeting (Fan and Economides 1995a).

This section presents in a concise manner a summary of Meyer & Associates, Inc. tech notes for design of TSOs and frac-and-packs.

5.8.1 Methodology

MFrac uses numerical, state-of-the-art, frac-and-pack and TSO methodologies to design "fully packed" or TSO type proppant distributions. The modeling techniques used require that the fracture propagation and proppant transport solution be linked in such a way that each can influence the other. Normally, this means that for each time step in the fracture propagation calculation, the proppant transport simulation must be assessed and coupled. This methodology differs substantially from a conventional fracture stimulation approach which by design tries to prevent proppant screen-outs or bridging.

In order to fully pack a fracture and achieve a desired conductivity, it is necessary to accurately model and control the rate of creation of fracture volume. If this is accomplished, the fracture can be filled or packed with an injection concentration far below the packed value.

For a frac-and-pack or TSO design the slurry treatment must be scheduled such that as the earlier stages concentrate, due to slurry dehydration or leakoff, the later stages fill the void created by a continuous and declining rate of fluid loss. The only operational alternatives to fully pack a fracture is to either decrease the injection rate or increase the proppant concentration to offset the decreased leakoff rate during the frac-and-pack process. Increasing the leakoff velocity (rate) during the frac-and-pack process will also enable the fracture to be fully packed. However, accomplishing this in a diffusion controlled environment may be unrealistic. In practice, the maximum pumped concentration is normally limited by an upper constrained value far below the packed concentration needed for frac-and-packs. Therefore, the only practical way to accomplish a frac-and-pack reliably is to decrease the injection rate after pre-specified design criteria is satisfied to offset the decline in fluid loss once screen-out occurs and fracture growth has stopped. The advantage of decreasing the injection rate also minimizes excess "ballooning" by maintaining a constant fracture pressure. This methodology is easily implemented in the field (by controlling pressure and decreasing rate) and can help force a TSO or enhance the rate of frac-packing.

5.8.2 Design Criteria

The criteria for automatic TSO and frac-and-pack designs include:

- Designing to a pre-specified fracture length to optimized near wellbore conductivity;
- Basing the design on a maximum allowable inlet concentration;
- Designing to achieve a minimum concentration per unit area; and
- Maintaining pumping pressures below a critical maximum.

5.8.3 Procedures

In terms of procedures, operations should design for a target fracture length. After a perimeter tip-screenout is achieved, fracture extension (length and height growth) will stop and the fracture width and pressure will begin to increase. The rate of fluid leakoff begins to decrease.

For a TSO, the fracture pressure is allowed to continue increasing until the minimum concentration per unit area is satisfied or the pressure rises to the maximum allowable value. The TSO methodology assumes a constant injection rate during the entire pumping schedule.

For a frac-and-pack once the fracture width (or pressure) reaches a value to satisfy the minimum concentration per unit area at the bank concentration, the fracture pressure (compliance) is held constant by decreasing the injection rate to match the leakoff rate.

Because excess ballooning is permitted in a TSO, the inlet concentrations to approach a “fully” packed fracture are not feasible.

Figure 5.7 illustrates the methodologies for tip-screenout and frac-pack designs. As shown, the behavior of the fracture length (extension) is similar for both methods with arresting of fracture propagation after the time of tip-screenout (TSO). The inlet proppant concentration for a TSO is shown to continually increase with time (after the initial TSO stage) until it reaches a maximum pre-specified inlet concentration.

The frac-and-pack schedule shows a similar behavior up to the time of the maximum inlet concentration. After reaching maximum concentration, the injection rate is decreased to match the leakoff rate while maintaining a constant inlet concentration. The leakoff rate decreases as a result of the decreased fracture propagation rate. Since no new fracture area is being created during the packing process, the leakoff velocity will decrease with time as a result of diffusion. If leakoff is not controlled by diffusion or is time dependent, the leakoff rate will decline at a different slope.

For a frac-and-pack, once the injection rate is cut to the leakoff rate, the fracture pressure will remain essentially constant. This mitigates the pressure dependence effect on fluid loss. If leakoff is a strong function of fracture pressure, the leakoff coefficient would change more drastically for a TSO than a frac-and-pack because of the continued increasing net fracture pressure with time after a TSO.

Figure 5.7 shows that the fracture net pressure and width both increase with time after a TSO. However, the frac-and-pack net pressure and width remain constant after the time the maximum concentration is reached. Since this 3-D model is not a lumped model, the spatial compliance factors may change during the declining injection rate period resulting in slight variations in the pressure and aperture. The fracture volume will, however, remain constant during this period. Figure 5.7 also shows the final concentration at the end of the job (EOJ). This clearly illustrates that the main advantage of packing a fracture all the way back to the wellbore is to increase the propped width and minimize excess pressure.

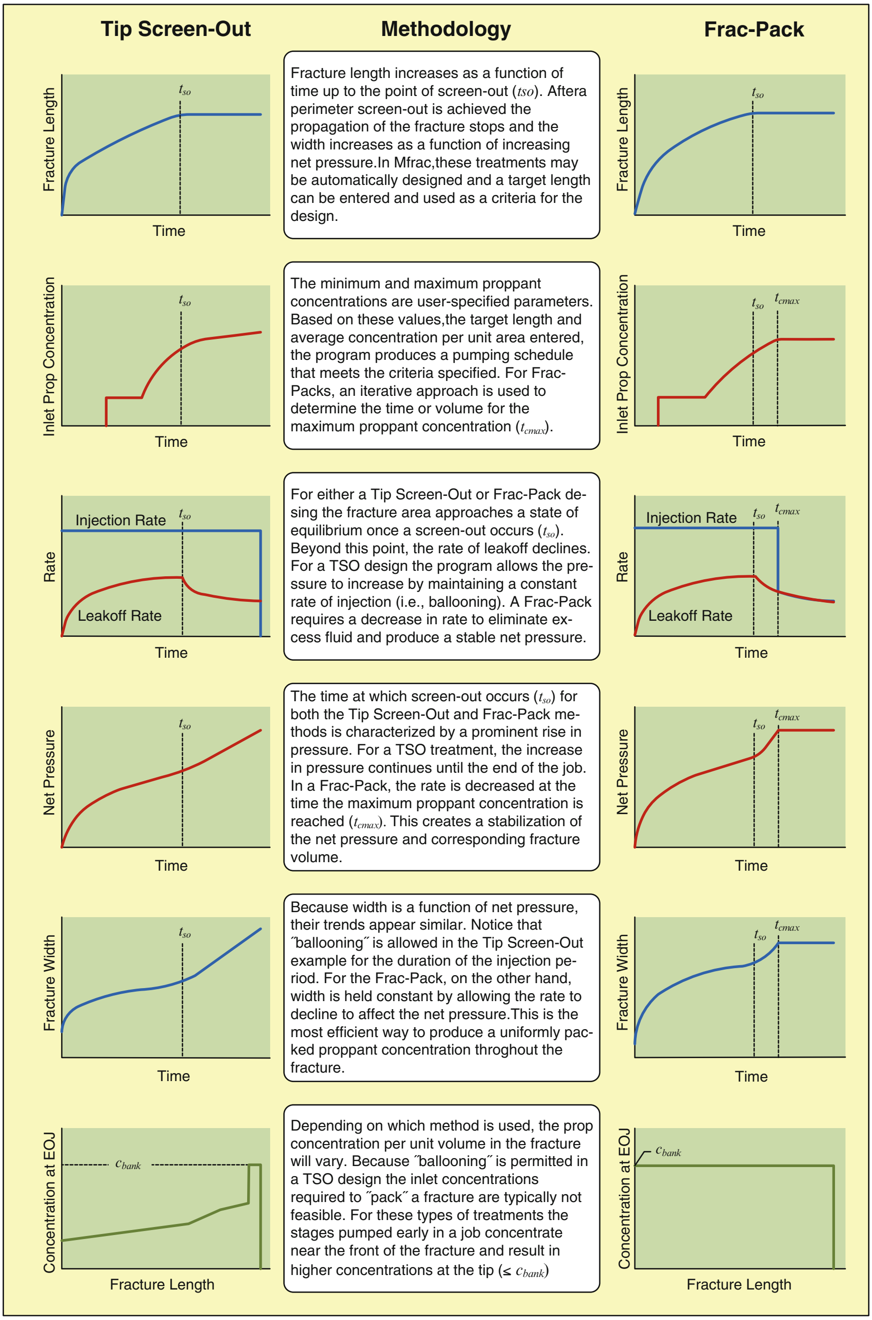


Fig. 5.7 Tip-screenout vs. frac-and-pack methodology (Meyer User's Guide 2010)

Generally, frac-and-packs are performed in formations which have higher permeability and lower fracture efficiencies than TSOs. Therefore, to achieve an adequate dimensionless conductivity, C_{fD}, the fracture conductivity, $k_f w_f$, must be greater for frac-and-packs. This is achieved by designing for short high conductivity fractures. Frac-and-packs are also most easily realized in formations conducive to low fracture efficiencies (typically less than 40%). The lower the efficiency the easier and quicker it is to achieve a TSO or frac-and-pack. For fracture efficiencies greater than 50% it is difficult to perform a classical "fully packed" fracture. Other important considerations are the minimum allowable flow rate, proppant settling, time/pressure dependent leakoff, spurt loss and changing fracture compliance. The numerical procedure developed here for 3-D (and 2-D) TSOs and frac-and-pack automatically accounts for these effects and other time dependent parameters generally ignored in analytical solutions.

Typically, TSOs are performed in moderate permeability "hard" rock formations whereas frac-and-packs have been successfully performed in high permeability unconsolidated "soft" rock formations. The advantage of a successful frac-and-pack is that the fracture will be packed at the settled bank proppant concentration and at the dynamic pumped width. The propped width ratio for a TSO (no settling) will be equal to the ratio of the slurry concentration in the fracture at the end of pumping divided by the settled bank slurry concentration ($w_p / w_{eoj} = c_s / c_s|_{bank}$). If 20/40-mesh (0.42–0.84 mm) Jordan sand is placed at a maximum proppant concentration of 1,440 kg/m^3 (940 kg/m^3 slurry) the TSO propped width ratio would be 0.61 (i.e., bank concentration of 3,650 kg/m^3 liquid (1,530 kg/m^3 slurry), where $c_l = c_s / (1 - c_s / \rho_p)$ or $c_s = c_l / (1 + c_l / \rho_p)$. This clearly illustrates why many TSOs are ballooned to a much greater extent than necessary to achieve the same concentration per unit area as a frac-and-pack.

5.8.4 Numerical Simulation

The above methodology for frac-and-packs and TSOs was implemented in 3-D hydraulic fracturing simulator (MFrac) in early 1994. The code was beta tested and released in late summer. This methodology is applicable for all types of 2-D and 3-D type fracture geometry models. The methodology is simple and based on sound engineering principles of mass and momentum conservation. Since this methodology has been incorporated in a numerical simulator, implementation of different boundary conditions or assumptions is possible and the effect of such changes quantified. Although all the underlying boundary conditions outlined in this methodology may not always be satisfied, these tools enable the design engineer to investigate the simplicity of this first order analysis and how substantially it deviates from conventional fracturing.

To illustrate the frac-and-pack methodology an automatic design was numerically simulated based on the following criteria:

- Pre-specified fracture length of 25 m
- Maximum allowable inlet concentration of 1,200 kg/m^3 liquid
- Designed to achieve a concentration per unit area of 30 kg/m^2
- Maintain a pumping pressure below 800 bars

Summary report with input data of this simulation is given in Table 5.1. Main treatment parameters and resulting fracture geometry are shown in Figs. 5.8 and 5.9.

Figure 5.10 shows the inlet slurry and resulting leakoff rate as a function of time which satisfy the pre-specified frac-and-pack criteria. Figure 5.11 illustrates the simulated automated inlet proppant concentration schedule.

Once the design fracture length is achieved at about 14 min fracture extension (length and height) stops as a result of the tip-screenout condition (Fig. 5.12). The fracture continues to balloon from 14 to 27.5 min to a width of about 37 mm (Fig. 5.13) to meet the design concentration/area of about 30 kg/m^2 for a fully packed fracture.

Once the fracture stops propagating the pressure and width continue increasing (Fig. 5.13). After the optimum design width is achieved the injection rate is cut to meet the leakoff rate and the inlet concentration is maintained at the maximum value. This stops the fracture from ballooning, resulting in an approximate constant pressure throughout the remainder of the job.

Figure 5.10 shows that once the fracture stops propagating the leakoff rate decreases. Also, the liquid rate decreases with increasing inlet sand concentration. After the slurry rate decreases to the leakoff rate the liquid injection rate falls below the leakoff rate. The higher the maximum allowable inlet concentration the lower the liquid rate will be.

Figure 5.14 shows the behavior of fracture efficiency as a function of time. After the propagation rate diminishes at 14 min the efficiency rises as a result of the decreased leakoff rate. However, once the injection rate decreases to the leakoff rate the fracture volume remains approximately constant (i.e., the compliance factor may, however, change slightly with time) and the efficiency will continue decreasing until the fracture is fully packed. The fracture efficiency at closure represents the fraction of propped volume to total injected slurry volume.

Figure 5.15 shows the final fully packed fracture concentration per unit area contours. This profile is shown to match the desired final value of about 30 kg/m^2. Profiles of average propped width at the end of job (EOJ) and after fracture closure are shown in Fig. 5.16. Figure 5.17 shows the resulting fracture conductivity contours, while Fig. 5.18 shows profile of average fracture conductivity in pay zone.

Figures 5.10, 5.11, 5.12, 5.13, 5.14, 5.15, 5.16, 5.17 and 5.18 illustrate the frac-and-pack methodology as implemented in 3-D hydraulic fracturing simulator. The advantage of using a numerical simulator is that the leakoff rate, compliance factors, spurt loss, height growth and other typical simplifying analytical assumptions made by 2-D models are not necessary to solve the governing equations.

Table 5.1 Simulation summary report with input data

Input data

Rock properties

Zone name	TVD at bottom (m)	MD at bottom (m)	Stress gradient (bar/m)	Stress (bar)	Young's modulus (GPa)	Poisson's ratio	Fracture toughness (MPa·m$^{1/2}$)	Critical stress (bar)	Stress interpolation
Shale	3,088.3	3,603	0.18	555.9	3.5	0.35	1.5	0	Off
Sand	3,102	3,623	0.165	511.84	2	0.3	1.5	0	Off
Shale	3,124.2		0.18	562.36	3.5	0.35	1.5	0	Off

Fluid loss data

Zone name	TVD at bottom (m)	MD at bottom (m)	Leakoff coeff. (cm/min$^{1/2}$)	Spurt loss (m^3/m^2)
Shale	3,088.3	3,603	0	0
Sand	3,102	3,623	0.4	0
Shale	3,124.2		0	0

Wellbore hydraulics data

Wellbore volume	32.152	(m^3)
Injection down	Tubing	
Horizontal well	Off	
Surface line volume	0.75708	(m^3)
Wellbore volume reference MD	3,604.6	(m)
Wellbore volume reference TVD	3,089.7	(m)
Maximum BHTP	6,894.8	(bar)
Frac-pack screen:		
Screen OD	81.28	(mm)
Cross-over valve loss coefficient	1	

Perforation zones

	Active	Zone	Top of perfs TVD (m)	Bottom of perfs TVD (m)	Top of perfs MD (m)	Bottom of perfs MD (m)
1.	Yes	Sand	3,088.3	3,102	3,603	3,623

Zone data

	Zone	No. of multiple fractures	Pay zone from (m)	To (m)	Perm. (mD)	Perforations number	Diameter (mm)
1.	Sand	1	3,088.2	3,102.3	200	864	20.32

Input bottomhole treatment schedule

Schedule type	Bottomhole	
Flush fluid type	FLD7	
Recirculation volume	0	(m^3)

Stage no.	Slurry rate (m^3/min)	Stage liquid volume (m^3)	Stage time (min)	Stage type	Fluid type	Prop type	Prop conc. (kg/m^3)	Prop damage factor
1	2.4	25.324	10.551	Pad	FLD7	C002	0	0.5
2	2.4	7.1655	3.253	Prop	FLD7	C002	240	0.5
3	2.4	2.273	1.0319	Prop	FLD7	C002	240	0.5
4	2.4	2.8547	1.4025	Prop	FLD7	C002	480	0.5
5	2.4	3.3226	1.7564	Prop	FLD7	C002	720	0.5
6	2.29	3.7724	2.2374	Prop	FLD7	C002	960	0.5
7	2.12	1.8573	1.2684	Prop	FLD7	C002	1,200	0.5
8	1.81	3.2559	2.6043	Prop	FLD7	C002	1,200	0.5
9	1.23	2.216	2.6083	Prop	FLD7	C002	1,200	0.5
10	0.5	0.80605	2.3339	Prop	FLD7	C002	1,200	0.5

Fluid type: FLD7 – Sample fluid 7	84.999	(m^3)
Proppant type: C002 – 20/40 EconoProp	19,412	(kg)

Table 5.1 (continued)

Output data

Bottomhole treatment schedule pumped

Stage no.	Avg slurry rate (m^3/min)	Liquid volume (m^3)	Slurry volume (m^3)	Total slurry volume (m^3)	Total time (min)	Fluid type	Prop type	Conc. from (kg/m^3)	Conc. to (kg/m^3)	Prop. stage mass (kg)
1	2.4	25.324	25.324	25.324	10.551	FLD7	0000	0	0	0
2	2.4	7.1655	7.8072	33.131	13.804	FLD7	C002	240	240	1,719.7
3	2.4	2.273	2.4766	35.607	14.836	FLD7	C002	240	240	545.53
4	2.4	2.8547	3.366	38.973	16.239	FLD7	C002	480	480	1,370.3
5	2.4	3.3226	4.2152	43.189	17.995	FLD7	C002	720	720	2,392.3
6	2.29	3.7724	5.1236	48.312	20.233	FLD7	C002	960	960	3,621.5
7	2.12	1.8573	2.689	51.001	21.501	FLD7	C002	1,200	1,200	2,228.8
8	1.81	3.2559	4.7137	55.715	24.105	FLD7	C002	1,200	1,200	3,907.1
9	1.23	2.216	3.2083	58.923	26.714	FLD7	C002	1,200	1,200	2,659.2
10	0.5	0.60438	0.875	59.798	28.464	FLD7	C002	1,200	1,200	725.26

Total slurry volume	59.798	(m^3)
Total liquid volume	52.645	(m^3)
Total proppant mass	19,170	(kg)

Fracture propagation solution

(Calculated values at end of treatment)

	Sand	
Slurry volume injected	59.798	(m^3)
Liquid volume injected	52.646	(m^3)
Fluid loss volume	47.174	(m^3)
Frac fluid efficiency	0.21111	
Net frac pressure	30.298	(bar)
Length (one wing)	26.146	(m)
Upper frac height	7.2863	(m)
Lower frac height	7.1268	(m)
Upper frac height (TVD)	3087.9	(m)
Lower frac height (TVD)	3102.4	(m)
Total frac height	14.413	(m)
Max. frac width at perfs	34.155	(mm)
Avg. hydraulic frac width	20.516	(mm)

Proppant design summary

	Sand	
Frac length – Created	26.146	(m)
Frac length – Propped	26.122	(m)
Frac height – Avg.	11.763	(m)
Propped height (pay zone) – Avg.	11.743	(m)
Max width at perfs – EOJ	34.155	(mm)
Propped width (Well) – Avg.	25.138	(mm)
Propped width (pay zone) – Avg.	16.529	(mm)
Conc./area (Frac) – Avg. at EOJ	31.152	(kg/m^2)
Conc./area (pay zone) – Avg. at closure	26.589	(kg/m^2)
Frac conductivity (pay zone) – Avg. at closure	2,621	(mD·m)
Dimensionless frac conductivity (pay zone)	0.5017	
Beta	0	(1/m)
Avg. fracture permeability	158.81	(darcy)
Propped fracture ratio (EOJ)	1.0099	
Closure time	0	(min)
Screen-out time	13.929	(min)

Table 5.1 (continued)

Proppant transport summary table

End of job							After closure			
Stage no.	Interval from (m)	Interval to (m)	Height slurry (m)	Height bank (m)	Conc. inlet (kg/m^3)	Conc. final (kg/m^3)	Prop width (mm)	Prop Ht. total (m)	Prop Ht. pay (m)	Conc. area (kg/m^2)
10	0	2.0724	14.282	$7.3e^{-06}$	1,200	3,424.8	24.871	14.282	14.016	40.381
9	2.0724	5.8436	13.888	$7.5e^{-06}$	1,200	3,424.8	24.017	13.888	13.836	38.994
8	5.8436	10.071	13.279	$7.6e^{-06}$	1,200	3,424.8	22.57	13.279	13.279	36.645
7	10.071	12.442	12.695	$7.1e^{-06}$	1,199.8	3,424.8	21.096	12.695	12.695	34.251
6	12.442	16.55	12.007	$7.5e^{-06}$	959.83	3,424.8	19.296	12.007	12.007	31.329
5	16.55	19.628	11.05	$7.4e^{-06}$	719.83	3,424.8	16.776	11.05	11.05	27.237
4	19.628	21.644	10.139	$2.2e^{-06}$	479.83	3,424.8	14.434	10.139	10.139	23.435
3	21.644	22.534	9.47	$1.0e^{-06}$	240	3,424.8	12.777	9.47	9.47	20.745
2	22.534	26.145	7.5129	$1.8e^{-08}$	239.87	3,424.8	8.6484	7.5129	7.5129	14.041
1	26.145	26.146	1.4995	0	0	3,424.8	0.79182	1.4995	1.4995	1.2856

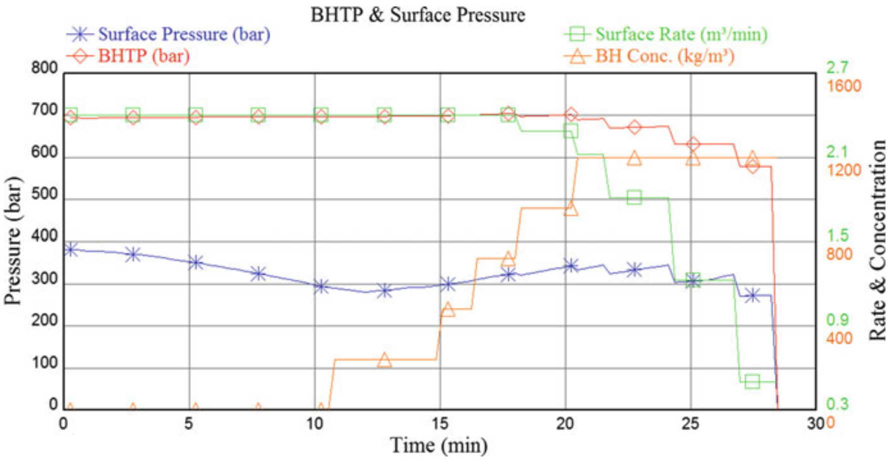


Fig. 5.8 Main treatment parameters

5.8.5 Results and Conclusions

The methodology and procedures outlined in Fig. 5.7 will help the design engineer better understand TSO and frac-and-pack treatments. The advantage of a frac-and-pack, in controlling the pressure rise to minimize excess "ballooning" and in optimizing proppant placement, was also demonstrated. The application for either the TSO or frac-and-pack is more a function of the fracture efficiency than if it is of "hard" or "soft" rock. Lower fracture efficiencies (high reservoir permeability) favor the frac-and-pack while higher efficiencies (moderate permeability) favor the TSO methodology. Excessive leakoff control for both the TSO and frac-and-pack may be a strong disadvantage resulting in higher fracture efficiency jobs.

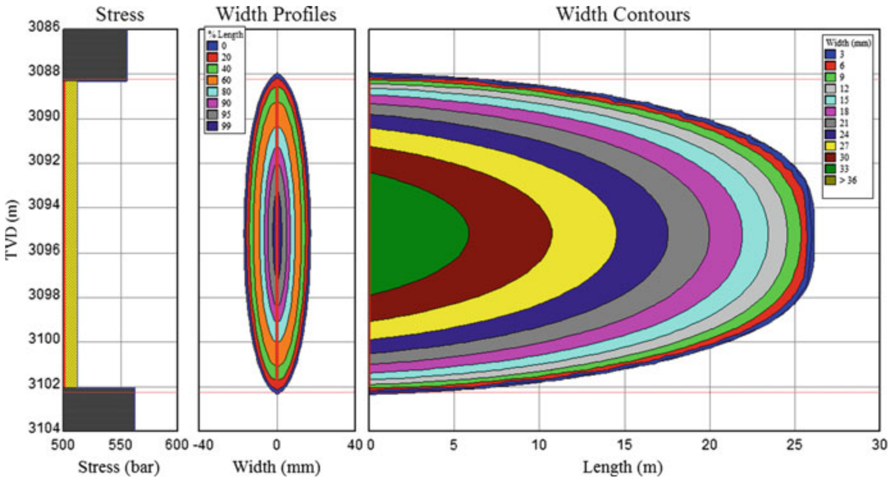


Fig. 5.9 Created fracture geometry

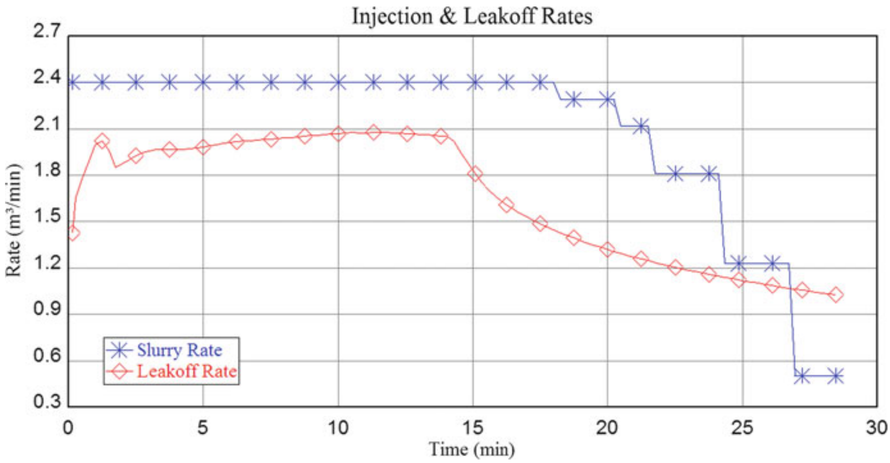


Fig. 5.10 Automated injection and leakoff rates vs. time

High permeability reservoirs require high conductivity fractures, hence the term "packed" is applied since the fracture must be fully packed with proppant to accomplish an optimum conductivity. To approach a truly "packed" condition it is necessary to control the injection rate and inlet proppant concentration once a TSO has occurred and throughout the frac-and-pack process.

When classical TSO methods are applied to small scale treatments undesirable or less desirable effects may occur due to the resulting proppant distribution. Normally, frac-and-packs are performed in high permeability reservoirs that require

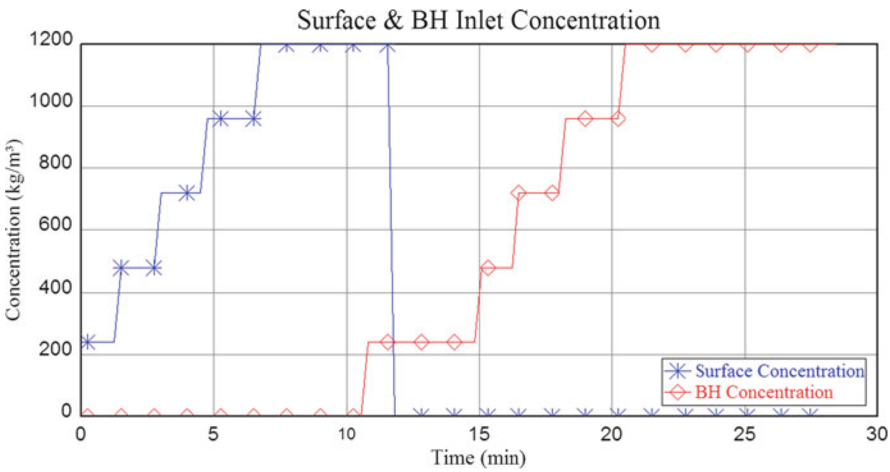


Fig. 5.11 Automated inlet proppant concentration vs. time

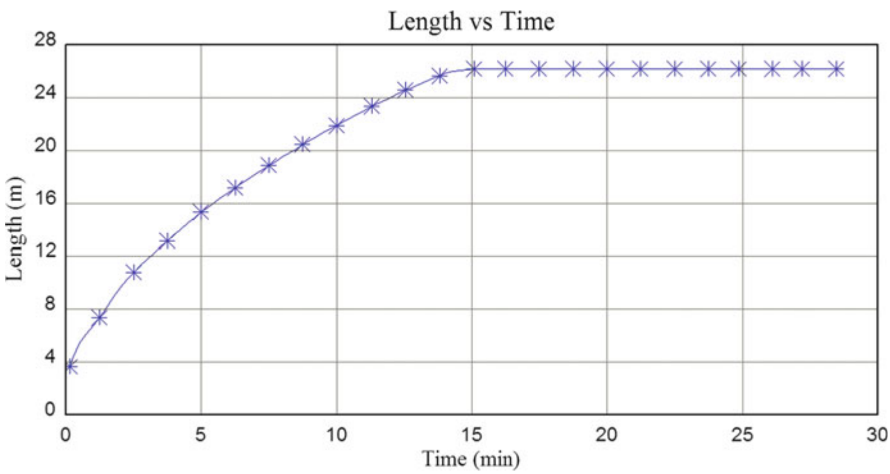


Fig. 5.12 Fracture extension vs. time

a more aggressive approach to achieve the optimum proppant placement for full development of short high conductivity fractures.

Achieving the optimum condition described in the methodology above requires an understanding of the fundamental dynamic time dependent diffusion fluid loss process for a specific application. Fracture growth equilibrium can then be inferred by considering the material balance between injection, fluid loss and overall fracture conservation of volume (mass).

Frac-and-packs are most applicable in design of hydraulic fracturing treatments when the target conductivity is high and more control in the spatial distribution of proppant is required.

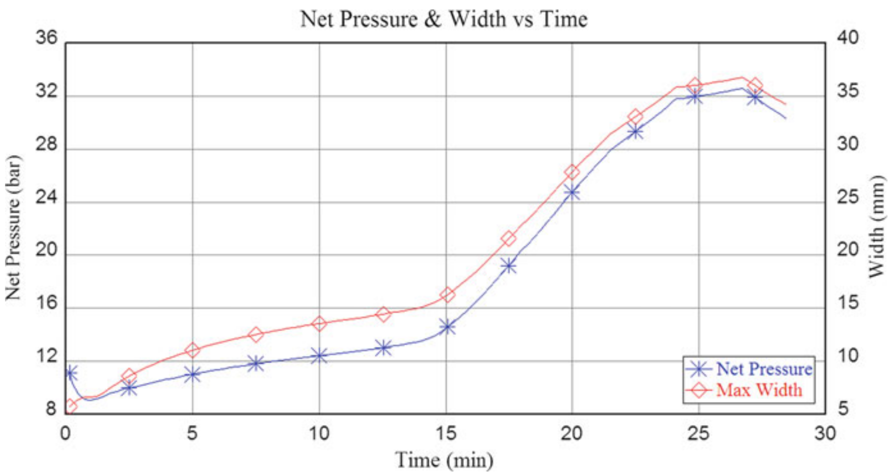


Fig. 5.13 Fracture net pressure and width vs. time

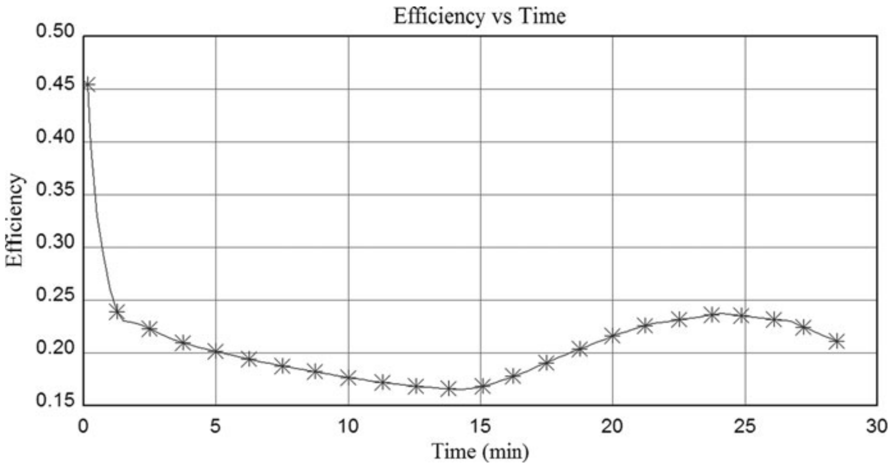


Fig. 5.14 Fracture efficiency vs. time

5.9 Evaluation of Frac-and-Pack Treatments

5.9.1 Production Results

The evaluation of frac-and-pack treatments can be viewed on several different levels. Economic justification (production results) is the first level on which frac-and-pack technology was (and continues to be) evaluated. Simply put, frac-and-pack has gained widespread acceptance because it allows operators to produce more oil at less cost.

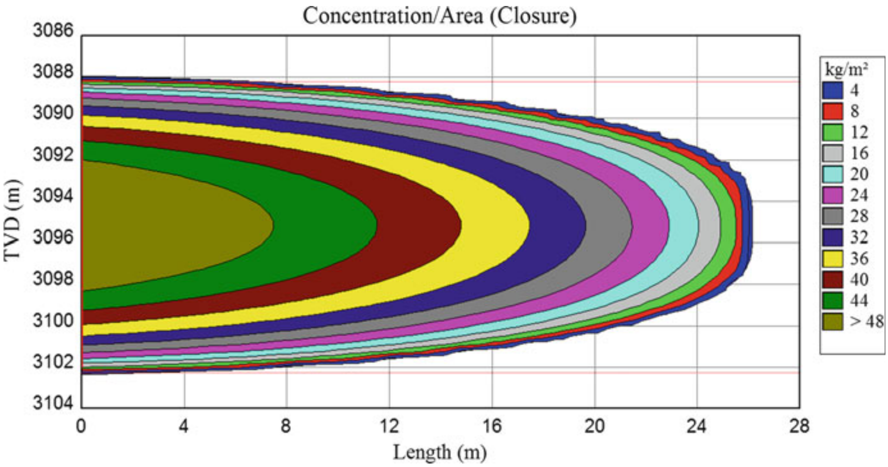


Fig. 5.15 Proppant concentration per unit area contours

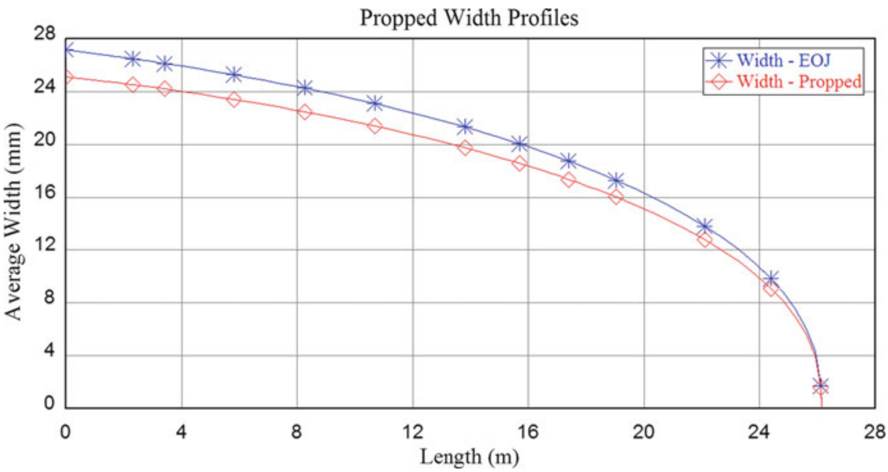


Fig. 5.16 Propped fracture width profiles

McLarty and DeBonis (1995) report that frac-and-pack treatments typically result in production increases 2–2.5 times that of comparable gravel packs. Similar reports of production increase are scattered throughout the body of frac-and-pack literature. Stewart et al. (1995) present a relatively comprehensive economic justification for frac-and-pack that considers (in addition to productivity improvements) the incremental cost of frac-and-pack treatments and the associated payouts, operating expenses, relative decline rates, and reserve recovery acceleration issues.

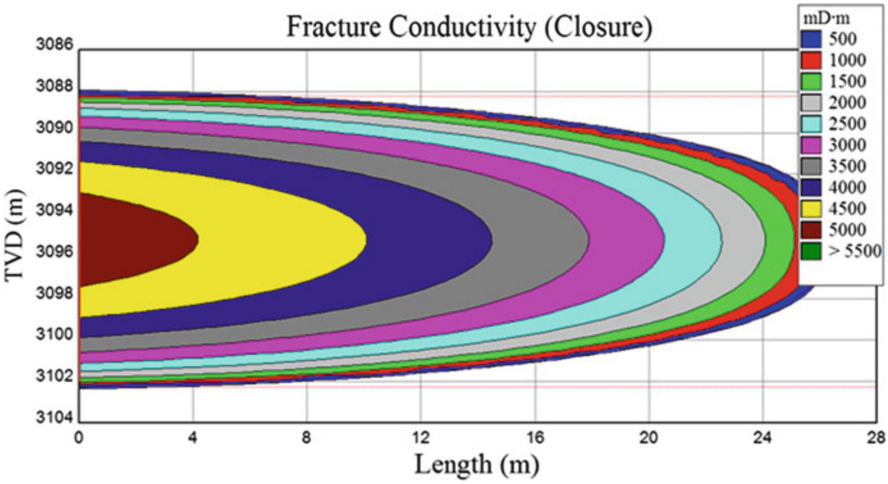


Fig. 5.17 Fracture conductivity contours

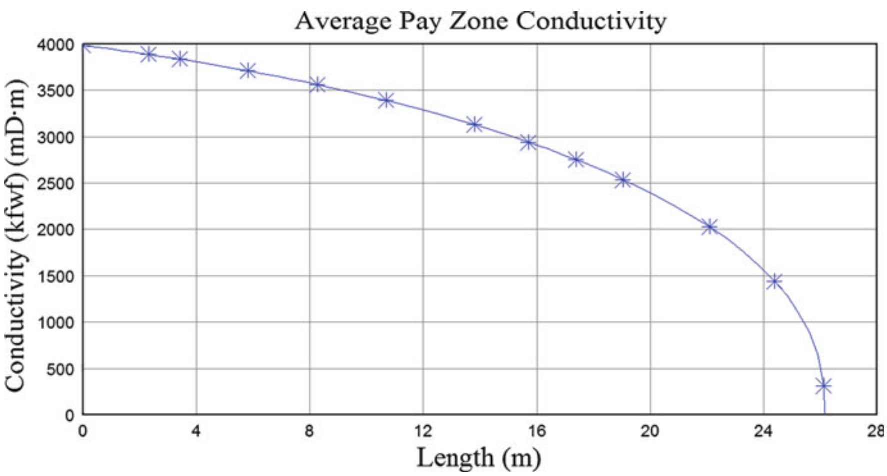


Fig. 5.18 Average pay zone conductivity

5.9.2 Evaluation of Real-Time Treatment Data

There is increasing recognition of the value of real-time frac-and-pack treatment data. Complete treatment records and digital treatment datasets are now routinely collected and evaluated as part of post-treatment analysis. Treatment reconstruction and post-mortem diagnosis hold tremendous potential to improve frac-and-pack design and execution, but the usefulness of many ongoing efforts in this regard is limited. A popular approach to evaluation of real-time datasets (pretreatment and main treatment) is net-pressure history-matching, although this approach is not advocated.

The incorporation of multiple leakoff, stress, friction and other variables in a 3D simulator, while it may (and invariably does) lead to an excellent "match," unfortunately sacrifices the uniqueness (usefulness) of the evaluation by introducing multiple degrees of freedom. These activities may provide operators with qualitative direction on a case-by-case basis, but they also conceal the real issues and retard fundamental development of the technology.

In contrast to this approach, consider the step-wise approach for the evaluation of bottomhole treating pressures outlined by Valko et al. (1996):

- A leakoff coefficient is determined from an evaluation of minifrac data using a minimum number of assumptions, minimum input data, and minimum user interaction. Radial fracture geometry and a combined Nolte-Shlyapobersky (Shlyapobersky et al. 1988) method are suggested.
- When the obtained leakoff coefficient is used, an almost automatic procedure is suggested to estimate the created fracture dimensions and the areal proppant concentration from the bottomhole-pressure curve monitored during the execution of the frac-and-pack treatment. This procedure is termed as "slopes analysis".
- The obtained fracture dimensions and areal proppant concentration can be converted into an equivalent fracture extent and conductivity. The actual performance of the well is analyzed on the basis of well-test procedures, and these results arc compared to the results of the slopes analysis.

Conducting the procedure above for a large number of treatments originating from various operators will result in a data bank that ultimately improves the predictability and outcome of frac-and-pack treatments.

At present, there seems to be a trend in the industry to support joint efforts and assist mutual exchange of information. The procedure above provides a coherent (though not exclusive) framework to compare frac-and-pack data from various sources through the use of a common, cost-effective evaluation methodology.

5.9.3 Post-treatment Pressure-Transient Analysis

For post-treatment evaluation, temperature logs and various fracture-mapping techniques, such as triaxial borehole seismic and radioactive tracer mapping, have gained increasing importance. However, from the basis of future production, by far the most important evaluation is pressure transient analysis. While avoiding an exhaustive treatment of the subject, it is appropriate at this juncture to discuss several issues related to pressure-transient analysis in frac-and-pack wells, especially positive skin factors, which pose the largest challenge to treatment evaluation.

The performance of a vertically fractured well under pseudosteady-state flow conditions was investigated by McGuire and Sikora (1960) through the use of a physical analog (electric current). A similar study for gas wells was conducted by van Poolen et al. (1958). For the "unsteady-state" case, a whole series of works was initiated by Gringarten and Ramey (1974), and continued by Cinco-Ley et al. (1978). They clarified concepts of the infinite-conductivity fracture, uniform-flux fracture, and finite-conductivity fracture. From the formation perspective, double-porosity reservoirs, multilayered reservoirs, and several different boundary geometries have been considered. The typical flow regimes (fracture linear, bilinear, pseudoradial) have been well documented in the literature. Deviations from ideality (non-Darcy effects) have also been considered.

Post-treatment pressure transient analysis for frac-and-packed wells starts with a log-log diagnostic plot that includes the pressure derivative. Once the different flow regimes are identified, specialized plots can be used to obtain the characteristics of the created fracture. In principle, fracture length and or conductivity can be determined using the prior knowledge of permeability. For frac-and-pack, however, the relatively large arsenal of pressure-transient diagnostics and analysis for fractured wells has proven somewhat ineffective. Often, it is difficult to reveal the marked characteristics of an existing fracture on the diagnostic plot. In fact, the well often behaves similar to a slightly damaged, unstimulated well. A frac-and-pack treatment is often considered successful if a large positive skin of order +10 or more is decreased to the range of +1 to +4. These (still) positive skin factors create the largest challenge of treatment evaluation.

The obvious discrepancy between theory and practice has been attributed to several factors, some of which are well documented and understood and some others of which are still in the form of hypotheses.

5.9.3.1 Factors Causing Decrease of Apparent Permeability in the Fracture

The most familiar factor that decreases the apparent permeability of the proppant pack, and therefore fracture conductivity, is *proppant-pack damage*. The reduction of permeability because of the presence of residue from the gelled fluid and failure of proppant because of closure stress are well understood. Since those phenomena exist in any fracture, they cannot be the general cause of the discrepancy in high-permeability fracturing. *Non-Darcy flow in the fracture* is also reasonably well understood. Separation of rate-independent skin from the variable-rate component by multiple-rate well testing is a standard practice. The effect of *phase change in the fracture* is less straightforward to quantify.

5.9.3.2 Factors Decreasing the Apparent Width

Embedment of the proppant in a soft formation is now well documented in the literature (Lacy et al. 1997, 1998).

5.9.3.3 Fracture-Face Skin Effect

The two sources of this phenomenon are filter-cake residue and the polymer-invaded zone. Sometimes the long-term cleanup (decrease of the skin effect) of a stimulated well is considered as indirect proof of such damage. It is assumed that linear polymer fluids invade more deeply into the formation and therefore, cause more fracture-face damage, as discussed by Mathur et al. (1995).

5.9.3.4 Permeability Anisotropy

While the anisotropy of permeability has only a limited effect on pseudoradial flow, the early-time transient flow regime of a stimulated well is very sensitive to anisotropy. This fact is often neglected when the well is characterized with one single skin effect.

5.9.3.5 Concept of Skin

It has to be emphasized that the concept of negative skin as the only measure of the "quality" of a well might be a source of the discrepancy itself. There is, in fact, no clear theoretical base for obtaining negative skin from short-time well-test data distorted by wellbore storage if the well has been stimulated. The use of infinite-acting reservoir + wellbore storage + skin type-curves in this case is not based on sound physical principles and might cause unrealistic conclusions.

In addition, the validity of the pseudoskin concept during the transient production period is an important issue. In general, the pseudoskin concept is valid only at late times. Thus, a fracture designed for optimal late-time performance may be not optimal at shorter times. One may ask how much performance is lost in selecting fracture dimensions that are optimal for a late time. This question has not been investigated, but it is reasonable to assume that the loss in performance is negligible for high-permeability reservoirs where the dimensionless times corresponding to a month or year are much higher than for low-permeability reservoirs.

Non-Darcy flow is another important issue that deserves specific consideration in the context of frac-and-pack. Non-Darcy flow in gas reservoirs causes a reduction of the productivity index by at least two mechanisms. First, the apparent permeability of the formation may be reduced (Wattenbarger and Ramey 1969) and second, the non-Darcy flow may decrease the conductivity of the fracture (Guppy et al. 1982).

5.10 Emerging Frac-and-Pack Technologies

5.10.1 Screenless and Rigless Frac-and-Pack Completions

On the basis of a recent industry survey, Tiner et al. (1996) report that the most common frac-and-pack technology advance being sought by producing companies is one that will allow removal or simplification of gravel-pack screens and tools, which are still used in most frac-and-pack completions. The most likely alternative is to eliminate the screen completely and use conventional fracturing methods, with a “twist”: the final proppant stage should be tailed-in with resin-coated sand to control proppant flowback. A number of these screenless frac-and-pack treatments have been completed, apparently with considerable success (Kirby et al. 1995).

Screenless frac-and-packs have the potential of dramatically reducing treatment costs and simplifying treatment execution; however, some questions remain: Can the resin-coated proppant in fact be placed as needed to prevent proppant flowback and ensure a high-conductivity connection between the fracture and the wellbore? What about formation sand production from those perforations that are not connected to the fracture? If successful, screenless frac-and-packs would also allow the development of multiple-zone frac-and-pack completions and through-tubing frac-and-pack recompletions. The major benefit of through-tubing completions, of course, is that they can often be done without a rig on location.

New frac-and-pack operations and equipment are also emerging to allow rigless coiled tubing completions in wells that are completed with gravel-pack screens (Ebinger 1996). Depending on the particular configuration, the treatment is pumped through a fracturing port/sleeve located below the production packer and above the screen. The port is opened and closed with a shifting tool on the coiled tubing. Because a gravel pack cannot be circulated into place, prepacked screens are required. This requirement seems to be the largest drawback to the technique. While the rigless frac-and-packs may be uniquely suited to dual-zone completions, the primary influence behind this trend is cost reduction by eliminating rig costs and inefficiencies associated with rig timing.

5.10.2 Complex Well-Fracture Configurations

Vertical wells are not the only candidates for hydraulic fracturing. Horizontal wells using frac-and-pack with the well drilled in the expected fracture azimuth (thereby ensuring a longitudinal fracture) appear to be (at least conceptually) a very promising prospect. However, a horizontal well intended for a longitudinal fracture configuration would have to be drilled along the maximum horizontal stress. This requirement, in addition to well-understood drilling problems, may contribute to long-term stability problems.

A rather sophisticated conceptual configuration would involve the combination of frac-and-pack with multiple-fractured vertical branches emanating from a horizontal parent well drilled above the producing formation. Of course, horizontal wells, being normal to the vertical stress, are generally more prone to wellbore stability problems. Such a configuration would allow for placement of the horizontal borehole in a competent, nonproducing interval. Besides, there are advantages to fracture-treating a vertical section over a highly deviated or horizontal section: (1) multiple starter fractures, fracture turning, and tortuosity problems are avoided, (2) convergence-flow skins ("choke" effects) are much less of a concern, and (3) the perforating strategy is simplified.

Nomenclature

A_L	Leakoff area, m^2
A_o	Fracture area at TSO, m^2
APC	Average areal proppant concentration, kg/m^2
B	Formation volume factor, m^3/m^3
C_{fD}	Dimensionless fracture conductivity
C_L	Fluid loss coefficient, m/s$^{1/2}$
c	Proppant concentration, kg/m^3
c_l	Proppant concentration in liquid, kg/m^3
c_m	Average proppant concentration loading, kg/m^3
c_s	Proppant concentration in slurry, kg/m^3
c_t	Total compressibility, Pa^{-1}
d_p	Perforation tunnel diameter, m
h	Reservoir net thickness, m
J	Productivity index, m^3/(s $\times$ Pa)
k	Reservoir permeability, m^2
k_{ck}	Choked or damaged fracture permeability, m^2
k_f	Fracture permeability, m^2
k_{fl}	Permeability of damaged region, m^2
k_p	Perforation tunnel permeability, m^2
L_p	Perforation tunnel length, m
M_{fip}	Total proppant mass, kg
M_{tso}	Total proppant mass at TSO, kg
N	Number of perforations
n	Number of moles
n_p	Number of perforations per unit length, m^{-1}
p	Reservoir pressure, Pa
p_D	Dimensionless pressure
p_e	Reservoir pressure at outer boundary, Pa
p_i	Initial reservoir pressure, Pa
p_{sc}	Standard conditions pressure, Pa

p_{wf}	Bottomhole flowing pressure, Pa
q	Flow rate, m^3/s
q_i	Pump rate, m^3/s
q_l	Fluid leakoff rate, m^3/s
R	Universal gas constant, J/(K × mol)
r	Radius, m
r_e	Reservoir radius, m
r_D	Dimensionless radius
r_s	Near wellbore damage radius, m
r_w	Wellbore radius, m
r_w'	Effective wellbore radius, m
r_{wD}'	Dimensionless effective wellbore radius
S_L	Spurt-loss coefficient, m
s	Skin factor
s_f	Fracture skin factor
s_{pf}	Perforation flow skin factor
s_{ck}	Choked fracture skin factor
s_{fl}	Fluid leakoff skin factor
s_{pp}	Partial penetration skin factor
s_o	Other possible skin factors
T	Absolute temperature, K
T_{sc}	Standard conditions temperature, K
t_D	Dimensionless time
t_i	Pumping time, s
t_o	Total time to TSO, s
V	Volume, m^3
V_{ci}	Clean fluid volume, m^3
V_F	Total (two-wing) fluid volume, m^3
V_f	Total fracture volume, m^3
V_i	Slurry volume, m^3
V_L	Leakoff volume, m^3
w_{ck}	Choked or damaged fracture width, m
w_f	Fracture width, m
x_{ck}	Choked or damaged fracture half-length, m
x_f	Propped fracture half-length, m
y_{fl}	Depth of damaged region, m
Z	Real gas deviation factor
Δp	Pressure gradient, Pa
Δp_{pf}	Perforation pressure drop, Pa
$\Delta p(t_o)$	Net pressure at TSO, Pa
μ	Fluid viscosity, Pa·s
ρ_p	Proppant particle density, kg/m^3
ρ_p'	Proppant bulk density, kg/m^3
ϕ	Reservoir porosity, fraction

References

Aggour TM, Economides MJ (1996) Impact of fluid selection on high-permeability fracturing. In: Paper SPE 36902. SPE European petroleum conference, Milan, 22–24 Oct 1996

Al-Hussainy R, Ramey HJ Jr, Crawford PB (1966) The flow of real gases through porous media. J Pet Technol, Volume 18, Number 5 (May 1966), 624–636

Balen RM, Meng H-Z, Economides MJ (1988) Application of the net present value (NPV) in the optimization of hydraulic fractures. In: Paper SPE 18541. SPE Easter regional meeting, Charleston, 1–4 Nov 1988

Barree RD, Rogers BA, Chu WC (1996) Use of frac-pack pressure data to determine breakdown conditions and reservoir properties. In: Paper SPE 36423. 71st annual technical conference and exhibition (ATCE) of SPE, Denver, 6–10 Oct 1996

Brown JE, King LR, Nelson EB, Ali SA (1996) Use of a viscoelastic carrier fluid in frac-pack applications. In: Paper SPE 31114. SPE formation damage symposium, Lafayette, 14–15 Feb 1996

Chapman BJ, Vitthal S, Hill LM (1996) Prefracturing pump-in testing for high-permeability formations. In: Paper SPE 31150. International symposium on formation damage control, Lafayette, 14–15 Feb 1996

Chudnovsky A, Fan J, Shulkin Y, Dudley JW, Shlyapobersky J, Schraufnagel R (1996) A new hydraulic fracture tip mechanism in a statistically homogeneous medium. In: Paper SPE 36442. SPE annual technical conference and exhibition, Denver, 6–9 Oct 1996

Cinco-Ley H, Samaniego-V F (1981a) Transient pressure analysis for fractured wells. J Pet Technol, Volume 33, Number 9 (September 1981), 1749–1766

Cinco-Ley H, Samaniego-V F (1981b) Transient pressure analysis: finite conductivity fracture case versus damaged fracture case. In: Paper SPE 10179. 56th annual fall technical conference and exhibition, San Antonio, 4–7 Oct 1981

Cinco-Ley H, Samaniego-V F, Dominguez-A N (1978) Transient pressure behavior for a well with a finite-conductivity vertical fracture. SPEJ, Volume 18, Number 4 (August 1978), 253–264

Dusterhoft R, Vitthal S, McMechan D, Walters H (1995) Improved minifrac analysis technique in high-permeability formations. In: Paper SPE 30103. SPE European damage symposium, The Hague, 15–16 May 1995

Earlougher RC Jr (1977) Advances in well test analysis, Monograph Series. SPE, Richardson

Ebinger CD (1996) New frac-pack procedures reduce completion costs. World Oil (April 1996), 71&75

Economides MJ, Watters LT, Dunn-Norman S (1998) Petroleum well construction. Wiley, Chichester

Fan Y, Economides MJ (1995a) Fracture dimensions in frac&pack stimulation. In: Paper SPE 30469. SPE annual technical conference & exhibition, Dallas, 22–25 Oct 1995

Fan Y, Economides MJ (1995b) Fracturing fluid leakoff and net pressure behavior in frac&pack stimulation. In: Paper SPE 29988. International meeting on petroleum engineering, Beijing, 14–17 Nov 1995

Gringarten AC, Ramey HJ Jr (1974) Unsteady-state pressure distributions created by a well with a single infinite-conductivity vertical fracture. SPEJ, Volume 14, Number 4 (August 1974), 347–360

Guppy KH, Cinco-Ley H, Ramey Jr HJ, Samaniego-V F (1982) Non-Darcy flow in wells with finite-conductivity vertical fractures. SPEJ, Volume 22, Number 5 (October 1982), 681–698

Hainey BV, Troncoso JC (1992) Frac-pack: an innovative stimulation and sand control technique. In: Paper SPE 23777. SPE international symposium on formation damage control, Lafayette, 26–27 Feb 1992

Hannah RR, Park EI, Porter DA, Black JW (1994) Combination fracturing/gravel-packing completion technique on the Amberjack, Mississippi Canyon 109 Field. SPE Prod & Facil, Volume 9, Number 4 (November 1994), 262–266

Horner DR (1951) Pressure build-up in wells. In: Third world petroleum congress, The Hague, Sec. II, pp 503–523

Howard GC, Fast CR (1970) Hydraulic fracturing. Monograph, vol 2, Henry L. Doherty Series. Society of Petroleum Engineers of AIME, New York/Dallas

Hunt JL, Chen C-C, Soliman MY (1994) Performance of hydraulic fractures in high permeability formations. In: Paper SPE 28530. 69th annual technical conference and exhibition, New Orleans, 25–28 Sept 1994

Kirby RL, Clement CC, Asbill SW, Ely JW (1995) Screenless frac pack completions utilizing resin coated sand in the gulf of Mexico. In: Paper SPE 30467. SPE annual technical conference and exhibition, Dallas, 22–25 Oct 1995

Lacy LL, Rickards AR, Ali SA (1997) Embedment and fracture conductivity in soft formations associated with HEC, borate and water-based fracture designs. In: Paper SPE 38590. SPE annual technical conference and exhibition, San Antonio, 5–8 Oct 1997

Lacy LL, Rickards AR, Bilden DM (1998) Fracture width and embedment testing in soft reservoir sandstone. SPE Drill & Complet, Volume 13, Number 1 (March 1998), 25–29

Mathur AK, Ning X, Marcinew RB, Ehlig-Economides CA, Economides MJ (1995) Hydraulic fracture stimulation of highly permeable formations: the effect of critical fracture parameters on oilwell production and pressure. In: Paper SPE 30652. SPE annual technical conference and exhibition, Dallas, 22–25 Oct 1995

Matthews CS, Russell DG (1967) Pressure buildup and flow tests in wells. Monograph, vol 1, Henry L. Doherty Series. Society of Petroleum Engineers of AIME, New York/Dallas

Mayerhofer MJ, Economides MJ, Nolte KG (1991) An experimental and fundamental interpretation of fracturing filter-cake fluid loss. In: Paper SPE 22873. 66th annual technical conference and exhibition of SPE, Dallas, 6–9 Oct 1991

Mayerhofer MJ, Ehlig-Economides CA, Economides MJ (1995) Pressure transient analysis of fracture-calibration tests. J Pet Technol, Volume 47, Number 3 (March 1995), 229–234

McGowen JM, Vitthal S (1996) Fracturing-fluid leakoff under dynamic conditions. Part 1: development of a realistic laboratory testing procedure. In: Paper SPE 36492. SPE annual technical conference and exhibition, Denver, 6–9 Oct 1996

McGowen JM, Vitihal S, Parker MA, Rahimi A, Martch WE Jr (1993) Fluid selection for fracturing high-permeability formations. In: Paper SPE 26559. SPE annual technical conference and exhibition, Houston, 3–6 Oct 1993

McGuire WJ, Sikora VJ (1960) The effect of vertical fractures on well productivity. J Pet Technol, Volume 12, Number 10 (October 1960), 72–74

McLarty JM, DeBonis V (1995) Gulf coast section SPE production operations study group - technical highlights from a series of frac-pack treatment symposiums. In: Paper SPE 30471. SPE annual technical conference and exhibition, Dallas, 22–25 Oct 1995

Meese CA, Mullen ME, Barree RD (1994) Offshore hydraulic fracturing technique. J Pet Technol, Volume 46, Number 3 (March 1994), Technology Today Series, 226–229

Meyer User's Guide (2010) Meyer fracturing simulators. Meyer & Associates, Natrona Heights

Mullen ME, Stewart BR, Norman WD (1994) Evaluation of bottomhole pressures in 40 soft rock frac-pack completions in the Gulf of Mexico. In: Paper SPE 28532. Annual technical conference and exhibition, New Orleans, 25–28 Sept 1994

Nolte KG (1979) Determination of fracture parameters from fracturing pressure decline. In: Paper SPE 8341. 54th annual fall technical conference and exhibition, Las Vegas, 23–26 Sept 1979

Nolte KG (1986) Determination of proppant and fluid schedules from fracturing pressure decline. SPE Prod Eng, Volume 1, Number 4 (July 1986), 255–265

Prats M (1961) Effect of vertical fractures on reservoir behavior – incompressible fluid case. SPE J (June 1961), 105–118

Prats M, Hazebroek P, Strickler WR (1962) Effect of vertical fractures on reservoir behavior – compressible fluid case. SPEJ, Volume 2, Number 2 (June 1962), 87–94

Raghavan R (1976) Well test analysis: well producing by solution-gas drive. SPEJ, Volume 16, Number 4 (August 1976), 196–208; Transactions of AIME, 261

Roodhart LP (1985) Fracturing fluids: fluid-loss measurements under dynamic conditions. SPEJ, Volume 25, Number 5 (October 1985), 629–636

Roodhart LP, Kuiper TOH, Davies DR (1988) Proppant-pack and formation impairment during gas-well hydraulic fracturing. SPE Prod Eng, Volume 3, Number 4 (November 1988), 438–444

Roodhart LP, Fokker PA, Davies DR, Shlyapobersky J, Wong GK (1994) Frac-and-pack stimulation: application, design, and field experience. J Pet Technol, Volume 46, Number 3 (March 1994), 230–238

Saucier RJ (1974) Considerations in gravel pack design. J Pet Technol, Volume 26, Number 2 (February 1974), 205–212

Shlyapobersky J, Wong GK, Walhaugh WW (1988) Overpressure calibrated design of hydraulic fracture simulations. In: Paper SPE 18194. SPE annual technical conference and exhibition, Houston, 2–5 Oct 1988

Singh P, Agarwal RG (1990) Two-step rate test: new procedure for determining formation parting pressure. J Pet Technol, Volume 42, Number 1 (January 1990), 84–90

Smith MB, Miler II WK, Haga J (1987) Tip screenout fracturing: a technique for soft, unstable formations. SPE Prod Eng, Volume 2, Number 2 (May 1987), 95–103

Stewart BR, Mullen ME, Ellis RC (1995) Economic justification for fracturing moderate to high permeability formations in sand control environments. In: Paper SPE 30470. SPE annual technical conference and exhibition, Dallas, 22–25 Oct 1995

Tiner RL, Ely JW, Schraufnagel R (1996) Frac packs – state of the art. In: Paper SPE 36456. 71st annual technical conference and exhibition (ATCE) of SPE, Denver

Valko P, Oligney RE, Schraufnagel RA (1996) Slopes analysis of frac & pack bottomhole treating pressures. In: Paper SPE 31116. SPE formation damage control symposium, Lafayette, 14–15 Feb 1996

van Everdingen AF (1953) The skin effect and its influence on the productive capacity of a well. Pet Trans, AIME, Volume 198:171–176

van Everdingen AF, Hurst W (1949) The application of the Laplace transformation to flow problems in reservoirs. Pet Trans, AIME, Volume 186:305–324

van Poolen HK, Tinsley JM, Saunders CD (1958) Hydraulic fracturing – fracture flow capacity vs well productivity. Pet Trans, AIME, Volume 213:91–95

Vitthal S, McGowen JM (1996) Fracturing fluid leakoff under dynamic conditions part 2: effect of shear rate, permeability and pressure. In: Paper SPE 36493. SPE annual technical conference and exhibition, Denver, 6–9 Oct 1996

Wattenbarger RA, Ramey HJ Jr (1969) Well test interpretation of vertically fractured gas well. J Pet Technol, Volume 21, Number 5 (May 1969), 625–632

Wong GK, Fors RR, Casassa JS, Hite RH, Shlyapobersky J (1993) Design, execution and evaluation of frac and pack (F&P) treatments in unconsolidated sand formations in the Gulf of Mexico. In: Paper SPE 26563. 68th annual technical conference and exhibition of SPE, Houston, 3–6 Oct 1993

Chapter 6
Treating Fluid Selection

Contents

Abstract The major types of treating fluids that are in use in sand control are conventional linear gels, borate-crosslinked fluids, organometallic-crosslinked fluids, and aluminum phosphate-ester oil gels. The general behavior of these fluid systems is described. Fluid loss properties, breaking systems, and resulting formation damage are discussed and recommendations for treating fluid selection in sand control are offered.

6.1 Introduction

The proper selection of treating fluid is one of the most critical elements in gravel-pack and frac-and-pack completion designs. To select the proper fluid, concerns such as fluid-loss control, fracture conductivity, formation damage, and proppant transport must be considered.

D. Matanović et al., *Sand Control in Well Construction and Operation*,
Springer Environmental Science and Engineering,
DOI 10.1007/978-3-642-25614-1_6,

Extensive testing has been conducted to promote better understanding of fracturing fluid behavior in treatments of high-permeability formations. In these tests, the fluids were evaluated for fluid-loss properties, regained permeability (formation damage), and fracture conductivity. The results from these tests have proven very helpful in making the best fluid selection for a given well.

In this chapter, types of fluid systems, additives, and the general behavior of these fluid systems is discussed.

6.2 Available Fluid Systems

As many as 50 different fluids have been developed to solve various needs within the oil- and gas-well stimulation and completion markets. The major types of fluids that remain at the backbone of the industry are as follows (Dusterhoft 1994):

- Conventional linear gels,
- Borate-crosslinked fluids,
- Organometallic-crosslinked fluids,
- Aluminum phosphate-ester oil gels.

All of these fluids may be run as two-phase systems, since they are all compatible with nitrogen. However, only the linear gels and some of the organometallic-crosslinked fluids are compatible with carbon dioxide. A brief description of each of the fluid systems listed above and how they can be applied in high-permeability fracturing treatments is included in the following sections.

6.2.1 Conventional Linear Gels

Conventional linear gels are very simple to use and can be formulated with a wide array of different polymers and fluids. Common polymer sources used with the linear gels are guar gum, hydroxypropyl guar (HPG), hydroxyethyl cellulose (HEC), carboxymethylhydroxypropyl guar (CMHPG), and carboxymethylhydroxyethyl cellulose (CMHEC).

Previous studies performed with these fluids have indicated that gel residue from guar fluids can be as high as 8–10% by weight. The high residue content of guar gels can cause permeability reduction in the proppant pack of the fracture, if further cleanup measures are not applied (Cooke 1975; Almond and Bland 1984).

Similar problems have been observed with linear HPG and CMHPG, though the resultant damage is not as extreme with this type of fluid system. In both HPG and CMHPG fluids, the residue content can be from 1% to 3% by weight. HEC fluid systems are virtually residue free and provide the best proppant-pack permeability.

The general characteristics of linear gels are poor proppant transport and low fluid viscosity. In lower-permeability formations (less than $0.1 \times 10^{-3}\ \mu m^2$), linear gels control fluid loss very well, whereas in higher-permeability formations fluid loss can be excessive. Linear gels tend to form thick filter cakes on the face of lower-permeability formations, which can adversely affect fracture conductivity. The performance of linear gels in higher-permeability formations is just the opposite, since it forms no filter cake on the formation wall. Much higher volumes of fluid are lost due to viscous invasion of the gel into the formation. Fracture conductivity can be much higher when linear gels such as HEC are used.

New biopolymer gel systems have been recently added to the selection of gravel-pack fluids. These biopolymer systems offer interesting properties for frac-and-pack applications also. These fluids feature clean, controllable breaks that result in excellent regained permeability and fracture conductivity. The new biopolymer systems that have been tested to date have had restricted use in frac-and-pack treatments because of their high cost and unfavorable shear-thinning properties (McGowen et al. 1993).

6.2.2 Borate-Crosslinked Fluids

Borate-crosslinked fluids were once restricted from high-temperature applications, but advances has improved them for use in temperatures to 150°C (Harris 1993; Ely 1989; Gulbis and Hodge 2000). The polymers most often used in these fluids are guar and HPG. The crosslink obtained by using borate is reversible and is triggered by altering the pH of the fluid system. The reversible characteristic of the crosslink in borate fluids helps them clean up more effectively, resulting in good regained permeability and conductivity. In addition to good cleanup properties, with the proper composition, borate fluids provide good proppant transport, stable fluid rheology, and low fluid loss. The use of borate-crosslinked fluids has increased significantly over the last decade, and HPG-borates show great potential for high-permeability applications.

6.2.3 Organometallic-Crosslinked Fluids

Organometallic-crosslinked fluids have long been the most popular class of fracturing fluids. Primary fluids that are widely used are titanate and zirconate complexes of guar, HPG, CMHPG, or CMHEC. These fluids are extremely stable at high temperatures and are currently the only type of fluids that can be used at bottomhole temperatures that exceed 150°C.

The proppant transport capabilities of organometallic-crosslinked fluids are excellent, and these fluids form a very resilient filter cake on the face of the fracture. The metallic bonds which form the crosslink mechanism in these fluids are not reversible and do not break when exposed to conventional gel-breaking systems. Because of the strong bonds of these fluids, the filter cakes deposited on the fracture face can be more difficult to clean up and can result in impaired fracture conductivity. Cleanup difficulty is the major disadvantage to these types of fracturing fluids; thus, their use in high-permeability formations is a questionable practice. When carbon dioxide is used or when dealing with high reservoir temperatures, organometallic-crosslinked fluids may be necessary despite cleanup difficulties.

6.2.4 Aluminum Phosphate-Ester Oil Gels

Gelled oil systems were the first high-viscosity fluids used in hydraulic fracturing operations. A major advantage to this type of fluid is its compatibility with almost any formation type. There are some disadvantages in using gelled oils. Gelling problems can occur when using crude oils and the cost of using refined oils is very high. Also there are greater concerns regarding personnel safety and environmental impact, as compared to most water-fluids. In wells with high-permeability formations, the advantages of using gelled oils can outweigh their disadvantages, if safety and environmental issues can be resolved.

6.2.5 Foamed and Other Fluids

Other fluids such as polymer-emulsion systems and gas-energized systems exist, but they have limited application in high-permeability formations due to environmental, safety, or equipment limitations. Foamed or energized fluids may be especially useful for frac-and-pack treatments of high-permeability formations in low-pressure gas reservoirs.

6.3 Breakers

For high-permeability fracturing applications, use of the proper gel breaker system is crucial to realizing maximum regained permeability and fracture conductivity. In low-permeability applications, the use of delayed, encapsulated breakers has proven very effective in breaking the filter cake on the formation face and maximizing fracture conductivity. High-permeability applications, however, result in the invasion of a viscous gel into the formation and pose the additional concerns which follow:

- Encapsulated breakers "plate out" on the fracture face or stay in the proppant bed, which helps break the filter cake and gel in the proppant pack. This type of breaker does not help break the gel that enters the formation.

- The damage caused by viscous invasion of the gel can be serious if the gel remains unbroken in the formation. A reduction in regained permeability is the first potential source of formation damage, since the unbroken gel blocks the pore spaces in the formation. A second potential source of damage can be caused by the flow of unbroken gel from the formation into the proppant pack, which can reduce fracture conductivity.
- Cleanup time can be drastically increased, sometimes requiring several days or weeks to recover the load fluid from the fracturing treatment. Producing the well at higher drawdown pressure is sometimes attempted to speed up the load-fluid recovery. These higher drawdown pressures can apply additional stress to the formation and result in early sand production, which negates the effect of the fracturing treatment.

High-permeability treatments require the use of breakers which are in solution with the gel systems, so that even the gel which leaks off into the formation is completely broken at the proper time. It is still recommended that additional encapsulated breaker be mixed into the proppant-bearing stages of the treatment. This helps ensure that an adequate amount of breaker is present to break the filter cake on the fracture face and thus maximizes fracture conductivity.

Break testing should be performed before the job is pumped. These tests help ensure that break times are sufficient to place the treatment, but short enough to allow the well to be put on production and cleaned up in a reasonable amount of time. The breaker schedule should provide good fluid properties for twice the anticipated pump time and a complete break in 2–4 h.

A new procedure in which a dual fluid system is pumped has tested (Dusterhoft 1994). In this procedure, a high-efficiency pad volume is pumped, followed by a low-efficiency proppant placement fluid. This dual-stage approach is designed to more effectively place proppant into the created fracture, particularly in very high-permeability formations where it may not be possible to create adequate geometry with a linear gel. Test results have indicated that the fluid used to place the proppant can be chosen so that it will effectively break the filter cake of the pad fluid and greatly increase the fluid leakoff rate. Proper fluid selection makes it possible to control the amount of fluid loss while pumping the pad volume, thus allowing the desired fracture length and width to be created using smaller pad volumes. For example, using a borate-crosslinked fluid system improves the fluid-loss control and increases the fluid efficiency of the pad volume. Following the borate system with a pH-buffered HEC for proppant placement will help reverse the filter cake formed by the borate fluid and break the crosslink of the borate gel that leaked off into the formation. There are several benefits to this approach. Overall, less fluid is required to be pumped, minimizing potential formation damage. The linear HEC gel within the proppant bed provides maximum fracture conductivity. This dual-fluid technique, if applied with a well-designed breaker schedule, can result in reduced formation damage and maximum fracture conductivity. This technique allows the use of HEC as well as other gelling agents for the linear gel stage. The same benefits can be obtained by using the borate-crosslinker and buffering the base gel.

6.4 Fluid Loss

Dynamic fluid-loss studies performed on high-permeability cores have provided very useful information about fluid-loss properties as a function of gel type and formation properties (McGowen and McDaniel 1988; McGowen et al. 1993; Parker et al. 1994). These test results have indicated that in high-permeability rock, selection of a proper treatment fluid is the most effective means of controlling fluid loss. In most cases, the uses of a particulate-type fluid loss additive can improve the fluid loss to the formation; however, these types of additives can damage fracture conductivity during production (Fig. 6.1).

Fluid-loss testing has shown that crosslinked fluids are far superior to linear gel systems for reducing fluid loss in high-permeability formations. Comparison of fluid loss using crosslinked gels shows that the borate-crosslinked fluids are particularly more efficient than any of the organometallic systems tested. The high fluid-loss efficiency of the borate fluids, plus the advantages of their reversible crosslink and their easy cleanup has made them the preferred choice for crosslinked gels. Based on these test results and on field results, borate-crosslinked fluids are highly recommended in high-permeability wells where HEC performs poorly.

Viscous fluid invasion predominantly controls fluid loss in high-permeability formations, more so than in conventional fracturing in low-permeability formations. As a result of this fluid-loss behavior, the performance of linear gels and crosslinked gels is very different and is discussed in detail in the following sections.

6.4.1 Linear HEC Fluids

In formations with permeability that exceeds 20×10^{-3} μm^2, the fluid-loss behavior of linear HEC gel systems is completely governed by the invasion of the whole

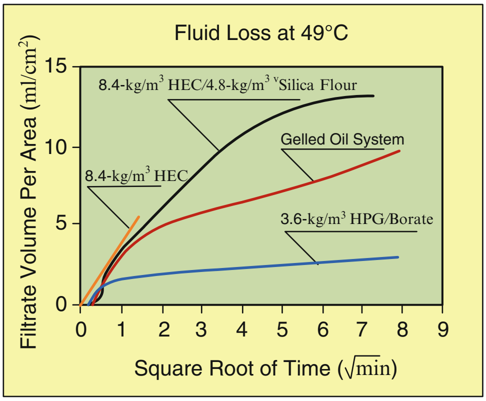
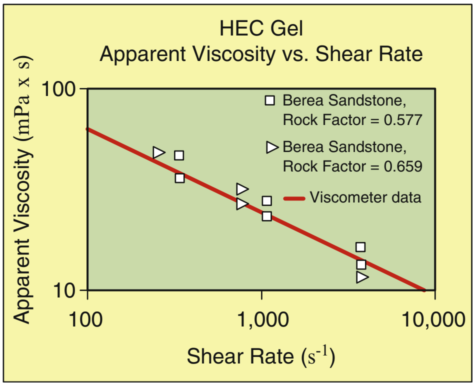


Fig. 6.1 The filtrate volume data from fluid-loss tests run on Berea sandstone cores at 49°C (McGowen et al. 1993)

Fig. 6.2 Apparent viscosity versus shear rate for two tests using HEC fluid at 82°C inside Berea sandstone core (McGowen et al. 1993)



gel into the formation. A filter cake does not build up on the faces of the fracture, and the leakoff rate is controlled by the rheological behavior of the gel in the porous medium. HEC gels have been observed to behave as power law fluids in high-permeability formations. A plot of the measured apparent viscosity versus shear rate in a test core for an HEC fluid system is shown in Fig. 6.2. The non-Newtonian power law nature of fluid leakoff in high-permeability formations has led to some interesting insights into its fluid leakoff behavior. One consequence of using non-Newtonian fluids is that their leakoff can decrease faster over time than that of a Newtonian fluid.

As a non-Newtonian fluid invades the formation rock, the shear rate inside the porous media is very high, typically about 10,000 s^{-1}. As the depth of fluid invasion increases, the filtrate rate decreases, as does the shear rate within the rock. The fluid's apparent viscosity increases with the decreasing shear rate, due to the fluid's shear thinning nature. The increase in apparent viscosity aids in controlling fluid leakoff. This fluid behavior also implies that high-permeability treatments with linear gels should have higher fluid efficiencies than predicted with a single value of fluid loss coefficient and that using fluids that are highly non-Newtonian in nature (lower values of n') may provide lower fluid efficiency.

6.4.2 Guar-Based Linear Gels

Some guar-base gels such as HPG show the same non-wall-building characteristics as HEC fluids in high permeability. However, guar gel tends to build a filter cake and most tend to develop a better filter cake than the HEC fluids. This wall-building tendency has a complex leakoff function which is initially governed by viscous invasion of a non-Newtonian fluid, then changes over time to a system dominated by filter cake. This tendency to develop a filter cake with guar fluids is believed to be due to the high residue content of this fluid as compared to HEC. The filter-cake buildup and the deeper formation damage makes guar unsuitable for frac-and-pack applications. HPG and CMHPG are usable frac-and-pack fluids, due to their lower gel-residue content. These fluids, however, do not perform as well as HEC.

6.4.3 Crosslinked Fluid Systems

Crosslinked fluid systems that were tested showed filter cake formation and followed the more classical square root of time models for fluid loss. A very important factor about this type of fracturing fluid system is that although the results of fluid-loss tests have followed the classical models of spurt loss followed by filter-cake formation, very high spurt volumes, and long spurt times are observed in high-permeability cores. All observations suggest that even with the high viscosity of crosslinked fluid systems, the early leakoff rate is primarily governed by viscous invasion of the gel into the formation. The depth of formation invasion and the amount of time required to build a filter cake appears to be a complex function of the formation permeability, fluid viscosity, and differential pressure. Crosslinked gels do not invade the formation as deeply as linear gels, but they do develop a very concentrated buildup in the formation near the fracture face, which can be very difficult to clean up.

Viscous invasion of the formation by crosslinked fluids has been observed to govern fluid loss until a filter cake formation occurs. Compared to linear gels, the higher viscosity crosslinked fluids consistently have shown lower fluid loss and shallower invasion of filtrate into the cores tested. Classical fluid-loss models can be used to model the leakoff of crosslinked fluids in high-permeability formations, but the early spurt volumes are very significant and should not be ignored when designing a fracturing treatment. Test data are shown in Figs. 6.3 and 6.4.

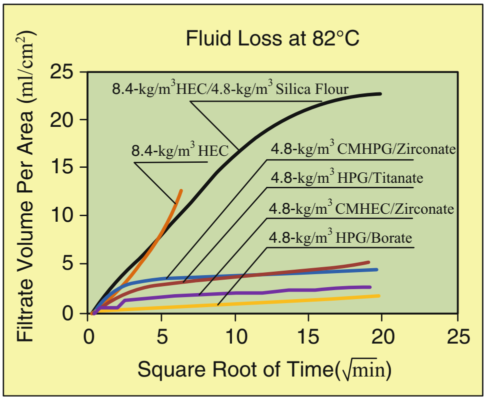
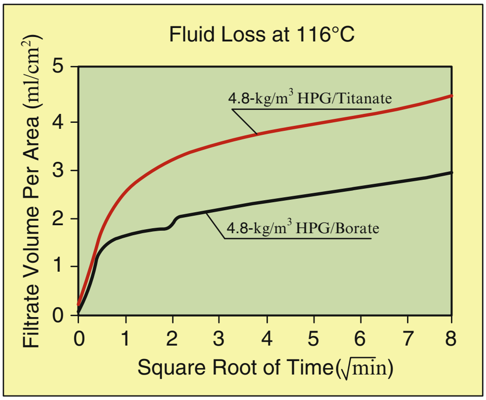


Fig. 6.3 The filtrate volume data from fluid-loss tests run on Berea sandstone cores at 82°C (McGowen et al. 1993)

Fig. 6.4 The filtrate volume data from fluid-loss tests run on Berea sandstone cores at 116°C (McGowen et al. 1993)



6.5 Formation Damage

The fluid-loss test results discussed previously indicate that fracturing fluids behave very differently in high-permeability formations than they do in low-permeability formations. The viscous invasion of the gels into the formation is a significant variation from behavior in conventional, low-permeability formations and has been investigated. A multiport Hassler sleeve was used as a laboratory tool to monitor the depth of invasion during static fluid loss tests. The flow was then reversed through the sleeve (and the core being tested) to evaluate the regained permeability at various regions of the core. These formation-damage tests (to determine regained permeability) were conducted at several different temperatures with selected fluids (McGowen et al. 1993).

Formation-damage test results were very consistent and show HEC and borate-crosslinked gels to cause the least amount of damage. Although core invasion was very deep with the HEC fluid, the very low residue content of this fluid allows it to flow back very efficiently. The linear guar-based gels show deep invasion and high residue content; the combination of these factors causes severe formation damage. Crosslinked gel systems, in general, show much less depth of invasion. Using the borate-crosslinked fluids, with their high viscosity, results in fewer invasions than use of organometallic fluid systems. Also, the borate fluids clean up much more easily than the organometallic fluids, and give overall better results in high-permeability formations.

Based on the results of the formation-damage studies, the following general observations and recommendations were made:

- Temperature limitations of HEC restrict its use to temperatures less than 80°C, while borate-crosslinked fluids remain effective up to 150°C.
- HEC shows low damage to high-permeability formations. Borate-crosslinked gels show less permeability recovery than do HEC fluids.

- Depth of invasion for HEC can be great due to poor fluid-loss control and some deeper damage can result. Invasion depths from using borate-crosslinked fluids in high-permeability formations are significant and can cause increased formation damage near the fracture face.
- The importance of an effective in-solution breaker system is readily evident when evaluating formation damage. Improved cleanup of gels can be obtained in almost all situations if a more complete breaking of the gel occurs within the formation matrix. The dual-fluids approach to fluid-loss control can help manage more efficient break and cleanup.
- In fracturing applications, a greater degree of formation damage can be tolerated than in gravel-pack applications. In most cases, production simulator results have indicated that good regained permeabilities (in excess of 15%) will provide excellent results. This observation favors the borate-crosslinked fluid systems in high-permeability formations since they provide better fluid-loss control combined with acceptable levels of formation damage.

6.6 Fracture Conductivity

Fracture conductivity testing was performed with the same selected fracturing fluids and core types, and at the same temperatures as the fluid-loss and formation-damage tests. HEC gels provided the best overall fracture conductivity. The results of this testing are somewhat conservative, since the same fluids and in-solution breaker systems from the fluid-loss tests and the formation-damage tests were used. No delayed or encapsulated breakers were mixed with the proppant. Had these breakers been used, the performance of the crosslinked gels would have been greatly increased, resulting in better fracture conductivity.

The fracture conductivity tests did show that under most conditions, the HEC and the borate-crosslinked gels outperformed all other fluids. When silica flour was used as a fluid loss additive, it caused significant reductions in fracture conductivity.

6.7 Gravel-Pack Completions

Gravel packing is slightly different from frac-and-pack completions since it does not involve tip-screenout fracturing. Gravel packing does, however, involve the near-wellbore region of the well and thus gravel-pack fluids must be kept very clean. All brines used in gravel-packing procedures should be filtered before being injected into the well. Gelled fluids should be sheared and filtered to remove any microgels that could damage the formation or the gravel-pack media.

Formation damage is a primary concern in gravel-pack completions. To prevent formation damage, HEC, biopolymers, or clean brines are the preferred fluids for most gravel-pack completions. If heavy brines are required for well control, special gelling considerations are required to ensure adequate viscosity and stability. Specialty products are available for such applications.

Sandstone acidizing procedures are sometimes used before, during, or after a gravel-pack treatment to help remove mobile fines and speed the cleanup of the load fluid. In some cases, formation conditions are not favorable for acidizing due to poor consolidation or incompatibilities with the fluids being pumped. Concerns about formation stability and compatibility should be addressed before completing the job.

6.8 Conclusions and Recommendations

The results from formation-damage tests and fracture-conductivity tests have shown HEC to be the most applicable linear gel for frac-and-pack treatments (Parker et al. 1994; McGowen et al. 1993). Borate-crosslinked HPG gels were found to be the most effective crosslinked fluid system for frac-and-pack completions. The use of either a linear gel or a crosslinked gel is very dependent on the formation permeability, reservoir fluid, and reservoir pressure of the candidate well.

Formation damage and fracture conductivity studies have shown that breakers should be in solution when fracturing high-permeability formations so that the entire crosslinked gel volume that leaks off into the formation can be effectively broken. Fracture conductivity can be enhanced if an encapsulated breaker is placed in the proppant pack.

Some unique well conditions may require the use of fluid systems that are different from the HEC linear gel and borate-crosslinked HPG gel prescribed previously as most applicable to all frac-and-pack procedures.

References

Almond SW, Bland WE (1984) The effects of break mechanism on gelling agent residue and flow impairment in 20/40 mesh sand. In: Paper SPE 12485. Formation damage control symposium, Bakersfield, 13–14 Feb 1984

Cooke CE Jr (1975) Effects of fracturing fluids on fracture conductivity. J Pet Technol, Volume 27, Number 10 (October 1975), 1273–1282

Dusterhoft RG (1994) FracPac completion services; stimulation and sand-control techniques for high-permeability oil and gas wells. Halliburton Energy Services, Houston

Ely JW (1989) Fracturing fluids and additives. In: Gidley JL, Holditch SA, Nierode DE, Veatch RW Jr (eds) Recent advances in hydraulic fracturing, vol 12, SPE Monograph. Society of Petroleum Engineers, Richardson

Gulbis J, Hodge RM (2000) Fracturing fluid chemistry and proppants. In: Economides MJ, Nolte KG (eds) Reservoir stimulation, 3rd edn. Wiley, Chichester

Harris PC (1993) Chemistry and rheology of borate-crosslinked fluids at temperatures to 300°F. J Pet Technol, Volume 45, Number 3 (March 1993), 264–269

McGowen JM, McDaniel BW (1988) The effects of fluid preconditioning and test cell design on the measurement of dynamic fluid loss data. In: Paper SPE 18212. SPE annual technical conference and exhibition, Houston, 2–5 Oct 1988

McGowen JM, Vitthal S, Parker MA, Rahimi A, Martch WE Jr (1993) Fluid selection for fracturing high-permeability formations. In: Paper SPE 26559. SPE annual technical conference and exhibition, Houston, 3–6 Oct 1993

Parker MA, Vitthal S, Rahimi A, McGowen JM, Martch WE (1994) Hydraulic fracturing of high-permeability formations to overcome damage. In: Paper SPE 27378. SPE international symposium on formation damage control, Lafayette, 7–10 Feb 1994

Chapter 7
Perforating for Sand Control

Contents

Abstract To assure the success of sand control job in cased and cemented wellbore it is essential to proper design and execute the perforating program. The definition of adequate number of perforations with sufficient depth of penetration (length) will allow production with desired production rate.

The stability of perforation is controlled by arches formed on the perforation channel. With control of the drawdown they can be stable all the time. So the critical drawdown or production rate (velocity) should be determined or measured.

Controlled distance between perforations combined with perforation throat diameter will prevent the sand to collapse.

The perforating process is an essential factor of the set-through method of well completion. That is probably the most important of all completion functions in cased holes. Adequate communication between the wellbore and all desired zones is essential to evaluate and to optimize production and recovery from each zone. Perforation procedure should accomplish the following objectives, not necessarily in the order of importance: (1) obtain a clean, undamaged, and productive perforation, (2) penetrate the production interval as far as possible, (3) shoot a smooth and round entrance hole in the casing, (4) minimize casing and cement damage and (5) obtain the maximum flow rate with the minimum number of perforations.

Openings in casing, cement sheath and formation can be done with: bullets, jet perforators (shaped-charge explosives), hydraulic (erosional) perforators, and hydraulic (mechanical) cutters. Today almost 90% of openings are the result of shaped charge usage. The possible use of specific equipment depends on formation strength and downhole temperature (limitation according explosives max. 260°C).

It is obvious (Fig. 7.1) that bullet guns are the best only in rocks with small compressive strength (unconsolidated sands) (Buzarde LE Jr et al. 1982). In all

D. Matanović et al., *Sand Control in Well Construction and Operation*,
Springer Environmental Science and Engineering,
DOI 10.1007/978-3-642-25614-1_7,

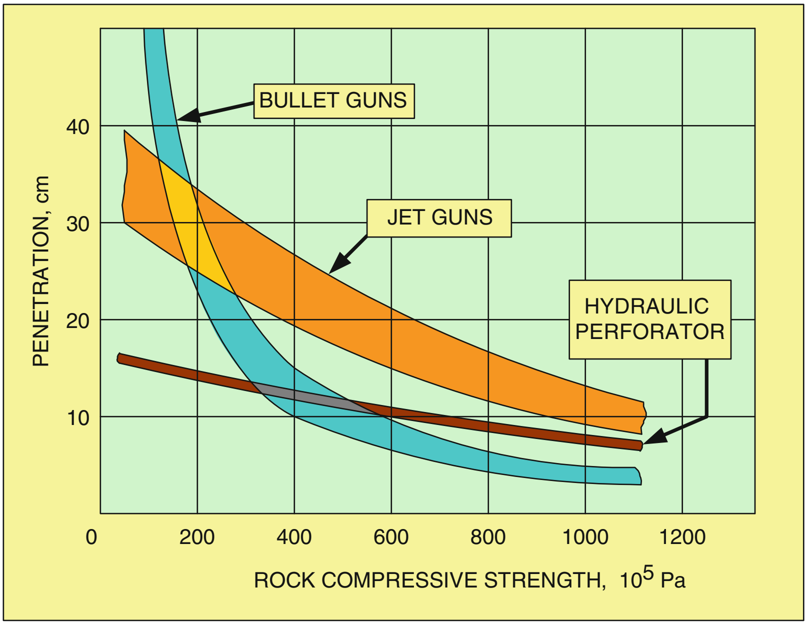


Fig. 7.1 Penetration depth with various types of perforators according to rock compressive strength (Buzarde LE Jr et al. 1982)

other cases jet perforators enable highest penetration depth. The problems associated with shaped charges debris that use to plug the perforations have been solved at the beginning by perforation washing or surging. Perforating in under-balanced conditions has lead to better results in most cases, but there is steel a need for thorough preparation for each project.

Recently so called dynamic-under-balanced system was introduced (Chang et al. 2005). The system comprises an atmospheric chamber that is activated after perforating in overbalanced conditions. That will produce a short and sharp under-balanced state across the perforations (Fig. 7.2). Because of that the fluid invasion through the way of smaller pressure will clean the debris from the perforations and crushed surrounding region (Jain et al. 2010).

Bullet perforating (Fig. 7.3 left) includes a multi barrel gun designed to be lowered into a well, positioned at the desired interval, and fired electrically from surface controls. They produce uniform and smooth entry holes, and will not cause casing damage. Also they leave no debris in the well. The perforating gun with bullets is positioned at the desired depth besides the formation to be perforated (Well Servicing and Workover 1971). The bullet is fired electrically. Due the explosion bullet is pushed through the casing. It continues through the second (if any or more) casing and cement sheath(s). Intention is to perforate deep enough to the formation to bridge the near well bore damaged zone. At last the perforation is done. The only thing that remains in perforation is the bullet. When used for sand

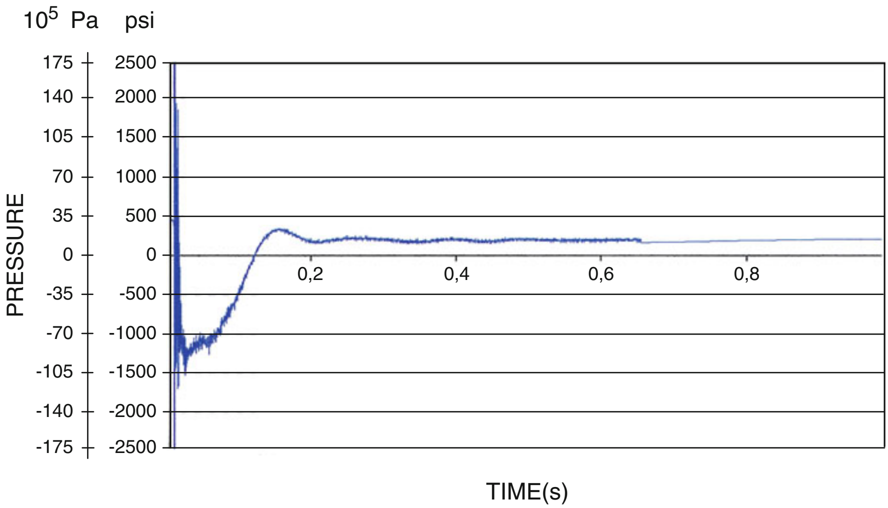


Fig. 7.2 Pressure change during dynamic-under-balanced perforating (Chang et al. 2005)

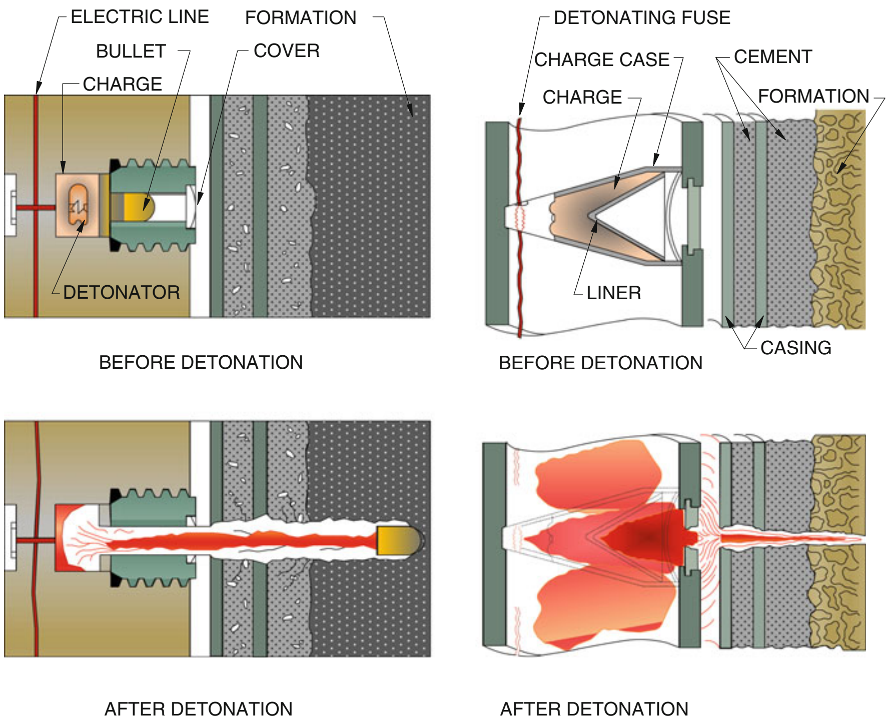


Fig. 7.3 Perforating process with bullet perforator (*left*) and shaped charge (jet) perforator (*right*) (Well Servicing and Workover 1971)

control (gravel packs), the bullets of 50.8 mm (2″) diameter are possible. They are the best in formations of small compressive strength (unconsolidated sands); perforation length up to 610 mm.

The shaped-charge explosives (Fig. 7.3 right) are used instead bullets. They are the overall best perforators; they give the greatest performance in formations from moderate to high compressive strength. With jet perforators there is a possibility of perforation plugging with debris, perforation is not smooth all along, the compacted zone is produced, and there is a possibility of casing damage or rupture. Shaped charge consists of: (1) conical liner, (2) initial charge, (3) main charge, and (4) charge case.

Detonation is ignitioned from the surface electrically or with mechanical bar, and transferred to the detonating fuse. That fires the buster. After 5 μs detonation wave begins to collapse cone as jet forms. After 10 μs jet perforates the casing and penetrates the cement. The final state is with jet penetrated far back into the formation. The problem is that shaped-charge debris can plug perforation openings in a formation, and perforation walls are also compacted due the pressure and temperature. Perforation opening can be from 8.4 to 19 mm. Perforation length can be from 203 to 1,220 mm.

7.1 Perforation Requirements

Field experience and conducted research programs (Bruist 1974) have showed that there is a need of pre-packing the perforations after they have been done. At that time the large diameter, high-density systems have been used. Washing or surging has been used to clean the perforations by removing plugging material or formation sand. As the optimum procedure, the perforation pre-packing was introduced. Perforation washing tests (Penberthy Jr. 1988) have shown that it should be conducted with maximum pump rate with water or brine as the wash fluid. The use of viscosified fluids resulted in filter cake production and reduction of formation sand removal. Also surging of long intervals can not assure that all perforations will be cleaned uniformly. Much more gravel pre-packing after surging may cause the gravel and formation sand to intermix.

Generally for geometrical perforating parameters affect the well's productivity (Bell 1984). These are: (1) effective shot density (Fig. 7.4), *SPM* (number of shots per unit length); (2) perforation tunnel length (Fig. 7.5), L_p (into formation); (3) gun phasing, Φ (angular displacement of successive perforations; and (4) diameter of perforation, d_p (within the formation). Depending of values of these parameters, a "skin," s_1 is created to either enhance or impair flow. Two additional environmental factors are: (1) wellbore damage, s_2 due to wellbore fluid invasion in the formation to a distance, r_s that can reduce permeability, k_s depending if perforation stops in or passes through this zone; and (2) compacted or crushed zone, k_c during jet perforating, s_3. The result will be "total skin," s.

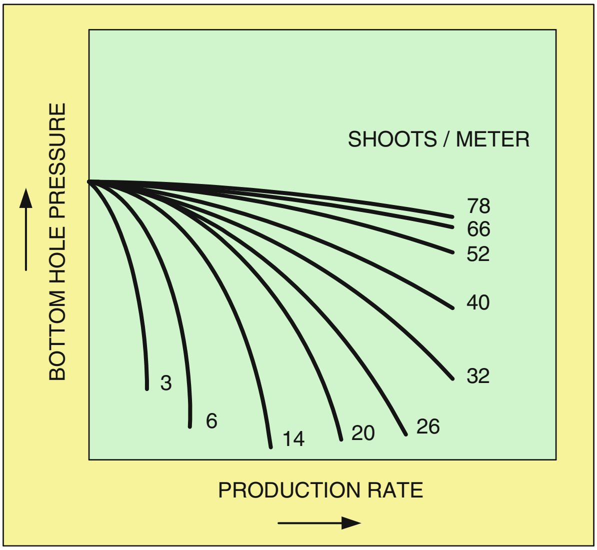


Fig. 7.4 Production rate according to the number of perforations per specified length (Cheng 1985)

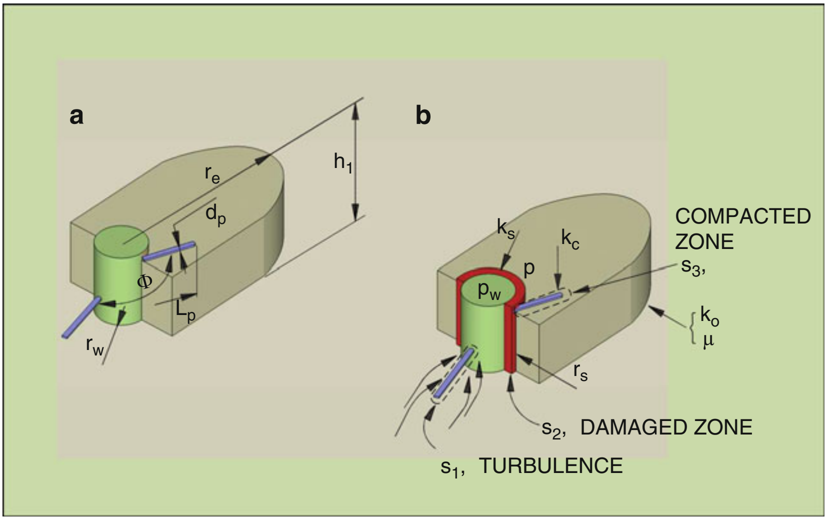


Fig. 7.5 Perforating parameters that affect the well productivity (Bell 1984): (**a**) geometrical parameters, (**b**) physical and environmental parameter

The perforation tunnel is in some cases filled with solids from kill fluid with reduced permeability, and surrounding zone can be partially plugged with fluids and solids. That can alter productivity. Thus the perforation surrounding area permeability must be calculated (Eq. 7.1) to enable determination of normalized perforation-permeability ratio (*NPPR*); a measure of how permeable is the perforation when compared to the original rock permeability. Where k_p is the permeability

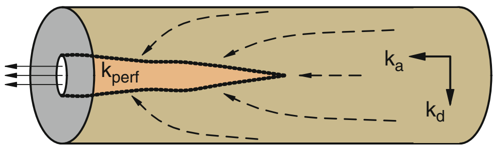


Fig. 7.6 Permeability of perforation surrounding area (Tronvoll et al. 2004)

of the perforation tunnel, k_a is the permeability of the core in the axial direction, and k_d is the permeability of the core in the diametrical direction (Fig. 7.6).

$$NPPR = \frac{k_p}{\sqrt{\frac{k_a^2 + k_d^2}{2}}} \tag{7.1}$$

The study conducted to investigate perforations in unconsolidated sands (Walton et al. 2001) has in fact showed that there will be no real cavity behind casing regardless the pressure conditions. Just the thin black streak was the indication of the path of the jet. The hemispherical dilated zone was also evident. The material in the dilated zone was in state of tensile failure. Through flow tests little sand was produced al low flow rates but catastrophic sand production happens after critical flow rate has been reached.

The sand production starts because of three main reasons: (1) drawdown changes or flow rate changes, (2) depletion of the reservoir that results with higher effective stress and production of higher water amount. When talking about perforations, sand must first be separated from the perforation tunnel walls and the flowing fluid must be capable to transport it. All of that is controlled by the stability of perforation tunnels over the producing life of the well (Venkitaraman et al. 2000). To achieve perforation stability it is recommended to use deep penetrating charges of small diameter, because the smaller holes are more stable than large ones. After determination of rock mechanical properties it is possible to determine how to space perforations in the wellbore. That means to identify shot density and phasing. The optimal approach is in spacing the perforations with maximum possible distance to preserve formation material. The ideal distance between adjacent perforations is achieved with same distances in all directions (Fig. 7.7).

Because of spiral charge spacing there is never a possibility to achieve that all distances are the same ($L_1 = L_2 = L_3$). So optimal solution is when any two of them are equal. Also the forth perforation spacing (L_4 – spacing between first and third wrap) must be considered to control the minimum perforation spacing.

When dealing with formations of high difference between vertical and maximal and minimal horizontal stresses the perforations should be oriented in the direction of maximum stability (Santarelli et al. 1991; Abbas et al. 1994). If there is a scope of uncertainty in the direction and the magnitude of the horizontal stresses and/or vertical to maximum horizontal stress ratio 0°/180° phased perforators should be used (Tronvoll et al. 2004). If the rate per perforation is a concern than for vertical wells perforations can be done in the direction of maximum perforation tunnel

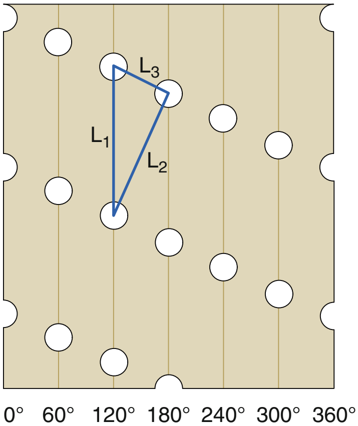


Fig. 7.7 Critical distances between adjacent perforations (Venkitaraman et al. 2000)

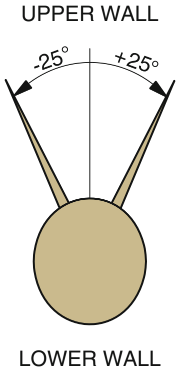


Fig. 7.8 Spacing of perforations in horizontal wells (Tronvoll et al. 2004)

stability with an angle of ±15–25°. For horizontal wells it should be up and down with the same spacing. If cleaning of the perforations is a problem the up perforations only can be done (Fig. 7.8).

Nomenclature

a_p	Perforation length, m
d_p	Perforation tunnel diameter, m
k_a	Permeability of the core in the axial direction, m^2
k_c	Permeability of crushed zone during jet perforating, m^2
k_d	Permeability of the core in the diametrical direction, m^2
k_p	Permeability of the perforation tunnel, m^2
k_s	Permeability of damaged zone, m^2

$L_1 = L_2 = L_3$	Distance between perforations, m
L_4	Spacing between first and third wrap, m
$NPPR$	Normalized perforation-permeability ratio
s_1	Skin due geometrical parameters
s_2	Skin/wellbore damage due to wellbore fluid invasion in the formation
s_3	Skin due compaction during jet perforating
SPM	Number of shots per meter
s	Total skin ($s_1 + s_2 + s_3$)
r_s	Radius of damaged zone, m
Φ	Gun phasing, degrees

References

Abbas HH, Meadows DL, Brumley JL, Hadeayati S, Venditto JJ (1994) Oriented perforations – a rock mechanics view, SPE 28555. In: SPE annual technical meeting, New Orleans, 25–28 Sept 1994

Bell WT (1984) Perforating underbalanced – evolving techniques, SPE 13413. J Pet Technol, October 1984, Vol. 36, No. 10, 1653–1662

Buzarde LE Jr, Karl RL, Bell WT, De Priester CL (1982) Lecture notes for: Production operations course 1: Well completions. In: SPE of AIME, Dallas

Bruist EH (1974) Better performance of gulf coast wells, SPE 4777. In: SPE symposium on formation damage, New Orleans, 7–8 Feb 1974

Chang FF, Mathiasen AM, Kageson,-Loe N, Walton IC, Svane G, Midtbo RE, Bakken I (2005) Recommended practice for overbalanced perforating in long horizontal wells, SPE 94596. In: SPE European damage conference, Scheveningen, 25–27 May 2005

Cheng MCA (1985) Perforating damage and shot density analyzed. Oil Gas J, March 4, 112–115, Vol. 83, No. 15

Jain S, Tibbles R, Munro J, Suppiah R, Safin N (2010) Effective perforating and gravel placement: key to low-skin, sand. Free production in gravel packs, SPE 140735. SPE Drill Complet 26 (1):60–67

Penberthy WL Jr (1988) Gravel placement through perforations and perforation cleaning for gravel packing. J Pet Technol February 1988, 229–236, Vol. 40, No. 2

Santarelli FJ, Ouadfel H, Zundel JP (1991) Optimizing the completion procedure to minimize sand production risk, SPE 22797. In: SPE annual technical conference and exhibition, Dallas, 6–9 Oct 1991

Tronvoll J, Eak A, Larsen I, Sanfilippo F (2004) The effect of oriented perforations as a sand-control method: a field case study from the varg field, North Sea, SPE 86470. In: SPE international symposium and exhibition on formation damage control, Lafayette, 18–20 Feb 2004

Venkitaraman A, Behrmann LA, Noordermeer AH (2000) Perforating requirements for sand prevention, SPE 58788. In: SPE international symposium on formation damage control, Lafayette, 23–24 Feb 2000

Walton IC, Atwood DC, Halleck PM, Bianco CB (2001) Perforating unconsolidated sands: an experimental and theoretical investigation, SPE 71458. In: SPE annual technical conference and exhibition, New Orleans, 30 Sept–3 Oct 2001

Well Servicing and Workover (1971) Well completion methods, Lesson 4. Petroleum Extension Service, The University of Texas at Austin, Austin

Chapter 8
Downhole and Surface Equipment

Contents

Abstract Completion as such is meant to be a link between drilling the borehole and the production phase. Without completing the well, hydrocarbons are not able to flow up hole under control. As a phrase, completion involves all the wellbore tools, accessories or tool assemblies involved in any wellbore operation. On the other hand, without proper surface equipment, which is one of the key factors for successful sand control operation execution, it is not possible to treat the fluid on the surface and pump it downhole.

This chapter is concentrated on sand control tools designed to prolong well life by eliminating sand production mechanically trapping it behind various downhole devices. All open or cased hole completions comprise of many different tools, accessories and devices like screens, packers, seal assemblies, running tools, blank pipes, safety joints, and other. They are introduced as an overview of possible tool

D. Matanović et al., *Sand Control in Well Construction and Operation*,
Springer Environmental Science and Engineering,
DOI 10.1007/978-3-642-25614-1_8,

combinations in certain occasions. Surface equipment consisting of mixers, pumps, blenders, filtering units and devices designed for treatment execution monitoring is presented as well.

8.1 Introduction

An efficient and successful sand control notably depends on well completion design and execution (i.e. drilling, casing cementing, perforating, downhole tools installation, etc.). To be able to properly design well completion many important data has to be considered, and that is reservoir pressure, temperature profiles, productivity index, water cuts, sand production volumes, formation damage, formation permeability, reservoir thickness and other. All of the mentioned has to be thoroughly investigated and affirmed as much as possible.

Once the wellbore has been drilled through the reservoir of interest, communication between the reservoir and the surface facilities has to be established through a certain pathway consisting of different tubular tools.

One of the most valuable downhole equipment tools are screens, formation sand filtering devices characteristic for gravel packing, standalone screen and frac-and-pack applications. But, other devices like packers, service tools, seal assemblies and other are also vital to perform any sand control operation.

For gravel packing and frac packing sophisticated and complex surface equipment and accessories is used as well. Equipment type is defined according to well location, terrain accessibility, rig floor area, well site area, and pressure and temperature ratings. There is another important factor considering equipment selection and that is funds availability. The more specialized equipment is used, the more money it is going to cost. Different completion types and methods demand different surface equipment. For example, if a standalone screen in open hole is to be installed, there is no need for casing cementation and gravel pack slurry pumping (surface mixers, blenders and pumps are not used). On the other hand, frac-and-pack operation design requires much more surface logistics to be used (truck pumps), not to forget cased hole expenses as well (Economides et al. 1994, 1997; Lake and Clegg 2007).

So, surface equipment and accessories consist of mixing and blending equipment, fluid and proppant storage equipment, transportation equipment, pumping equipment, filtering equipment and monitoring equipment.

8.2 Well Completion Tools and Accessories

Completion devices used in sand control applications in some proportions differ from regular production completions. What differentiates these two are downhole tools below the production packer. Sand control standalone or gravel packed completions involve special filtering devices (screens) used only in such applications (see Chap. 3) and service tool devices used for running the gravel pack assembly, fluids cross over and multipositioning inside the assembly for various flow paths. Some tools are run on wireline and the other ones on coiled or jointed tubing. Each of them has its own attributes and, if handled and treated properly within good operation design, they will not fail (Allen and Roberts 1989; Bradley et al. 1992).

8.2.1 Fluid Flow Control Devices

To achieve an even flow along the deviated sections of the wellbore and to choke it, *inflow control devices* (ICDs) are used. If the producing rates are abundant, such devices are installed on every premium screen joint over the producing interval length. This way the production rates can be controlled by means of average drawdown pressure regulation. ICDs have restricting elements which help to choke and distribute the fluid flowing pressure after entering the screen. Subsequently, passing through the inflow control device, fluid enters the inner pipe and up the hole to surface. ICD length is optional and depends on expected producing flowing pressure (i.e. reservoir simulation). No seals or any kind of moving elements are used so it makes it a very simple and reliable device.

Its application is possible in (Haaland et al. 2005):

- ***Horizontal wells with high productivity index to delay water or gas coning problems along the producing interval***,
- ***Water injectors***,
- ***Multilateral wells***,
- ***Wells with high viscosity oil production***.

Another useful flow control device is a *selective flow control screen* which is wire wrapped with closing/opening valve inside that has a sliding door. The valve is activated (closed) when pulling the wash pipe out of the screen and controls the flow through each screen joint providing for efficient zonal selectivity.

Some types of this tool include installation of nipples between screen sections. When water breaks through lower screen sections they can be isolated with plugs set inside the nipples. This way the upper sections are left non-waterflooded.

8.2.2 Packers

Packers are mechanical isolation devices used for wellbore fluids isolation (disabling communication between certain zones). Usually run with the production string, the main purpose of the packer is isolation of the annulus protecting it from aggressive formation fluids and thus corrosive action, maintaining the wellbore integrity. The main packer types used in petroleum exploration and production today are *mechanically set* (*compression and tension set*), *hydraulically set*, *wireline set*, and *swelling packers*. They can be either *retrievable* or *permanent*.

Sand control completions are composed in such a manner that a packer use is needed in every completion type (open hole, cased hole, gravel packed, standalone screens). Basically, all of the mentioned packer types can be used in such completions, but some of them are preferred for open hole and some for the cased hole completions. Packers used in cased hole completions are mainly mechanically and hydraulically activated packers generally not often applied in open hole. This section will concentrate on the packers best suitable for open hole deployment – *inflatable* and *swelling packers*, devices with excellent sealing possibility in cased or open hole within abnormal wellbore wall prominences (Bellarby 2009).

8.2.2.1 Inflatable Packers

These devices are specially designed hydraulically set packers having only supporting base pipe and inflating sealing element made of rubbery polymer material overlaid around the pipe (Fig. 8.1a). They are ideal for intervention operations

Fig. 8.1 Packer types used in open hole gravel packing applications. Inflatable packer (**a**) and swelling packer (**b**) (RIPE 2011; Halliburton 2011)

like sealing a huge open hole area after passing through a narrow completion, immediate zonal isolation, open hole gravel packing, etc.

To set the packer it is required to apply pressure through the setting string (tubing, casing, drill pipes) to inflate the sealing element. When the ball settles inside the valve seat, which is bellow the packer, fluid is directed into the sealing element through the check valve, which happens to be the only moving part of the packer assembly. When the element inflates, at certain pressure the ball seat breaks down and the communication between formation and setting string is established. Pressure inside the sealing element is maintained by the check valve not allowing the fluid to leak off (Halliburton 2011; Suman et al. 1983).

For the packer release it is enough to pull the setting string and the base pipe to uncover slot for pressure equalization.

8.2.2.2 Swelling Packers

Swelling packers based on swelling capability of their elastomers also provide for very effective seal in both open and cased hole applications. Basically, there are two types of swelling packer systems: *water swelling packers* and *oil swelling packers*. In the case of water swelling elastomers, swelling process is based on the principle of osmosis. Water enters the rubber matrix and swells the element until the equilibrium is achieved. Elastomer and the surrounding fluid (water) salinity levels are very important to consider as osmosis process depends on it. Any changes in downhole conditions and fluid properties can reverse the swelling process.

Oil swelling elastomers swell by the diffusion process – rubber molecules absorb the hydrocarbon molecules causing elastomers to stretch. Crosslinked polymer network of swelling packer rubber traps the hydrocarbon molecules due to their natural affinity. Reversible process is not possible. Unlike the other packer types, swelling packers deployment time can take few hours to several weeks, depending on the job design demands. Simple handling and well proven efficiency make this technological solution very promising for the future utilization.

Figure 8.1b shows the swelling packer with its belonging parts. It consists of *inner base pipe*, *bonded rubber* and *end rings*, used to direct the swelling rubber expansion perpendicular to packer and thus forcing it to seal the annulus (Halliburton 2011; Yakeley et al. 2007; Kleverlaan et al. 2005).

Swelling technology has an application in smart well, multilateral, gravel packing and multifracturing systems, providing for superb sealing necessary for zonal isolation when stimulating each of them in a row. In tandem with expandable screens technology, swelling packers can contribute to selective treatment of zones also allowing for greater space while interceding through tubing.

Unlike inflatable packers, ran on the drill string, swelling packers are set via completion assembly already having screens and other equipment attached. So, a substantial time (money) saving is notable.

8.2.2.3 Alternate Path Packers

Alternate path packers are devices used for zonal isolation of more than one layer providing propped slurry alternate path at the same time. They consist of *base pipe*, *sealing elements* and *rectangular or round tubes* (Shunt tubes) used for slurry transport to lower zones (Fig. 8.2a). Some versions of alternate path packers have isolation valves inside the shunt tubes for communication prevention after gravel pack operation is done. They are available in eccentric or concentric configurations to match with alternate path screens. Major benefits of this packer type are (Schlumberger 2011): (1) Washover and retrieval operations facilitation,

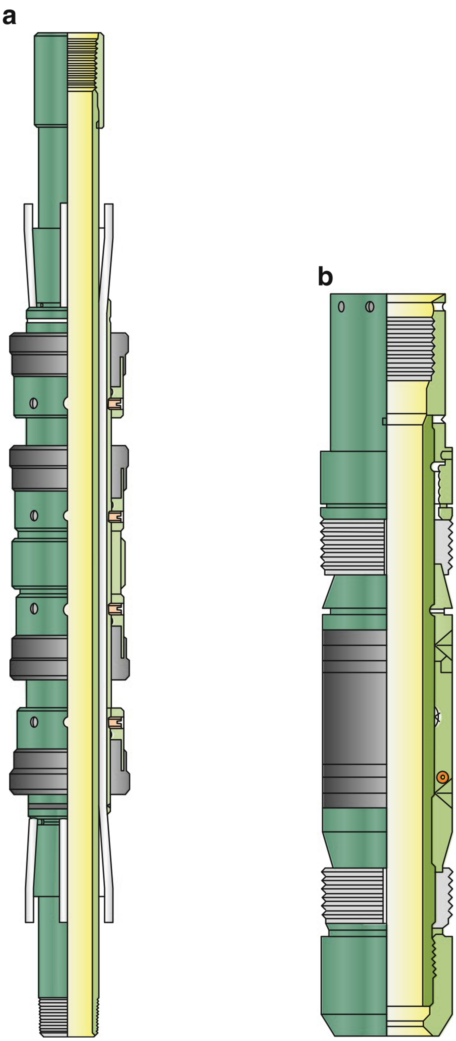


Fig. 8.2 Alternate path packer (**a**) and sump packer (**b**) (Schlumberger 2011)

(2) Completion costs reduction, (3) Gravel pack or frac-and-pack operations simplification, (4) No moving parts.

8.2.2.4 Sump Packers

Sump packers are sealing devices mainly used in cased hole sand control completions. They are usually set on wireline below the perforations depth to correlate the screen section positioning across the perforations and to serve as a base for sand control assemblies. Every sump packer (Fig. 8.2b) has sealing elements and anchoring grips for isolation of the system from lower sections. If screen to perforations overlapping is considered, sump packer should be set at least 4–5 m below the lowest perforation (Weatherford 2011).

Although sump packers are preferred in gravel packing operations there are some alternatives like *bridge plugs*, being a shorter devices also having isolation sealing elements. Bridge plug can be drillable or non drillable depending on what type of material are they made of. Sometimes, to serve as a base for the gravel pack assemblies, cement plugs are set instead.

8.2.3 Service Tool Assemblies

As a key device for gravel pack performance, service tool is a hydraulically activated tool assembly which runs the gravel pack assembly to desired depth and sets packer. It is actually a *crossover tool* with sealing elements for multi-positioning inside the screen assembly during operation performance. Each service tool position implies different circulation path so, for example, a four-position tool has:

- ***Squeeze configuration position***,
- ***Lower circulation position***,
- ***Upper circulation position***,
- ***Reverse circulation position***.

Squeeze position with closed annulus is acquired after the assembly run in, before the gravel packing. Its purpose is to pressure up the formation and induce the fractures (frac-and-pack method) before filling it with proppant laden slurry.

Lower and upper circulation positions are meant for the treatment pumping (either prepacking or main treatment pumping) with a live annulus (pressure is held at the surface). Reverse circulation position is shifted when the excess proppant needs to be reversed out of the well.

Crossover tool has gravel pack ports positioned at the tool middle with ball seat attached and bypass ports at the tool top. Ball seat with a ball in it allows for pressurizing the string to activate the packer. Further pressure increase blows the seat away leaving the gravel pack ports open. Crossover tool bears the whole assembly weight while running in (Ali et al. 2002).

Wash pipe is a thinner pipe attached to the crossover tool extending all the way to the screen bottom while running in. Its purpose is to collect the gravel packing fluid while gravel packing directing it up the gravel pack string, pass through bypass ports and up the tubing-casing annulus. Wash pipe top side has a ball seat for the ball to disable fluid back flow when gravel packing.

8.2.4 Seal Assemblies

To be able to properly connect gravel pack assembly and the packer, premium seal assembly has to be used. Such a device has couple of sets of sealing elements attached to the base pipe managing a tight seal. It is located below the screen joints and run as a part of gravel pack assembly after the sump packer or lower zone gravel pack assembly (in case of several zones treatment) packer deployment. The tool usually has a guiding mule shoe on the bottom for easier string stabbing into the packer (Baker Oil Tools 2002; Dusterhoft 1994; Halliburton 2011).

Some seal assemblies have *no-go locators* providing a positive locating stop for the string at the packer. A sufficient blank pipe spacing has to be provided between the no-go locator and sealing elements. Besides no-go locators, other tool types have a threaded *latching system* activated without the string rotation. Once activated, latching thread provides for seal movement prevention and good solids exclusion. It is released by pulling the string shearing the elements or rotating it.

Seals are made of premium elastomeric, plastic or alloyed materials able to withstand extremely high pressures and temperatures (HP/HT environment).

8.2.5 Safety Joints

Safety joints are most often located between the blank pipes and the gravel pack extension joints located below the production packer. Its purpose is to provide a disconnecting point and to allow retrieval of the packer leaving the screen assembly behind. It has breakable shear pins breaking at certain point of applied force when pulled. It is very useful when rotational release is not wanted as the seal assembly can be deployed via rotation as well. Safety joint is easily adjusted to compensate for hydraulic impacts existing in the string when running in or during the gravel pack treatment (OTIS 1991).

8.2.6 Blast Joints

Blast joints are tubular joints utilized in various well completions. As a part of production string, usually they are installed across the perforated intervals where the erosive flow of the formation fluids loaded with formation sand impairs the pipe wall. They can also be used directly below the wellhead to protect from the abrasion of doing a hydraulic fracturing or frac-and-pack operation by pumping the fluids downhole (Perrin 1999; Schlumberger 2011).

To resist all abrasive impacts of fluids and solids, blast joints outer diameter (OD) is larger then the rest of the tubulars. Inner diameter (ID) is mainly the same like other workstring components. This type of tubulars is made of heat-treated steel alloy emphasizing on abrasion and corrosion resistance (H_2S, CO_2, chlorides etc.).

Coiled tubing blast joints are basically meant for the same purpose like jointed tubing blast joints but with some adjustments on the joint size matter and thread types (premium quality threads used).

8.2.7 *Landing Nipples*

In order to satisfy measurement requirements, facilitate equipment installation or perform any other function, tubing has to be equipped with landing nipples designed to accommodate wellbore tools. There are several types of such devices: *full bore landing nipples*, *full bore selective landing nipples*, *full bore top no-go landing nipples* and *bottom no-go landing nipples* (Perrin 1999).

Full bore landing nipples have a locking groove and a seal bore. They do not restrict the fluid flow other then by their nominal diameter. They are run with a running tool which keeps the locking dogs on the mandrel retracted (Fig. 8.3a).

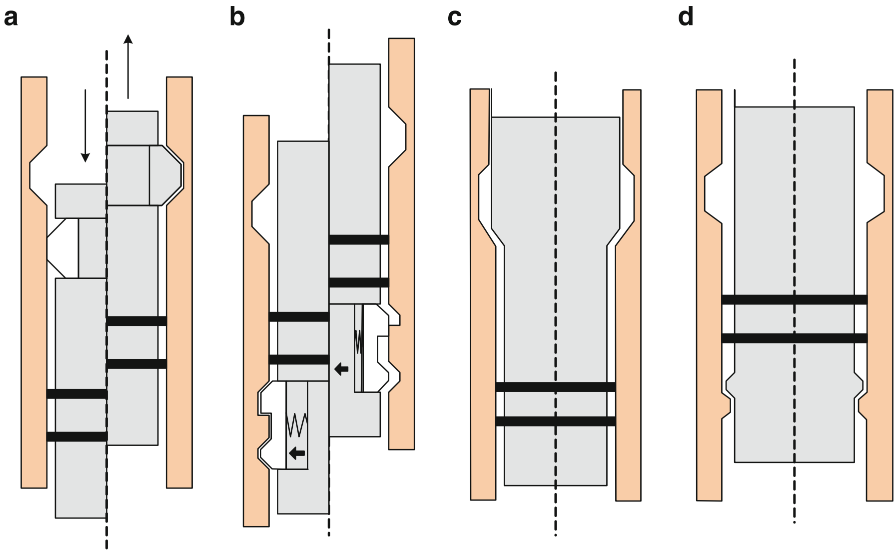


Fig. 8.3 Landing nipples (Perrin 1999)

Full bore selective landing nipples have different profiles, so only the exact key fits to a certain landing nipple. Special attention should be dedicated to landing nipple installation order along the string as some keys do not fit into certain nipples. The lowermost landing nipples have the least number of profile circles (Fig. 8.3b).

Full bore top no-go landing nipples have larger ID in the upper section and are used to hang completion tools (mandrels, tool assemblies, valves etc.) by not allowing them to pass the restricting point. These landing nipples are able to withstand up to 70 MPa of pressure (Fig. 8.3c).

Bottom no-go landing nipples have a machined shoulder at the base of the seal bore. It is called a bottom no-go (Fig. 8.3d). The principle is the same like top no-go nipple with the exception it is not full bore (mandrel fitting inside the nipple is of smaller OD then the nipple ID).

8.2.8 Ported Subs

Ported subs, as a part of gravel packing equipment, are widely used as selective circulation equipment. They are full opening devices with openings (gravel pack ports) on the tool body and inner sleeve or service tool extension with the ball seat. They can be closed or opened by using standard wireline procedures or service tool assembly. The purpose of this tool is to provide a communication between tubing and *tubing/casing* or *tubing/wellbore wall* annulus allowing slurry to flow freely. Usually they have nipple profiles above the inner sliding sleeve and a polished packoff area below as an integral part of the assembly (OTIS 1991).

At the beginning of gravel pack operation, ported sub ports are closed. Shifting the multipositioning tool (service tool) those ports are being opened for circulation with ability to perform prepacking or gravel packing operation. During the reverse circulation and production, gravel pack ports are closed preventing communication between the annulus and tubing. Figures 8.4 and 8.5 present tools cross section views by giving an example of a gravel packing procedure with gravel pack ported sub (Fig. 8.4) and through tubing sand control installations (Fig. 8.5) with all the tool parts involved.

8.2.9 Setting Shoes

Gravel packing assembly is greatly assisted by setting shoe or guide shoe which may or may not have ports at the bottom. Setting shoe with ports is called a wash down shoe (Fig. 8.4). Ports are designed for washing down through the wellbore and to circulate out excess materials accumulated at the ports entry. If the ports are redundant, a simple bull plugs are used. Ported shoes have a release mechanism for ports closure.

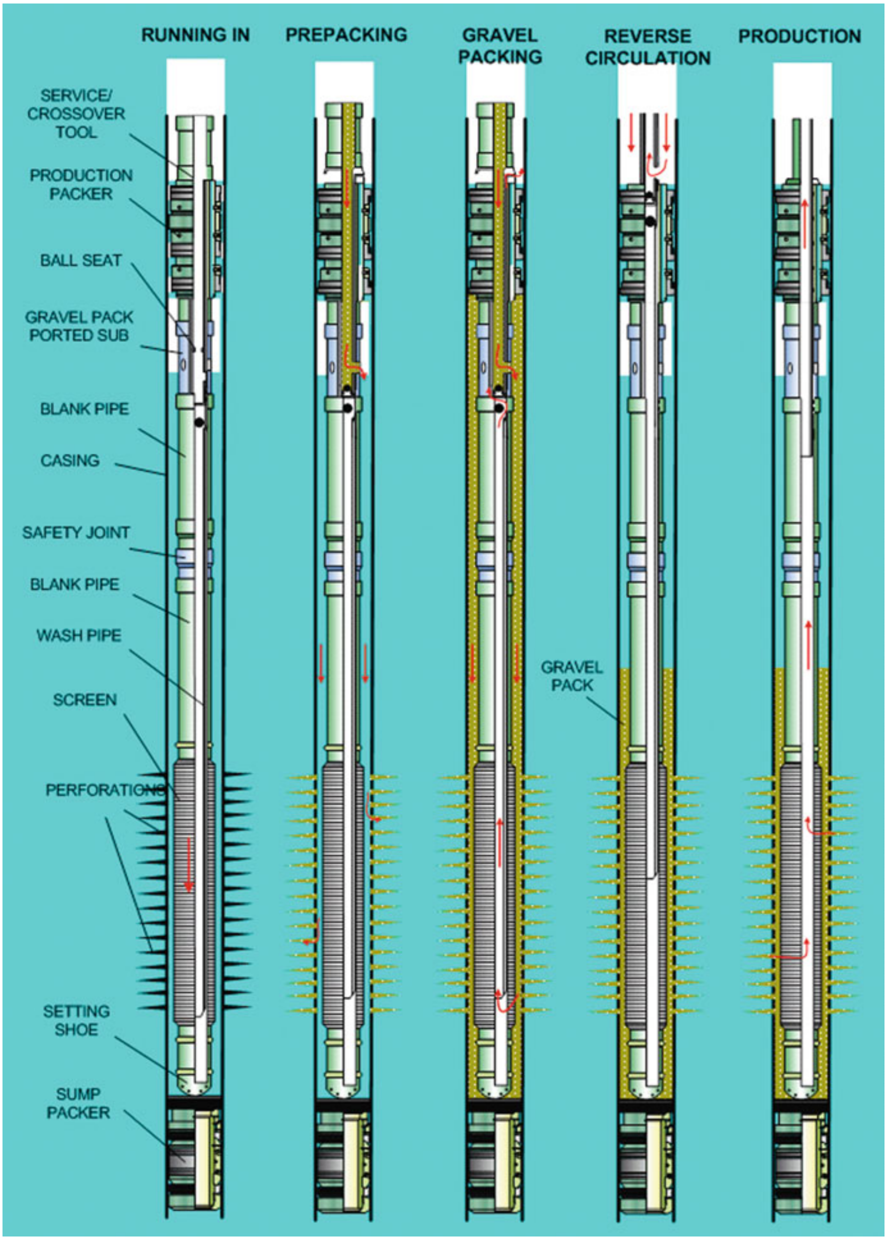


Fig. 8.4 A typical gravel packing operation procedure with the tools involved

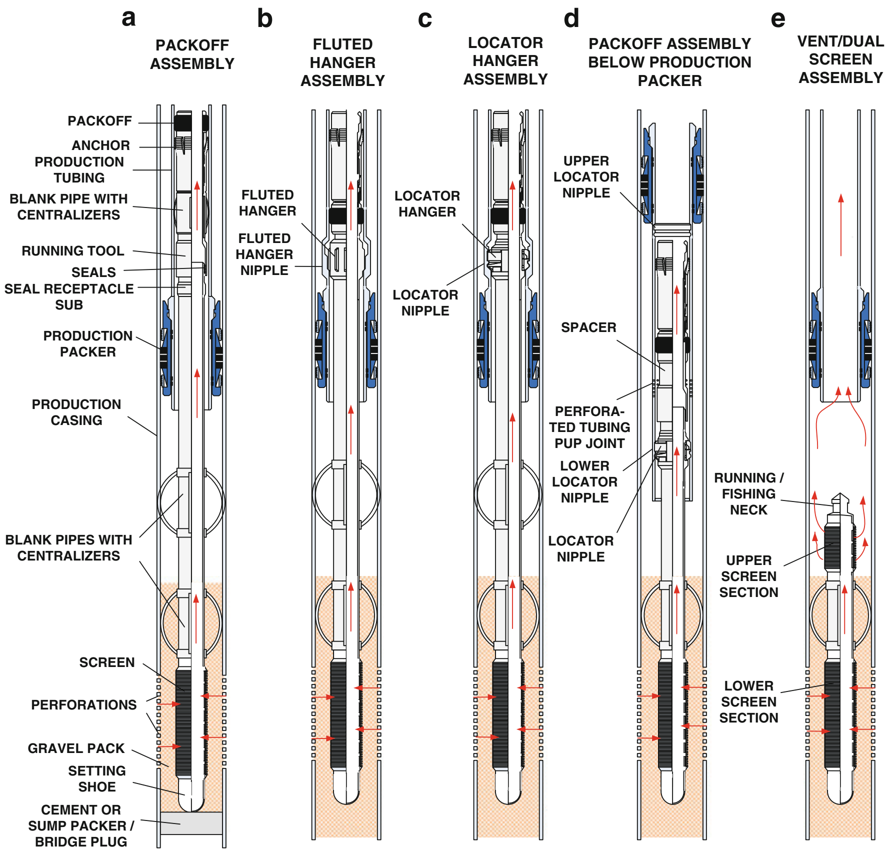


Fig. 8.5 Through tubing sand control possible installations with the tools involved (OTIS 1989; Restarick et al. 1991; Baker Oil Tools 2002)

When circulating through setting shoe ports an excessive fluid loss is possible so it is not always recommended to use ported shoes in open hole installations (Suman et al. 1983; Weatherford 2011).

8.3 Surface Equipment

8.3.1 Mixing Equipment

Before pumping the treatment slurry, proppant and the treatment fluid have to be mixed and prepared thoroughly to create unitary slurry having the same properties over the whole volume. There are many different types of mixing units, so they can be mounted on a skid (*batch mixer*), on a *truck* or on the *trailer* as shown in Fig. 8.6a, b.

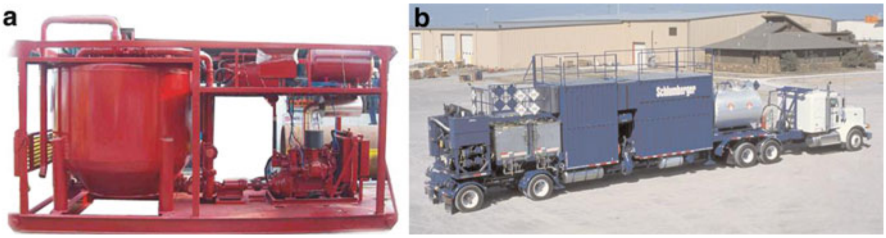


Fig. 8.6 Skid mounted batch mixer (**a**) and truck/trailer mounted mixer (**b**) (Sparklet Engineers 2011; Schlumberger 2011)

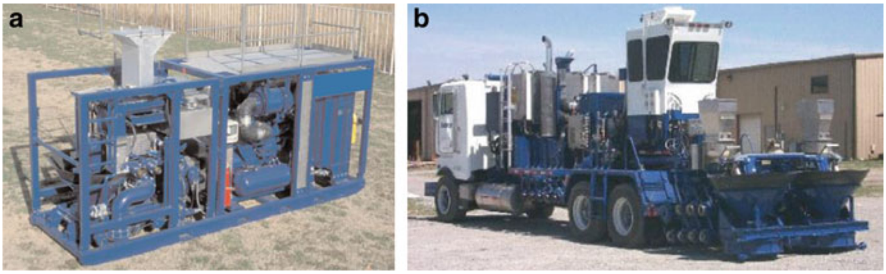


Fig. 8.7 Skid (**a**) and truck (**b**) mounted blender (Schlumberger 2011)

If the operation is not rate and pressure demanding, smaller skid mounted batch mixers are used providing economical mixing capability. If demanding jobs are encountered, additional units are added to assure adequate mixing space. *Mixing equipment* usually consist of a tank with mechanical agitator adjusted to effectively agitate additives and brine without unwanted air bubbles occurrence. Centrifugal pumps are used to run them.

After batch mixing and liquid gel addition, fluids are transported to *blenders* where proppant is added and mixed with treatment fluid. The slurry is ready for pumping when it achieves desired properties (density, viscosity, proppant concentration etc.). It is recommended to filter the gelling agent inside the *filtering unit* (see Sect. 8.3.4) and set it free of any kind of sludge before agitating to slurry. Blenders are also either skid or truck mounted (Fig. 8.7a, b), but some types include even combinations with truck mounted pumping unit (Schlumberger 1992; Ott and Woods 2003).

Mixing tank units needed on site are sometimes numerous depending on fluid types to mix separately. If several tanks are used for the same fluid, they can work simultaneously – while one is forwarding the mixed fluid, other ones are preparing the same. Limited number of tanks can be a problem, so after mixing one fluid type and transporting it to another container, other fluids are free to mix when the tank is properly cleaned and rinsed. But, to avoid confusion and units lack, after the operation design, all required logistics are ordered in advance to make sure it will be provided. These units are made of stainless steel to prevent rusting.

Sometimes, certain treatments cannot be handled with standard mixers and blenders, especially when long intervals are encountered requiring large amounts of gravel or in case when different slurry densities and proppant concentrations are needed. Units with computerized properties control continuously monitor and adjust concentrations of additives and proppant addition to make job performance easier and decrease human error possibility. More of monitoring and control equipment will be mentioned later on.

8.3.2 Materials Storage and Transport Equipment

To store any kind of chemical means to follow all environmental and governmental policies regarding chemicals handling and storage. Storage equipment should provide safe materials conservation separating it from other reactive materials and preserving.

Liquids are usually stored in various *tanks* or *trailer type containers* meant for the transport as well, like shown in Fig. 8.8a. Corrosion resistance is one of

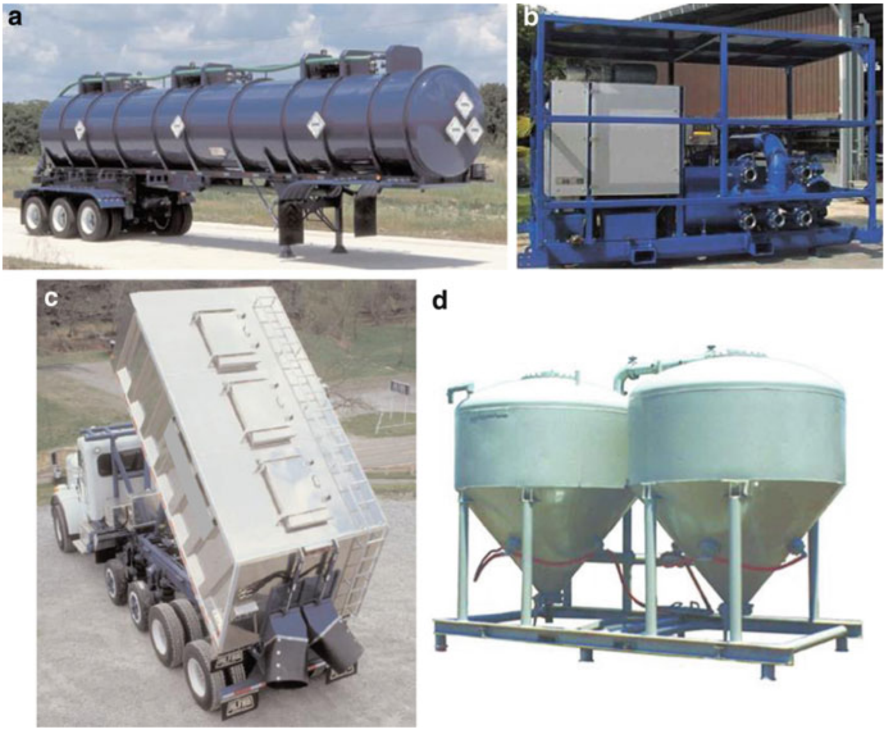


Fig. 8.8 Proppant and fluids storage and transport equipment (Schlumberger 1992, 2011; Halliburton 2011). (**a**) Trailer type liquids tank. (**b**) Centrifugal pump. (**c**) Proppant transport truck. (**d**) Proppant silo

conditions containers must apply, so carbon steel outer layers help to maintain corrosion under control. Tank discharge outlets are situated at the bottom rear of the tank with installed valves for flow control. Fill manifold is affixed at the rear side also, with a vacuum breaker equalizing air pressure during fluid unloading. Every tank needs a relief valve for over pressurizing control and vent outlets for discharging redundant or dangerous fluids.

For proppant storage horizontal (trailer type) or vertical units, *silos*, are used (Fig. 8.8d). If available, vertical ones are preferred because of space preserving. Modern vertical proppant silos reduce space required for proppant storage, increase storage volumes comparing to traditional units, improve proppant weighing capability (more precise material inventory) and generally are more reliable as a result of silo main controlling panel installation. Suction and discharging lines are controlled via separate manifolds (Halliburton 2011; Dusterhoft 1994).

Constant delivery of proppant to the blenders is crucial for the job success. *Truck driven tanks* (Fig. 8.8c) used for storage are in transportation service as well, especially *trailer mounted tanks*. Offshore proppant storage and transportation requires certain limitations inclusion, which are limited space, weight and height. So, mainly, vertical type of silos and other units are used, with limited volume of fluids and proppant to accommodate. Proppant delivery systems effectiveness can be measured by radioactive densometer located inside the discharge line. Some adjustments to proppant flow during treatment operation are allowed to be made.

Centrifugal pumps are used for pressurizing and transport of treatment fluids during operation. They are allocated on their own skids with protective frames (Fig. 8.8b). These pumps are powered by diesel engine also residing on the same skid. Suction and discharge outlet valves are manually or hydraulically operated depending on unit's equipment package (Schlumberger 1992).

8.3.3 Pumping Equipment

Pumps used in gravel packing and frac-and-pack operations are almost the same like pumps used in other services. They are diesel powered triplex pumps mounted on a skid or truck (Fig. 8.9a, b) rated to more than 1,500 kW of power capable of inducing pressure to more than 140 MPa (Ott and Woods 2003). Quintuplex pumps are used when higher flow rates are necessary.

Secondary pumping unit also has to be ready for continuous smooth operation if a primary unit malfunctions. Sometimes, attached displacement tanks are used for better control of displacement volumes when pumping.

The unit itself has a feed line which extends from the blenders and high pressure pumping line going to the well. A return line from the pump feed manifold to the blenders has to be installed as well to allow slurry to be transported through the suction line at higher velocities (used only when pumping at low velocities).

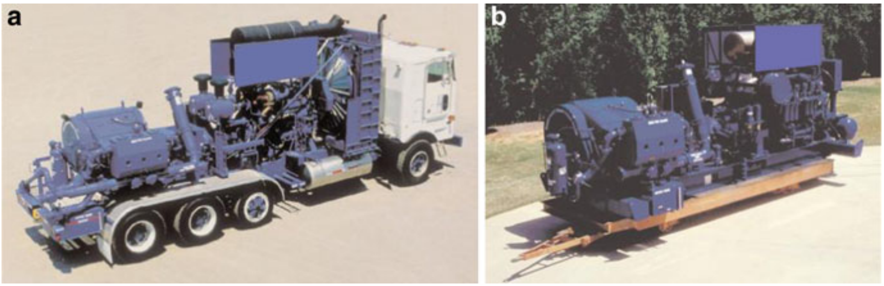


Fig. 8.9 Treatment truck mounted pumping unit (**a**) and skid mounted pumping unit (**b**) (Schlumberger 1992, 2011)

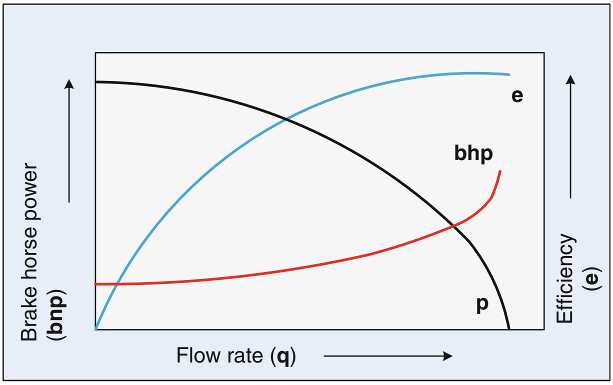


Fig. 8.10 Chart used for determining actual pump hydraulic horse power (Ott and Woods 2003)

Today, modern pumping units are computer controlled and all unpredicted malfunctions are recorded and immediately stopped. Pumping rates and pressure control are electronically adjusted at the beginning of the treatment.

When talking about pumping unit power, one has to differentiate horse power (hp) from actual hydraulic horse power (hhp). Horse power is the energy a pump can supply to move the slurry. On the other hand hydraulic horse power is the actual power used to move the slurry which is calculated by multiplying the brake horse power (bhp) with efficiency factor *e* (Eq. 8.1) (Ott and Woods 2003):

$$hhp = e \cdot bhp \tag{8.1}$$

Brake horse power is the power supplied to the pump by the engine. Figure 8.10 shows how to determine actual pump hydraulic horse power combining it with the equation above. For optimum flow rate (q) and pumping pressure (p), brake horse power (bhp) and efficiency factor (e) are determined; hhp is then easily calculated using the above mentioned equation.

Upon any pumping job start (gravel packing and frac packing is no exception), a pressure test should be done on the pumping unit to test the pumping lines connecting pump with the wellbore. Fluid leakage during the test implies on improper lines connection or old, damaged, even wrong size or type of equipment installed.

Sometimes, to acquire desired pressure while frac packing deep high pressure reservoirs, numerous pumping units are used.

8.3.4 Shearing and Filtering Equipment

Every treatment fluid preparation starts with mixing and agitating in clean tanks. Clean fluid preparation is vital for efficient gravel pack or frac-and-pack job performance. Thorough mixing is also of great importance, as gel lumps not dissolved properly in the mixing fluid might be dangerous with potential to plug the packed gravel. Shearing the polymer fluids helps to hydrate and viscosify the gel. Those way non-hydrated polymers are almost eliminated for effective filtration. Basically, shearing devices consist of impeller or rotating flow splitter. The latter are designed to split and rejoin the stream few times during fluid pass. Multiple passes provide shearing of larger fluid amount. More often, only a simple choke is used to replace the shearing unit.

It is of major importance to have solids free fluid when starting a gravel pack or frac-and-pack treatment. Solids may come from pumps, flow lines or improperly cleaned tanks. To set the treatment fluid (brine) free of solids various *filtering units* are used (Schlumberger 1992):

- ***Cartridge filter***,
- ***Bag filter***,
- ***Tubular cartridge filter***,
- ***High rate filter***,
- ***Diatomaceous earth filtering system***.

A combination of these filters is the most efficient way of filtering the fluid, but either of these used alone would provide satisfactory filtration.

Cartridge filter unit is one of the oldest devices in oil industry doing filtration tasks. It filters solids from the fluid containing below 100 ppm of total suspended solids. Skid or trailer mounted types are the most common, with two vessels manifolded together. If one of the vessels has to be changed, other one continues to work. During the filtration process dirty fluid enters the vessel containing filtering elements which are designed to free the fluid out of solids. Clean fluid comes out of the vessels into the clean fluid tank. Pressure rating of these units is set to maximum of 0.7 MPa.

Bag filter unit consists of mesh fabric bags mounted in housing. Dirty fluid comes from above going through the bag centre and support liner to the void space in housing. Trapped solids remain in the bag and the fluid filtrate comes out through the exit port on the lower side of the housing.

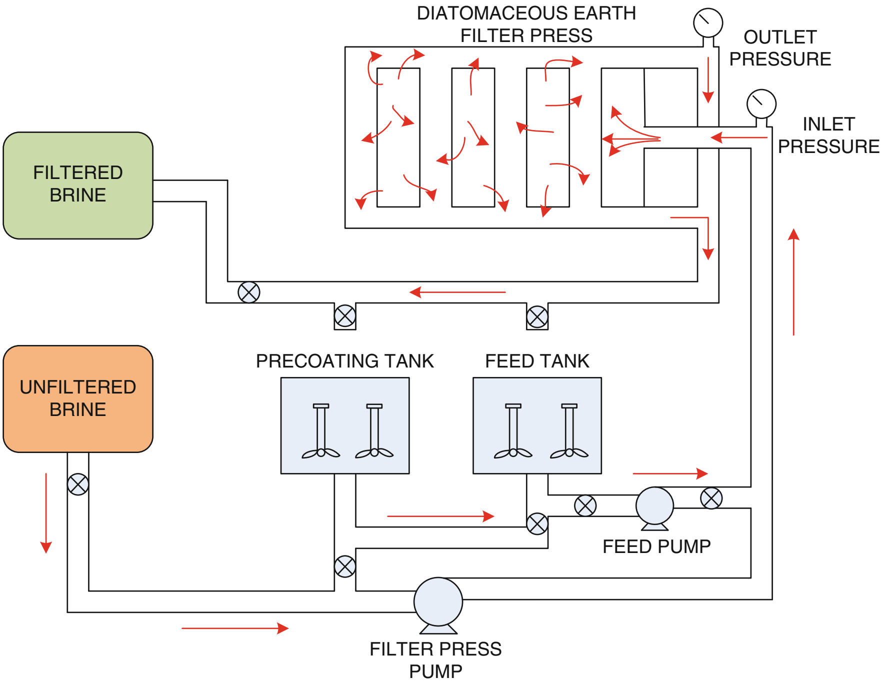
The bags used for this unit are made of silk, wool, nylon, polyester, polypropylene or rayon. They are very cheap which makes it a low cost filtering technique.

Tubular cartridge filter units are made within strict standards of the size of filter fiber and the tightness of the filter weave. Several filtering layers are introduced- outer layers for larger particles filtering and inner layers mounted for smaller particles removal. This type of layered filtering technique maintains effective permeability of the filter for long time and thus no frequent filter changing is required.

High rate filter units, as the name itself says, are cartridge type filters able to filter large amounts of fluid in a unit of time.

Diatomaceous earth filtering system requires coating a filter cloth with a porous filter and then using the pore spaces of diatomaceous earth filter cake as a filter. The smaller diatomaceous earth particles the higher filtration quality. Basic operations of this filtering system are *precoating cycle*, *filtration feed cycle* and *cleanout cycle* (Fig. 8.11).

In precoating cycle a certain amount of diatomaceous earth is mixed and pumped several times through the filter cloth. As the slurry circulates through the filter, particles bridge off being trapped on the cloth. Eventually, all of the diatomaceous earth becomes trapped in the filter resulting with clean effluent.



100.43

Fig. 8.11 Diatomaceous earth filtering system overview (Baker Oil Tools 1985)

When the precoating is done, unfiltered fluid is passed through the system. As the filtration process continues, additional amount of diatomaceous earth is continually added from the feed tank to the main stream (filtration feed cycle). Purpose of this cycle is to maintain a consistent permeability in growing filter cake. It is necessary because the suspended solids of unfiltered brine can form impermeable cake which can diminish the duration of filtration. Once filtered, additional diatomaceous earth will aid in building of the filter cake and filtration efficiency.

The final cycle is cleaning process. This happens at the end of the filtration cycle. Reduced flow rate and high pressure differential across the filter are indications that this step should begin. The result from the formation of either is a complete filter cake or an impermeable zone within an incomplete filter cake. Compressed air replaces the brine (filter press) in the flow path and each filter cake is purged of residual brine. Cleaning is done by separating the plates of filter press. The dried filter cakes separating from the cloths are removed from the plates and disposed off. Cloths and plates are then being washed, repressed and the precoating cycle can begin (Baker Oil Tools 1985).

Solids removal should be available upon every gravel packing or frac packing operation on each wellsite. Larger particles should be removed by settling tanks, shakers having screens, mud cleaners, desilters, desanders, or bag filters. Small particles should be removed by fine filters described in this section.

Filtering polymer based fluids serves to further removal of non-hydrated polymers. This results in increasing fluid leakoff properties and reducing the permeability damage. Shearing and filtering together reduces the fluid viscosity 5–10% (Schlumberger 1992; Halliburton 2011; Dusterhoft 1994).

8.3.5 Monitoring Equipment

When pumping fluids, treatment pressures, rates, proppant concentrations, chemicals mixing concentrations, fluids physical properties, and other are monitored constantly at all times as it is an important aspect of operations quality control. All devices are connected to the main computer which records and correlates the treatment parameters. Hundreds of different parameters can be monitored and adjusted real-time with computer systems nowadays. As technology progresses, every once in a while a new monitoring system comes out to market offering an innovative solutions for well stimulation and sand control.

Standard portable monitoring equipment which should be available on every rig upon every well stimulation and sand control operation is (Schlumberger 1992; Halliburton 2011):

1. ***Densitometers*** – digital devices used for fluid density measurement. There are two types of densitometers depending on environment working pressure- *low* and *high pressure*. High pressure densitometers are able to withstand pressures up to 7.0 MPa and provide correct real-time measurement.

2. ***Flowmeters –*** are high pressure portable assemblies used for fluid flow measurement (fluid volume per unit of time) made of durable alloys for great strength and erosion resistivity. They are easy to use because of its simple installation to flow line. Flowmeters improve operation effectiveness by real-time monitoring the flow values through the treating lines.
3. ***Return tank sensors–*** are meant for measurement of treatment returning fluid volume. Slurry volume returning to surface has to be correctly measured and settled gravel weighted to be aware of what has left downhole. Every return tank should have a manifold for directing, bypassing fluids or shutting down certain line routes.
4. ***Gravel pack manifold–*** is a main manifold for fluid directing downstream or when returning back to surface. It consists of valves and pressure sensors for monitoring and adjustment of back pressure.
5. ***Special measuring devices–*** are portable kits able to measure main fluid rheological properties, gravel size, fluid leak off and additive concentrations. Its purpose is to measure all these properties on site to be sure all design parameters are well introduced.

8.4 Equipment Pressure and Temperature Rating

Additional hydrocarbon production is sometimes hard task to achieve if extreme conditions of pressure and temperature are encountered (HP/HT – high pressure and high temperature conditions). Although the well completion in such conditions is basically done the similar way like in "normal" conditions (i.e. <69 MPa and <423 K), they limit the possible combinations of completion tools rated to lower pressures and temperatures. If we would like to classify general pressure and temperature ratings in the well, it would look like the following (DeBruijn et al. 2008):

- ***Normal pressure and temperature***– up to 69 MPa and 423 K,
- ***Enhanced pressure and temperature–*** up to 138 MPa and 478 K,
- ***Extremely high pressure and temperature–*** up to 241 MPa and 533 K,
- ***Ultra high pressure and temperature–*** more than 241 MPa and 533 K.

Downhole tools are very much affected by high pressures and temperatures so every change of these conditions might cause permanent damage or low efficiency. As it is known that every pressure and temperature change impacts the tool integrity and length change, materials used for downhole tools make have to be of such quality, resistivity to withstand huge stresses.

Some of today's modern and innovative materials used are the following:

- ***Polymer resins strengthened by glass fibers***,
- ***Carbon fiber alloys***,
- ***Nickel alloyed chromium steel***,
- ***Aluminum, wolfram, molybdenum, manganese and titanium alloys***.

8.4.1 Temperature and Pressure Impact

Medium high or high temperature affects the tools mechanical properties. When introduced to high temperature, molecules of the tool material start moving around faster, molecule connections become weaker and the material softens evidently. Consequences of such exposure are numerous, including possible tool breakage, bending, bursting and aggressive corrosion induced by H_2S or CO_2.

One of the most important steel properties is capability of the structure change due to temperature rise and every steel microstructure particle contributes to final steel product properties. Basic steel structures are:

- ***Martensitic***,
- ***Austenitic***,
- ***Ferritic***.

Rubbery sealing elements are influenced by the high temperature as well. They tend to deteriorate and finally fall apart if not made of resistant material.

Various pressure fluctuations inside the wellbore during drilling, production, stimulation or well killing operations sometimes cause extreme stresses in downhole tools. Length and diameter change is then inevitable. Shorter subs and tools also elongate but negligible. *Piston effect*, *buckling*, *ballooning* and other applied forces are caused by pressure changes and they impact elongation and degradation level of the tools.

8.4.2 Equipment Rating

Equipment maximum working temperature and pressure barriers are some of the guidelines to consider when designing gravel pack or frac-and-pack operation. Every piece of equipment has its own recommended and maximum working temperature and pressure rating which is crucial when planning a demanding operation (hydraulic fracturing, for example).

Intermediate and high pressure equipment incorporate a wide array of different metals. For permanent equipment, desired material for many completion parts is 4140 steel. This material has a minimum yield strength of $5.52 \cdot 10^8$ Pa (80,000 PSI) and is suitable for use in most hydrogen sulfide environments. But, some parts require higher stress levels than this material allows and the heat treating required to get high strength makes 4140 steel unacceptable for service in H_2S conditions. Stainless steel, grade 410, or inconel 625 (highly corrosion resistant nickel alloy) is used in these cases. Ductile cast iron is very brittle, strong and easy millable, so it is used in some packer parts meant for being milled.

Low pressure equipment is mainly made of 1018 or 1040 carbon steel with yield strength of $2.76 \cdot 10^8$ Pa (40,000 PSI) to $4.14 \cdot 10^8$ Pa (60,000 PSI).

This relatively low strength is appropriate for low stresses required from low pressure equipment. Although the weight of the gravel pack equipment used for long intervals may be high, it is usually associated with large tubular, so the material stress is relatively low.

Tubing workstring and blank tubing pipes quality has to be strong enough to withstand all imposed pressures during treatments (especially frac-and-pack method), meaning that often used steel grades are T-95, P-110 and Q-125 with corresponding yield strength of $6.55 \cdot 10^8$ Pa (95,000 PSI), $7.58 \cdot 10^8$ Pa (110,000 PSI) and $8.62 \cdot 10^8$ Pa (125,000 PSI).

The most popular tubing connection type today is VAM (Valuorec and Mannesmann) with yield strength going up to 1,034 MPa (double threaded connections for extreme downhole conditions). Long double threads have the ability to preserve workstring stiffness accounting for good buckling resistivity.

Packers have to resist huge pressure differentials when working deep. Plus, corrosive actions of some formation fluids distract efficient packer sealing ability. Packer bodies impregnated with titanium, manganese, molybdenum or wolfram and rubbery sealing elements made of carbon fibers are not unknown practices today. These improvements provide for up to 573 K temperature resistance and 138 MPa of differential pressure. Some swelling packers with 70 MPa pressure differential sealing ability are not among the top pressure rated packers (mechanically and hydraulically set) but proof to be reliable within this pressure margin. Packers, liner hangers and similar equipment are designed to be of higher strength than the tubular equipment, mostly able to persist 9,500 Nm of torque.

The most commonly used elastomer in gravel packing equipment is made of nitrile rubber (NR). Elastomers differ from nitrile rubber composition and vulcanization conditions point of view. The major limitations to its use are temperature and presence of hydrogen sulfide. Today, elastomers are able to withstand even 550 K of temperature (Baker Oil Tools 1985).

Screens are in general made of high quality materials capable of resisting extreme erosion and corrosion (see Sect. 3.2.2). Wires and tubes can be made of low-carbon steel, 304 or 316 stainless steel, monel, inconel or other. Temperature rating is set quite high, to 477–644 K (Suman et al. 1983).

Nomenclature

bhp	Brake horse power, W
e	Pump efficiency
hhp	Hydraulic horse power, W
hp	Horse power, W
p	Pumping pressure, Pa

References

Ali S, Norman D, Wagner D, Ayoub J, Desroches J, Morales H, Price P, Shepherd D, Toffanin E, Troncoso J, White S (2002) Combined stimulation and sand control. Oilfield Rev Summer 14:30–47

Allen TO, Roberts AP (1989) Production operations: well completions, workover and stimulation, 3rd edn. Oil & Gas Consultants International, Tulsa

Baker Oil Tools (1985) Baker sand control catalogue: Perforating, gravel packing and stimulation. Baker Oil Tools Company

Baker Oil Tools (2002) Sand control systems. Baker Hughes, Houston

Bellarby J (2009) Well completion design, vol 56, Developments in petroleum science. Elsevier, Hungary

Bradley HB, Gipsin FW, Odeh AS, Sizer PS, Mortada M, Raymer LL, Smith GL (1992) Petroleum engineering handbook. Society of Petroleum Engineers, Richardson

DeBruijn G, Skeates C, Greenaway R, Harrison D, Parris M, James S, Mueller F, Ray S, Riding M, Temple L, Wutherich K (2008) High-pressure, high-temperature technologies. Oilfield Rev Autumn 2008, Vol. 20, No. 3

Dusterhoft RG (1994) FracPac completion services-stimulation and sand-control techniques for high-permeability oil and gas wells. Halliburton Energy Services, Houston

Economides MJ, Hill AD, Ehlig-Economides C (1994) Petroleum production systems. Prentice-Hall TPR, Upper Saddle River

Economides MJ, Watters LT, Dunn-Norman S (1997) Petroleum well construction. Wiley, Duncan

Haaland A, Rundgren G, Johannessen Ø (2005) Completion technology on troll-innovation and simplicity. In: Offshore technology conference, paper OTC 17113, Houston

Halliburton (2011) Online brochure manual. http://www.halliburton.com/ps/default.aspx?navid=5&pageid=175&prodgrpid=MSE%3a%3a1045774737549167www.slb.com

Kleverlaan M, Van Noort RH, Jones I (2005) Deployment of swelling elastomer packers in shell E&P. In: SPE/IADC drilling conference, paper SPE/IADC 92346, Amsterdam

Lake LW, Clegg JD (2007) Petroleum engineering handbook: production operations engineering, vol IV. Society of Petroleum Engineers, Richardson

OTIS Engineering Corporation (1991) Sand Control: Equipment and Services. Products and services catalogue, Otis Engineering Corporation Printed, USA

Ott WK, Woods JD (2003) Modern sandface completion practices handbook, 1st edn. Gulf Publishing, Houston

Perrin D (1999) Well completion and servicing. Institut Francais du Petrole, Paris

Restarick Jr HL, Fowler Jr SH, Sedotal WP (1991) Through-tubing sand-control techniques reduce completion costs. In: 1991 SPE offshore Europe conference, paper SPE 23130, Aberdeen

RIPE (2011) Online brochure manual. http://www.rripe.com.au/downloads.html

Schlumberger (1992) Sand control engineering manual, vol 1, Schlumberger Company Course Notes

Schlumberger (2011) Online brochure manual. http://www.slb.com/services/completions/sand_control.aspx

Sparklet Engineers (2011) Online brochure manual. http://www.sparkletengineers.com/cement_bulk_plant_equipments.html

Suman GO Jr, Ellis RC, Snyder RE (1983) Sand control handbook, 2nd edn. Gulf Publishing, Houston

Weatherford (2011) Online brochure manual. http://www.weatherford.com/Products/Completion/SandControl/index.htm

Yakeley S, Foster T, Laflin W (2007) Swellable packers for well fracturing and stimulation. In: Paper SPE 110621-MS, SPE annual technical conference and exhibition, Anaheim, 11–14 Nov 2007

Index

D. Matanović et al., *Sand Control in Well Construction and Operation*, Springer Environmental Science and Engineering,
DOI 10.1007/978-3-642-25614-1, © Springer-Verlag Berlin Heidelberg 2012