6.2.1 Introduction

Petroleum production engineering is the series of activities concerned with the ability of a well to produce or inject, often described through a productivity or injectivity index (i.e., produced or injected volumes per unit time per differential pressure drop in the near wellbore region). As such, there is a difference between reservoir engineering, which deals with the reservoir-at-large and, in particular, the extent and timeliness of hydrocarbon recovery. Production engineering often deals with one or more wells at a time, and the delivery of oil and gas from the wellhead to the point-of-sales (Figs. 1 and 2). More important is the frequent over-riding economic motivation to accelerate the production by increasing the well production or injection rate. Terms such as production enhancement and well stimulation have been coined and used extensively. At times, equally important, is the reduction of the well drawdown, i.e., the difference between the driving, reservoir pressure, and the flowing bottomhole pressure.

Fig. 1. Petroleum production system: elements affecting well productivity.
While on a superficial basis, the lower the flowing bottomhole pressure the larger the production rate would be, this situation is not always desirable. There are many adverse effects associated with lower flowing bottomhole pressure such as scale, paraffin and asphaltene deposition, water and/or gas coning and sand production. Thus, it is essential that it is understood from the outset that stimulation and the presumed increase in the productivity index should not automatically translate into increasing the well production rate but, instead, allocate the appropriate portion of the productivity index increase to production rate increase and/or drawdown decrease, depending on the needs of each individual well. Therefore, production optimization goal is to increase productivity and improve the overall asset value (in the short-term) while satisfying all physical and financial constraints.

An integrated productivity enhancement approach, with reservoir management, balances the short-term production optimization and the long-term reservoir engineering objectives, in order to produce far more rational effects in the field development.

Reservoir management is about making the best possible decisions that will enable a company to meet specific objectives; and implementing these decisions. The ability to make the best possible reservoir management decisions relies mainly on the ability to predict the consequences of implementing these decisions. This, in turn, depends on the ability to model the expected behaviours of the reservoir system. The most common objectives of reservoir management are: to decrease risk, to increase oil and gas production, to increase oil and gas reserves, to maximize recovery, to minimize capital expenditures, to minimize operating costs and to optimize profitability. The understanding of reservoir management has improved greatly over the last few years and a methodology is slowly emerging to facilitate its routine implementation. Reservoir management used to be identified with production engineering, and then became synonymous with
numerical reservoir simulation. It is now understood that it is an iterative process, of which numerical reservoir simulation and production engineering are only two components.

**Basics of petroleum production system**

Fig. 1 shows the different components of the petroleum production system. An integrated, rather complex interaction of reservoir inflow, flow through perforations and tubing outflow, well choke, surface pipelines and separators, are the components of the petroleum production system.

**Flow rates**

The one-phase steady-state inflow performance of a reservoir for the oil flow rate \( q \) (in STB/D, Stock Tank Barrel/Day) is given by Eq. [1], which assumes under-saturated conditions (gas in solution), constant reservoir pressure, \( P_w \), at a certain border distance, \( r_w \), and accounts for the pressure losses (basically permeability impairment due to drilling and completion damages) near the wellbore due to damage to the formation, known as a skin effect.

\[
q = \frac{k h (P_w - P_{wof})}{141.2 B_o \mu_o \ln \left( \frac{r_e}{r_w} \right) + s}
\]

where \( k \) (md) is the effective formation permeability, \( h \) (ft) the formation thickness, \( P_{wof} \) (psi) the flowing bottomhole pressure, \( s \) the skin factor, \( r_w \) (ft) the wellbore radius, \( B \) (RB/STB) the oil formation volume factor. Assuming that reservoir and near-wellbore pressure remain above bubble point, the expressions for the flow of oil \( q_o \) and water \( q_w \) should be expanded to account for the relative permeability reduction due to the effect of each phase's saturation, thus obtaining the following relations:

\[
q_o = \frac{k_{rw} h (P_w - P_{wof})}{141.2 B_o \mu_o \ln \left( \frac{r_e}{r_w} \right) + s}
\]

\[
q_w = \frac{k_{ro} h (P_w - P_{wof})}{141.2 B_o \mu_o \ln \left( \frac{r_e}{r_w} \right) + s}
\]

where \( k_{rw} \) and \( k_{ro} \) are, respectively, the permeability with respect to water and to oil in a two-phase reservoir. The larger the water saturation near the wellbore, the lower the oil flow.

**Skin effect**

This term accounts for the additional pressure drop necessary to overcome the flow resistance of the reduced permeability zone caused by drilling mud invasion, the effect of partial penetration or the effect of the penetrating contact angle of the well architecture. Fig. 3 shows the radius \( r_s \) of the zone characterized by the skin with respect to the drainage radius. The skin factor \( s \) can be related to formation and damage permeability \( k \), damage penetration \( k_s \) and well radius \( r_w \) by \( s = (k/k_s - 1) \ln(r_s/r_w) \).

**Productivity index**

The productivity index \( J^* \) (BOPD/psi) above the bubble point pressure \( p_{b} \), when there is no water production, is the ratio between the oil flow rate \( q_o \) and the pressure drawdown:

\[
J^* = \frac{q_o}{p_{b} - P_{wof}} = \frac{7.08k_h}{B_o \mu_o} \left( \frac{k_{ro}}{p_{b} - P_{wof}} \right) \text{ for } P_{wof} \approx p_{b}
\]

Above the bubble point pressure, with immobile water and gas, oil saturation remains constant resulting in a constant productivity index, \( J^* \). If other phases are present in the wellbore, \( k_{ro} \) is reduced, and hence the productivity index is also reduced. However, with no artificial support (e.g. water or gas flooding), reservoir pressure declines fast, since the only internal energy is provided by the expansion of rock and water, which is very small.

**Inflow performance relationship**

An expression such as Eq. [1] is also called an Inflow Performance Relationship (IPR) and a graph of flow rate vs. the flowing bottomhole pressure is a
standard construction in petroleum engineering, characterizing the well performance.

**Production below the bubble point pressure**

When reservoir pressure declines below the bubble point pressure, gas bubbles will start to nucleate and coalesce. After reaching critical gas saturation, bubbles are big enough to move through the porous space, against water and oil.

For bottom-hole flows below the bubble point pressure, Vogel, in 1968, introduced an empirical relationship for \( q_o \). The relationship, normalized for the ideal absolute flow potential, is also known as the back-pressure equation:

\[
\frac{q_o}{q_o \text{max}} = 1 - 0.2\left(\frac{p_{wf}}{\bar{p}}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2
\]

where \( \bar{p} \) is the average reservoir pressure.

For the same oil-gas system in which the reservoir pressure is above the bubble point pressure, yet the flowing bottom-hole pressure could be below the bubble point pressure, the so-called Vogel flow, \( q_o \), is related to the productivity index above the bubble point pressure by:

\[
\frac{q_o}{q_o \text{max}} = 1 - 0.2\left(\frac{p_{wf}}{\bar{p}}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2
\]

for \( p_{wf} \geq p_b \Rightarrow q_v = \frac{J^* (p - p_b)}{p - p_b} = \frac{J^* (p - p_b)}{p - p_b} = \frac{p_b}{p} \cdot J^*

And the final Vogel’s relation for flow above and below bubble point is:

\[
q_o = q_b + q_o \left[ 1 - 0.2\left(\frac{p_{wf}}{\bar{p}}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2 \right] \Rightarrow q_o(t) = J^* (p - p_b) + \frac{p_b}{p} \cdot J^* \left[ 1 - 0.2\left(\frac{p_{wf}}{\bar{p}}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2 \right]
\]

A similar expression for Vogel’s back-pressure equation was suggested by Fetkovich in 1973:

\[
\frac{q_o}{q_o \text{max}} = 1 - \left(\frac{p_{mf}^2}{\bar{p}}\right)^n
\]

With the test information on two or more stabilized flow rates, the unknowns \( q_o \text{max} \) and \( n \) can be determined. With \( n = 1 \), Eq. 8 becomes:

\[
q_o(t) = J^* (p - p_b) + \frac{J^*}{2p_b} \left( p_b^2 - p_{mf}^2 \right)
\]

There is little difference between Vogel’s IPR and Fetkovich’s approximation (Fig. 4). However, Fetkovich’s correlation is said to better match field data than Vogel’s but the latter is more useful for forecasting well performance since it does not require a priori field data.

**Flow through pipes and outflow performance**

When a single-phase fluid flows through a pipe, with diameter \( D \), the pressure drop, \( dp \), over a distance \( dL \), can be obtained by solving the mechanical energy equation,

\[
dp + udg + g\frac{u^2}{2g_c} + 2f_j u^2 dL = 0
\]

where \( \rho \) is the fluid density, \( u \) is the macroscopic velocity, \( f_j \) is the Fanning friction factor, \( dW_s \) is the shaft work, \( g \) is the gravitational acceleration over \( dz \) and \( g_c \) is the gravitational conversion constant (that is the conversion factor to English engineering system of units).

Eq. [10] can be integrated to yield, assuming constant density (incompressible fluid) and no shaft work, \( dW_s = 0 \), the following:

\[
\Delta p = p_1 - p_2 = \frac{g}{g_c} \Delta z + \frac{\rho}{2g_c} \Delta u^2 + 2f_j \rho u^2 dL \frac{g_c D}{g_c D}
\]

The right hand side describes the potential energy, kinetic energy and the frictional contributions to the overall pressure drop.

Assuming a compressible Newtonian fluid, for example gas flow through pipes, the pressure drop can be calculated from

\[
p_1^2 = e^{-f_j} p_2 - 2.685 \times 10^{-3} \frac{f_j}{\gamma T} \frac{\rho u^2}{\sin \theta} \left(1 - e^{-\gamma} \right)
\]

![Fig. 4. Two-phase inflow performance relationships](image-url)
where \( s \) is given from the relation
\[
[13] \quad s = \frac{-0.0375 \gamma_k \sin \theta - L}{ZT}
\]
where \( p_1 \) is the upstream pressure and \( p_2 \) is the downstream pressure in psia; \( \theta \) is the inclination of the pipe with respect to the vertical; \( \gamma_k \) is the specific gas gravity; \( Z \) and \( T \) are the average gas deviation factor and temperature for the two pressure points; \( q_g \) is the gas rate in MSCF/D (Millions Standard Cubic Feet/Day).

Typically, multiphase flow will occur during the producing life of a well. However, even if the bottomhole flowing pressure is above the bubble point, further pressure decrease will be needed to drive the reservoir fluid to the surface. In almost all cases, gas will come out of the solution and more than one phase will coexist during the vertical lift. Free gas may help to lighten the liquid hydrostatic column up to a certain point. For high gas-oil ratios, friction losses may actually impair the flow ability. In general, multiphase fluid flow deals with the concurrent flow of oil, water and gas in vertical and inclined pipes. In more complex situations, sand and other solids (paraffines, waxes, and asphaltenes) may also compete in the multiphase vertical flow. In these cases, advanced strategies such as controlling reservoir drawdown, maintaining bottomhole and wellhead pressure above flocculation, and injecting chemicals may be necessary to assure flow.

Several correlations calculate the pressure drop in gas-liquid two-phase flow in wells. The starting point for all the methods is the mechanical energy balance [Eq. 10]. Since flow properties (density and velocities) may fluctuate appreciably along the pipe, the pressure gradient is calculated for small pipe lengths or pressure increments. The overall pressure drop is then obtained with a pressure traverse calculation, in which iteration over short length or pressure intervals may be necessary to match properties along the pipe.

The Hagedorn and Brown (1965) correlation uses the mechanical energy equation to calculate the pressure gradient, \( dp \), over a pipe length, \( dz \),
\[
[14] \quad 144 \frac{dp}{dz} = \bar{\rho} + \frac{m^2}{(7.413 \times 10^{10} D^5 \bar{\rho}) + \bar{\rho} + \frac{\Delta u_m^2}{2 g_s}}
\]
where \( \bar{\rho} \) is the in situ average density, \( f \) is the friction factor, \( m \) is the total mass flow rate (lbm/d), \( D \) is the pipe diameter (ft), \( u_m \) is the mixture velocity (ft/s), and \( dp/dz \) is in psi/ft.

Fig. 5 illustrates the two-phase vertical flow of 1,000 STB/D of 21°API crude oil, in a 2 7/8" tubing, with Gas/Liquid Ratio (GLR) of 500 and 1,000 SCF/STB, Water/Oil Ratio (WOR) of 0 and 1, using the modified Hagedorn and Brown correlation. For zero water production (WOR=0) and GLR=500 SCF/STB, the required bottomhole flowing pressure is 4,321 psia to achieve a tubing wellhead pressure of 125 psia; while for a GLR=1,000 SCF/STB, the required bottomhole flowing pressure is only 3,446 psia. Similarly, for 50% water production (WOR=1) and GLR=500 SCF/STB, the required bottomhole flowing pressure is 4,494 psia to achieve a tubing wellhead pressure of 125 psia; while for a GLR=1,000 SCF/STB, the required bottomhole flowing pressure is only 3,787 psia. As shown in Fig. 5 for the same GLR, the larger the water fraction in the water/oil mixture, the larger the pressure losses and hence the larger the bottomhole flowing pressure required to achieve a tubing wellhead pressure of 125 psia.

It is tentative to extrapolate that the larger the amount of GLR, the lower the pressure losses; which is not necessarily true. It can be shown that for WOR=1 and GLR of 2,000 SCF/STB the bottomhole flowing pressure will go down to only 3,566 psia; and for 5,000 SCF/STB the bottomhole flowing pressure will in fact deteriorate to 4,272 psia. This is due to the increase in friction losses due to slippage and high gas velocities.

**Well deliverability**

This concept combines the reservoir inflow, as exemplified by the well IPR, with the tubing

![Pressure vs. depth for different GLRs and WORs using modified Hagedorn and Brown, 1965; generated in PPS Software, 2003.](image)
performance curve, which essentially accounts for all pressure drops associated with the plumbing of the well. This combination brings the components of the petroleum production system together and can also be used for well diagnosis, analysis and identification of malfunctioning or ill-functioning parts of the system, etc. This approach has been called well performance analysis or well-known trade marked terms such as nodal analysis.

Well performance analysis is useful not just in identifying a specific solution for a given well IPR and tubing performance. It can also be used to experiment with a number of different options in IPR modification such as hydraulic fracturing, different perforation densities and even horizontal and complex wells. Also different well designs and operational conditions such as tubing diameter, wellhead pressure, chokes and artificial lift methods can be accounted for in the tubing performance curve. All options, properly examined can lead to an economic optimization: incremental costs among designs can be balanced against incremental well performance.

To calculate the well flow rate and the flowing bottom hole pressure, the well IPR (Fig. 6) is intersected with the well tubing performance curve (see again Fig. 5), leading to a solution. Given the reservoir pressure, only one IPR behaviour is possible; for a given Tubing Head Pressure (THP) of 125 psia, and a given flowing bottomhole GLR and WOR, the well deliverability is the intersection between the IPR and the respective two-phase vertical lift tubing performance curve. Consider the example in Fig. 6. The initial reservoir pressure is 11,000 psia; the above bubble-point productivity index is about 16 STB/D/psia; there is no water production, the THP is 125 psia, and the GLR is 500 SCF/STB. The 2 7/8” tubing has no artificial lift and no choke restrictions at the surface. From Fig. 6 the well’s operating point will be about 12,500 STB/D with a bottomhole flowing pressure of 10,200 psia (point 1). If the water cut increases to 50% (WOR = 1) then the same well will produce about 5,300 STB/D at 10,800 psia flowing pressure (point 2 in Fig. 6). The increase of water production in the tubing performance is detrimental. For this particular example (Fig. 6), at current well’s operating point, further availability of free gas in the wellbore, i.e. GLR going from 500 to 1,000 SCF/STB, do not improve the well deliverability in any of the cases where WOR is 0 or 1 (points 3 and 4 in Fig. 6). In fact, the well deliverability worsened in those cases where GLR was higher, for the same WOR. This is due to increased friction losses to excess gas presence in a limited-size tubing. In fact, at low well rates, i.e. fluid flow less than 3,000 STB/D at WOR = 0, or fluid flow less than 2,000 STB/D at WOR = 1, the well deliverability could be improved at a higher GLR.

In all cases, further reservoir pressure decline also would affect the well deliverability. Additionally, the well energy can be boosted by artificial methods such as electric subsensible pumps or artificial gas lift.

**Production optimization**

At a certain point in the life of a well, recovery may not satisfy physical or economic constraints and the well will be shut. At this stage, a remediation action or workover would be performed if the preliminary analysis predicts additional economic value creation. The objectives of production optimization (Fig. 7) may be to enhance reservoir inflow performance or to reduce outflow performance. The results could be more production with less pressure drawdown.

Usually, sand production, high water and low oil rates will indicate the need to revitalize the downhole well environment. Cement squeezing, fracturing and acidizing are the most common tasks...
Reservoir stimulation and/or well intervention are necessary to improve the well-reservoir connectivity (increase perforation density, reduce mechanical damage, increase fracture length) and/or boost vertical lift system performance (change tubing size, change artificial lift, remove bottlenecks).

There exist many possible solutions to mitigate the observed problems in the petroleum production system. The smarter production engineer would balance an optimum combination of analysis time effort and engineering design calculation to decide proper actions as to maintain the petroleum production system at an optimum point.

The understanding of reservoir inflow, wellbore vertical lift and surface facilities pressure constraint is necessary to optimize the field production performance. Production optimization refers to the various activities of measuring, analysing, modelling, prioritizing and implementing actions to enhance productivity of a field. Production optimization often refers to activities related to: a) well profile management (coning, fingering, well conformance management, etc.; see Chapter 4.3); b) near wellbore damage removal via acidizing or fracturing; c) near wellbore and pipeline solid deposition prevention; d) well integrity (casing and cement failure prevention and remediation); e) field and well level artificial lift optimization; f) hydrocarbon (oil and gas) and other fluids transport efficiency; g) surface facilities design and total fluid handling capacity; h) surface de-bottlenecking and continuous field-optimization.

**Continuous (real time) oil field optimization**

Opportunities for production optimization may occur at different time-scales and at different corporate decision levels. A number of new technologies introduced into oil fields over the last couple of decades now provide the technology framework for optimization of an oil field in a continuous rather than one-time fashion. Continuous Field Optimization (CFO) requires computer integration of field hardware (e.g., downhole sensors, remotely activated completions, surface facilities) for continuous decision making in a feedback fashion (data acquisition, data processing, and actuation).

One of the greatest worries of any oil/gas producing operator is how long would the well be in production without necessary intervention. Well intervention is costly, and may ruin any previous economic goal. Sometimes, it may be even more economical to abandon the well, drill a new well or just move to another area.

Smart well completions have been justified as a means to avoid rig intervention once water has appeared in a particular reservoir layer. With a simple remote actuation of downhole valves, an operator may improve the well’s life without the need of a rig intervention. However, in the onset of this technology, only high intervention cost environments have been economically viable. Although there are some low-cost solutions available in the market, new technologies are being developed to further drive down the costs.

Remotely activated (smart) completions should be used to permit reservoir data collection by performing persistent excitations, automatically regulate flow from particular zones to optimize well’s deliverability and ultimately shut a particular well’s offending layer as a result of exhausted resources.

**Planning a production optimization project**

Petroleum production engineers perform an analysis of the historical and actual production situation in order to determine the technological needs and to identify the economic benefits that would make possible an additional expenditure.
Production optimization projects cover different areas or departments in a company, which means that project coordination is needed in order to ensure the completion of the project and its benefits.

The optimization project could be affected for one or more of the following aspects:

- Business case has to match problem-specific needs and technology availability.
- Business case has to demonstrate a clear value addition to the value chain.
- The asset may have many enhancement needs which have not been prioritized.
- The budget for expenditures is limited or unknown.
- The time frame for execution is limited or unknown.
- The quality and quantity of data given is poor and limited.

It is also important to note that any production optimization project should be planned in accordance with the optimization’s objective function, which could be to reduce cost, to increase NPV (Net Present Value) or to increase production.

Objective functions may not overlap. For example, if the objective function is to reduce cost this may mean the reduction in production, which is obvious. However, reduction in production may also increase the net present value because some production may be quite unprofitable. Therefore, operators, engineers or managers should agree on the project’s objective function and avoid any operation or instruction that could be logical but against the true optimization objective function.

However, sometimes it is difficult to find opportunities for optimization due to several valid reasons, such as:

- The data are either low in quality or quantity or taken too infrequently. Conversely, sometimes the claim is that there are too many data and there are no proper systems to handle them.
- Softwares are not integrated in the system in the expected way. Common data standards or a single integrated system would be the solution, while existing models do not mimic properly the physics of the problem.
- The cost of the project would be too high.
- Organization cannot handle changes in the management so that a system becomes soon out of date.
- There is a lack of formal education in petroleum production optimization engineering and little exchange between disciplines involved.
- There is a lack of resources (time and financial) to focus on production optimization.

Production optimization projects will have the following phases: a) production data analysis, interpretation and clustering; b) opportunity identification and generation of candidate; c) rank opportunities based on some predictable success criteria; d) definition of the design components needed to optimize the implementation; e) implementation, definition and monitoring of the results; f) feedback results and ongoing monitoring of the performances to find more candidates.

**The generation of candidates for production optimization**

The generation of candidates and opportunities identification processes are directed to help petroleum production engineers to better interpret and understand the available data, and to produce and implement valuable decisions and actions. Traditional petroleum production engineering techniques (well lithology and production log analysis, interpretation of production tests, nodal analysis, material balance, reservoir simulation, etc.), in conjunction with novel oil field information technologies (data integration, downhole sensing and remote control) and numerical techniques (optimization, linear and non-linear mappings, clustering techniques, which corresponds to the use of groups of curves expressing physical properties), conform the techniques required for the generation of candidates for production optimization, also in terms of identification and design.

Some of the approaches for generating candidates for production optimization are:

**Stimulation candidate recognition for near wellbore problems.** Traditional production engineering techniques can be used to determine the economic impact that an optimum stimulation design would deliver. Opportunities should be ranked and scheduled for implementation following a sort of master plan.

**Integrated solution approach.** An integrate production optimization approach (Fig. 8) is a workflow series of processes which aim to identify, evaluate, rank and implement opportunities. Integral refers to the principle that short-term production optimization goals are in agreement with the reservoir long-term objectives.

**Advanced production optimization techniques.** Advance optimization models are created predict well performance on the basis of a series of modelled reservoir uncertainties together with well and exploitation scenarios. An optimization problem can be set-up to find the best combination of candidates that deliver the optimum value at a minimum cost.
Automated tools for candidate recognition. The use of unsupervised learning techniques, neural networks (self-organizing maps and radial basis function) and advanced statistics (partial least squares and principal component analysis) permits the extraction of key information that delivers the best candidate for production optimization. Starting from the 1990s, the number of artificial intelligence techniques has increased noticeably.

Economic evaluation. It is paramount to understand the economic impact (implementation cost vs. additional revenues) of each opportunity. It is recommended to plot the project added value vs. the cost chart, or the added value vs. the effort required, etc. Selection may involve further reservoir impact studies in order to evaluate long-term effects in the reservoir.

These techniques are not a solution by themselves and do not work alone; instead they work together, e.g. for any production enhancement proposal, it is possible that after a geologically optimized well location, an integral solution technique is executed for drainage evaluation, and then an economic analysis is completed.

Table 1 shows a number of petroleum production system problems, the data manifestations and the many possible solutions to overcome the problems.

6.2.2 Workovers to eliminate undesired water and/or gas production

Various options to reduce lifting and/or water handling costs are available for wells that produce large amounts of water or gas. These include water shut-off treatments using gelled polymers, lifting cost reduction, power options to reduce electrical costs, and separation techniques. Not all wells imply the use of any or all of these techniques, but under the right circumstances, major economic benefits can be realized.

Water and gas conformance analysis

Complex water and gas conformance problems may involve one or more of the following situations: injection induced or natural reservoir fractures;
significant permeability area and vertical variation; open hole completions.

**Water shut-off treatments using gelled polymers**

The majority of polymer treatments to control water production in producing wells are performed in fractured carbonate/dolomite formations associated with a natural water drive. Gelled polymers are created when dry polymer is mixed in water and crosslinked with a metal ion (usually chromium triacetate or aluminium citrate). Gelation is controllable, ranging from a few hours to weeks. Slower gelation time allows for more volume and deeper placement. Different polymer systems are available from different service providers.

Creating a pressure response during treatment is the single most important indicator of a potentially successful water control project. A slow, steady pressure increase over a period of time during pumping will tell the operator one of two things: the formation is reaching fill-up of polymer into the problem zone; or the reservoir temperature is causing the polymer to crosslink and build viscosity. Pressure response is a product of polymer volume, injection rate and gel strength. Altering any or all of these factors can improve the success of the treatment if reservoir resistance is not seen as the gelant is being pumped. Increasing polymer volume is typically the first step recommend if the Hall plot indicates only a slight increase of pressure near the end of the treatment. The advantage of pumping a larger volume is that greater in-depth reservoir penetration can improve the longevity and effectiveness of the treatment. The disadvantage of more volume is increased treatment costs due to longer pump times and additional chemicals.

Usually injection rates are increased at the beginning of the treatment in order to determine how easily the formation can accept a viscous fluid. Recent research and field experience have shown that higher pump rates can improve the effectiveness of treatments in carbonates that exhibit secondary permeability and porosity features. Increasing the injection rate also reduces the service company field time, which translates into a cost reduction for the operator.

Increasing gel strength or gel viscosity is the third method for achieving a pressure response. This method is typically used at the midpoint of a treatment when the Hall plot shows no increase in slope or after several treatments in a particular field indicate the need for such action. The improvement gel strength can be achieved by accelerating the crosslinking, increasing the polymer loading of the gelant, or using a higher molecular-weight polyacrylamide.

**Candidate selection**

Best candidates are shut-in wells or wells producing at or near their economic limit. These wells greatly benefit from a successful treatment and little, other than the treatment cost, is at risk if the treatment fails. Other selection criteria include significant

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**Table 1. General petroleum production system problems, manifestation and remadiation practices**

<table>
<thead>
<tr>
<th>General petroleum production system problems</th>
<th>Multiple manifestations and multiple evidence</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low productivity wells or field</td>
<td>Liquid build up in pipelines and equipment</td>
</tr>
<tr>
<td>Increasing operation and maintenance costs</td>
<td>is present</td>
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<td>Accelerated production decline</td>
<td>Well liquid level build up is present and increasing</td>
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<td>Well production is zero, or production</td>
<td>Abnormal distributed temperature profiles</td>
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<tr>
<td>losses are high</td>
<td>Permeability to oil is low or decreasing</td>
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<tr>
<td>Historic and current production is below</td>
<td>with time</td>
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<tr>
<td>target</td>
<td>Production losses and deferrement is high</td>
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<tr>
<td>Water cut is high or increasing</td>
<td>or increasing</td>
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<td>GOR is high or increasing</td>
<td>Field subsidence rate is high or increasing</td>
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<tr>
<td>Bottom hole pressure is low or decreasing</td>
<td>Equipment downtime is high or increasing</td>
</tr>
<tr>
<td>Skin effect (nearwellbore damage) is high</td>
<td>Equipment uptime is low or decreasing</td>
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<tr>
<td>or increasing</td>
<td>Safety and environment incidents are high</td>
</tr>
<tr>
<td>Pressure drop across tubing is high or</td>
<td>or increasing</td>
</tr>
<tr>
<td>increasing</td>
<td>Cement bond and other production logging</td>
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<td>Uneven fractional flow across different</td>
<td>tools</td>
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<td>zones</td>
<td>failure indications</td>
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<tr>
<td>Corrective maintenance is high or increasing</td>
<td>Resistivity profile indicating water</td>
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<tr>
<td>Pressure drop from surface pipeline is</td>
<td>presence</td>
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<tr>
<td>increasing</td>
<td>Pump or compressor vibration/lubricant oil</td>
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<td>are abnormal</td>
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<tr>
<td>Intermittent or slug flow</td>
<td>Acoustic response indicating water/gas</td>
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<td></td>
<td>sequence</td>
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</table>
Table 1 (cont’d).

<table>
<thead>
<tr>
<th>Diagnosed Problem or Cause</th>
<th>Possible Recommended Remediating Actions</th>
</tr>
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<tbody>
<tr>
<td>Low reservoir pressure support</td>
<td>Debottleneck (relax) surface pressure constraints</td>
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<td>Review/change well tubing and/or completion</td>
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<td>Implement/review secondary recovery project</td>
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<td>Implement/review artificial lift system &amp; compressor capacity</td>
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<td>(Near) wellbore collapse and instability</td>
<td>Change drawdown strategy (reduce flow)</td>
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<td>Implement fracture and pack of nearwellbore area</td>
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<td>Horizontal and multilateral wells</td>
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<td>Install gravel packs</td>
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<td>Review direction of preferential stress for drilling</td>
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<td>Water or gas breakthrough</td>
<td>Implement bacteria or gel injection to control offending zones</td>
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<td>Implement near wellbore acid stimulation</td>
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<td>Cement squeeze to shut in zones</td>
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<td>Re-perforate and change sleeve position</td>
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<td>Zonal or wellbore controlling settings (optimize total flow)</td>
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<td>Implement/review enhanced oil recovery</td>
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<td>Implement fracture and pack of nearwellbore area</td>
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<td>Crossflow</td>
<td>Zonal or wellbore control settings (optimize total flow)</td>
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<td>Re-perforate and change sleeve position</td>
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<td>Change drawdown strategy (reduce flow)</td>
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<td>Horizontal and multilateral wells</td>
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<td>Surface Pipeline and valves failures</td>
<td>Repair/change pipeline and valves</td>
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<td>Install filters and monitoring equipment</td>
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<td>Change/review pipeline facilities design practices</td>
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<td>Casing, cement, tubing, rod and motors failures</td>
<td>Cement squeeze to shut in zones</td>
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<td>Reparce casing, tubing, rod and motors are required</td>
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<td>Change/review casing, tubing, rod and motors design practices &amp; limits</td>
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<td>Surface bottlenecks</td>
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<td>Implement/review periodic steady state surface optimization</td>
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<td>Change/review surface facilities design practices</td>
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remaining mobile oil in place, high water-oil ratio, high producing fluid level, high initial productivity, wells associated with active natural water drive, structural position and high permeability contrast between oil and water-saturated rock (i.e., vuggy and/or fractured reservoirs). Successful treatments have been conducted in both cased and open hole completions.

**Treatment sizing**

Only empirical methods exist at this time for sizing treatments. Experience in a particular formation is
most beneficial. However, in many instances larger volume treatments appear to decrease water production for longer periods of time and recover more incremental oil. Some rules of thumb include two times the well’s daily production rate as the minimum polymer volume or using the daily production capacity of the well at maximum drawdown (i.e., what the well would be capable of producing if it were pumped off) as the treatment volume. In lower fluid level wells the daily production rate is sometimes used as the minimum polymer volume.

**Preparation prior to pumping**

The wellbore needs to be clean, acidized if necessary (typically 350-500 gal 15% acid, pump away with water). A maximum treating pressure must be established; a step rate test to determine parting pressure needs to be run if necessary. An acceptable source of water to blend and pump the treatment must be selected. The water’s compatibility to form the desired gels needs to be tested. A polymer-compatible biocide for the mix water (typically 5-10 gallons per 500 barrels of mix water) must be selected. Tubing and packer above the zone to be treated need to be set.

**Placing treatment**

Stages of increasing polymer concentration must be used. It is necessary to inject treatment at a rate similar to the normal producing rate. Treatment pressure must be kept below reservoir parting/fracture pressure. Changing conditions during treatment may warrant design changes during pumping. The treatment should be over-displaced with water or oil. In some instances, a rapid pressure response early in the treatment is a sign that the treatment may not be successful.

**Water shut-off using cement**

When a producing zone has been fully (or almost) watered out, one recommended technique is to force cement slurry through the perforations to shut-off that offending layer. Alternatively, cementing operations may be undertaken to set a plug in an existing well from which to plug a well horizon so that it may be abandoned due to high water-cut or excessive gas production.

### 6.2.3 Reservoir stimulation: matrix acidizing and hydraulic fracturing

The general common objective of well stimulation via matrix acidizing or hydraulic fracturing is to reduce pressure restrictions around wellbore and the increase flow rate.

**Matrix acidizing**

The purpose of matrix acidizing is to dissolve rock material and remove drilling mud and clay creating new flow paths and increasing permeability in near wellbore area. Acid is used to remove damage from carbonate and sandstone formations and to stimulate production and injectivity in carbonates. Acid is used for both matrix and fracture treatments in carbonates. Matrix acid candidates have permeability greater than 10 md in oil wells and 1 md in gas wells. Acid frac candidates have permeabilities less than 10 md in oil wells and 1 md in gas wells. Matrix acidizing is performed below the fracturing rate and pressure of the formation, where acid travels through existing pores and natural fractures. Fracture acidizing is performed above the fracturing rate and pressure of the formation, where the rock is cracked and an etched fracture is created.

Matrix acid treatments are commonly used to increase injectivity in disposal and injection wells. If acidizing injection and disposal wells is needed on a regular basis to maintain injection rates, water quality should be examined.

Carbonate rocks, mainly conformed by limestone (CaCO₃) and dolomite (CaMg(CO₃)₂), rapidly dissolve in HCl and create reaction products, calcium chloride (CaCl₂), magnesium chloride (MgCl₂), carbon dioxide (CO₂) and water (H₂O), that occur under the following balanced equations:

\[
\text{Calcite} \Rightarrow \text{CaCO}_3 + 2\text{HCl} \rightarrow \text{CaCl}_2 + \text{CO}_2 + \text{H}_2\text{O}
\]
\[
\text{Dolomite} \Rightarrow \text{CaMg(CO}_3)_2 + 4\text{HCl} \rightarrow \text{CaCl}_2 + \text{MgCl}_2 + 2\text{CO}_2 + 2\text{H}_2\text{O}
\]

In carbonates, the rate of dissolution is limited mainly by the speed with which acid can be delivered to the rock surface. This results in rapid generation of irregularly shaped channels, called **wormholes**. The acid increases production by creating bypasses around the damage rather than directly removing it.

Silicate matrix acidizing is different from carbonates. Sandstone, mainly conformed by silicon dioxide (SiO₂), reacts with hydrofluoric acid (HF) to produce silicon tetrafluoride (SiF₄). As a secondary reaction, silicon tetrafluoride (SiF₄) will react with more hydrofluoric acid (HF) to produce silicon hexafluoride (SiF₆²⁻). Hydrochloric acid does not react with silicate materials. SiO₂ and HF reactions occur under the following balanced equation:

\[
4\text{HF} + \text{SiO}_2 \rightarrow \text{SiF}_4 + 2\text{H}_2\text{O}
\]
\[
\text{SiF}_4 + 2\text{F}^- \rightarrow \text{SiF}_6^{2-}
\]
By comparison, the reaction rate between HF and sandstones is much slower than HCl. Mud acidizing seeks to unblock existing pathways for production by dissolving wellbore damage and minerals filling the interstitial pore space, rather than creating new pathways. The HF reacts mainly with the associated minerals of sandstones, rather than the quartz. The acid reactions caused by the associated minerals (clays, feldspars and micas) can create precipitants that can cause plugging. Much of the sandstone acid’s purpose is to prevent this possibility. A considerable improvement in the success rate of sandstone matrix acidizing was achieved by monitoring, in real time on the field, the evolution of skin effect and damage removal. Such monitoring evaluates whether the fluids are adequate with regards to their composition and volume. It also assesses the required modification for the treatment or for future improvements in other treatments.

Another challenge that must be faced in either lithology is how to direct the acid flow. As acid is pumped, it flows preferentially along the most permeable path into the formation. The acid opens these paths up even more, and less permeable, damage zones are almost guaranteed not to receive adequate treatment. A technique to divert the treatment fluid towards damage formations or damage perforations is therefore mandatory.

There is a variety of diversion techniques. Treatment fluid can be directed exclusively towards a low permeability zone using drill-pipe or coiled tubing conveyed tools, equipped with mechanical packers. The diversion of treatment fluids can also be achieved by bullheading acid at maximum injection rate below the fracture pressure. This maximum injection rate maintains a sustained differential pressure in the near wellbore area to be treated. Alternatively, flow can be blocked at individual perforations.

In carbonates, bridging agents such as benzoic acid particles or salt can be used to create a filter cake inside wormholes, encouraging the acid to go elsewhere. In sandstones, microscopic agents such as oil-soluble resins can create a filter cake on the sand face. Chemical diverters such as viscous gels and foams created with nitrogen are used to block high-permeability pathways.

The requirements on any diverting agent are stringent. The agent must have limited solubility in the carrying fluid, so it reaches the bottom of the hole intact. It must not react adversely with formation fluids; it must divert the acid. Finally, it must clean up rapidly so as not to impede later production. Ball sealers drop in the rat hole as soon as injection halts or, if they are of the buoyant variety, they are caught in ball catchers at the surface. Benzoic acid particles dissolve in hydrocarbons. Oil-soluble resins are expelled or dissolved during the ensuing hydrocarbon production. Gels and foams break down with time.

**Hydraulic fracturing**

Hydraulic fracturing is used to create high permeability flow conduit in tight rocks, increasing the area of flow to wellbore. It is also used in highly permeable rocks as sand control, liquid dropout prevention or turbulent flow control technique by decreasing pressure drop around the wellbore. The initiation of a hydraulic fracture in a well is the tensile failure, or breakdown, of the surrounding rock caused by the injection of fluid (Economides et al., 1994, 1998; Dusterhoft and Chapman, 1994; Economides and Nolte, 2000; Fan and Economides, 1995; Mukherjee, 1999). Fracture propagation from the well into the reservoir is extended as fluid at high rate continues to be injected. The pressure needed to initiate the fracture is often considerably greater than the pressure required to propagate the fracture. Commonly, at an appropriate instant during injection, proppant is added to the fracturing fluid to keep the fracture open. Thus, a conductive pathway is created for fluid flow from the reservoir to the wellbore.

In the past, hydraulic fracturing has been used almost entirely to stimulate the production or injection of wells in low-permeability reservoirs (Economides et al., 1994, 1998; Mukherjee, 1999; Economides and Nolte, 2000). Such a hydraulic fracture invariably results in a high-conductivity pathway, and thus, for low-permeability reservoirs the intention has always been to generate a long fracture allowing considerable penetration of the reservoir by such a high-conductivity path. This goal is conveniently accomplished in unrestricted fracturing. However, in high-permeability reservoirs, the incremental conductivity obtained under normal circumstances from a traditional fracture treatment would be very small, leading to a low-conductivity fracture. Low conductivity would also lead to a large pressure drop along the fracture during production. This would mean wasteful over-treatment because much of the fracture length would not contribute effectively to well production.
Some readers may find part of the logic of the paragraph above difficult to comprehend. It should be stressed that conductivity is a measurement of the contrast between the ease with which fluids flow in the created fracture compared to the alternative, i.e., no fracture. In low-permeability formations even a bad treatment can produce a high-conductivity fracture. Narrow and lengthy fractures are needed. Frequently, this notion escapes even practitioners in the field. It is not a great accomplishment to pump a large amount of proppant and pack a fracture in a low-permeability formation. Pumping very small proppant slurry concentrations for very long periods of time is often what is guaranteed.

In contrast, in higher-permeability reservoirs, the resulting fracture conductivity is of paramount importance while the fracture length is secondary. This physical demand in the fracturing of high-permeability reservoirs was aided greatly by the introduction of the Tip-Screen-Out technique (TSO; Smith et al., 1987). This is the arrest of the lateral growth of the fracture, which is subsequently inflated. The result is a relatively short, large-width fracture with much higher fracture conductivity compared to what unrestricted fracturing could yield. Furthermore, a small fracture length limits the fracture fluid leak-off into the formation (which is severe in high-permeability reservoirs) and hence, contributes to the success of the treatment. Thus, in the last few years, high-permeability reservoirs have also become attractive candidates for hydraulic fracturing.

Objectives of high-permeability fracturing

The general objective is to stimulate the production or injection rate of a well. Beyond the obvious motivation, there are several other objectives in the fracturing of a high-permeability formation, described below.

Bypassing formation damage. A fracture that penetrates beyond the near-wellbore damage region effectively bypasses and nullifies the effects of this damage zone. These effects, left unchallenged, would result in impaired productivity and invariably unwanted larger pressure drawdown. Often, matrix simulation to remove the near-wellbore damage is either partially effective or totally ineffective.

Reduction of near-wellbore drawdown during production. Pressure drawdown, which is equal to the reservoir pressure minus the flowing bottomhole pressure, is the sole driving force for flow from the reservoir to the wellbore. As drawdown increases it may affect the formation stability. Formation instability may cause fines and sand to migrate into the wellbore region. A short and wide fracture can overcome this problem by reducing pressure losses and velocities in the reservoir sand near the wellbore.

Improving communication between reservoir layers and the wellbore. In multiple laminated sand/shale sequences, the thin laminated sand layer may not communicate efficiently with the wellbore until a fracture is performed to provide a continuous, vertically penetrating, connection to the perforations.

Reducing the effect of non-Darcy flow in most dry gas and/or gas condensate reservoirs. Generally, for reservoir permeabilities below 5 md there is little effect from non-Darcy flow. In higher-permeability reservoirs, the non-Darcy term becomes increasingly important and could significantly reduce the well production rate. A hydraulic fracture provides further conductivity and the flow velocities from the reservoir can be reduced enough so that non-Darcy effects are either eliminated or markedly reduced (Settari et al., 1998).

Candidate well selection for high-permeability fracturing. To determine which well is suitable for high-permeability fracturing and, of even greater importance, the size and type of fracture treatment, candidates are classified into two major categories depending on what is expected from the well. For production enhancement these are:

- Formations where matrix acidizing is not possible due to mineralogy or because the penetration of damage is too deep or too severe to be removed by matrix stimulation.
- Multiple pay zones in laminated sand/shale sequences, in which the laminated layers could not communicate with the wellbore unless a fracture provides the connection.
- Gas wells in high-permeability reservoirs in which production is impeded because of non-Darcy flow. A fracture can greatly reduce the non-Darcy effects. According to Settari et al. (1998), for any reservoir permeability, as the reservoir pressure increases, the fracture becomes less effective in reducing reservoir turbulence and a longer fracture is needed.

For near-wellbore drawdown related problems the following are suitable:

- Poorly consolidated formations in which fracturing may act as a substitute to gravel pack without the associated plugging,
which almost always appears in gravel packs resulting in large positive skins. The main mechanism that favours high-permeability fracturing over gravel packs in poorly consolidated formations is the reduction in the fluid flux at a desired flow rate because of the substantial increase in the area of contact with the reservoir. This increase in area prevents the de-consolidation of sand and its migration towards the well. All wells that are candidates for gravel packing, especially wells in which gravel packs might reduce the near wellbore permeability, are generally even better candidates for high-permeability fracturing.  

- Low-bottomhole-pressure wells in which formation could not afford the required drawdown for satisfactory radial flow production.

**Procedure for candidate recognition for high-permeability fracturing**

It is, first of all, important to determine and confirm that the well is under-performing. Well production rate alone, which may be below one’s fond expectations, may not mean that the well is a candidate for stimulation. This notion implies that the production engineer must know the well, the actual geology, the reservoir pressure and its depletion, the real drainage and, of course, the all important reservoir permeability.

Furthermore, ignorance of the reservoir permeability and the associated well skin effect may lead to substantial errors, not only in selecting the appropriate stimulation treatment (i.e. matrix stimulation or hydraulic fracturing). As it will also be shown later in this chapter the value of the reservoir permeability is crucial to the sizing of the hydraulic fracture. It is not enough just to decide that fracturing is appropriate. A pressure transient test, to delineate between the controlling influences on production (permeability vs. skin) is strongly recommended, especially in high-permeability reservoirs.

A large pre-treatment skin effect may not necessarily mean damage, let alone acid-removable damage. Other factors may provide large skin effects such as phase behaviour and turbulence. The latter is particularly important in high-permeability gas or two-phase wells. It is essential for well performance analysis and identification of production impediments to be thorough both for the design and the subsequent evaluation phase of the stimulation treatment.

The reservoir rock and fluid chemistry must therefore be well understood especially considering the potential unpleasant side effects of matrix stimulation treatments. In the past, when only low-permeability fracturing was possible, there were no choices: permeability less than 1 md meant fracturing; permeability substantially large meant matrix stimulation. If undesirable side effects were unavoidable, the engineer had only one choice: perform the treatment and take the penalty or not do it at all. Today, with high-permeability fracturing, bypassing damage is a very legitimate alternative in any-permeability reservoir. Intelligent and economic-motivated choices are now possible.

Finally, there is no question that reservoirs with sand production are particularly attractive for high-permeability fracturing. In this respect the verdict is unambiguous. In almost all cases, wells with sand production problems are far more likely to benefit from fracturing than any other sand exclusion technique such as gravel packing.

**Key issues in high-permeability fracturing**

Taken as a continuum, high-permeability fracturing does not differ from low-permeability fracturing. The optimum dimensionless fracture conductivity that can be achieved is 1.6 for any proppant volume in an infinite acting reservoir (Prats, 1961). The dimensionless fracture conductivity, introduced by Cinco-Ley et al. (1978) is:

\[
C_{fD} = \frac{k_{fW}}{k x_f}
\]

where \(C_{fD}\) is dimensionless fracture conductivity, \(k_f\) (mD) is the proppant pack permeability, \(w\) (ft) is the average fracture width, \(k\) (mD) is the formation permeability and \(x_f\) (ft) is the fracture half length. The fracture conductivity and the fracture length are combined in the estimation of a skin effect, \(s_f\), which acts as an ‘accounting’ procedure for the stimulation effects of a hydraulic fracture. Added to the dimensionless pressure term describing the reservoir behaviour, this skin effect functions at radial and pseudo-radial flow exactly as any other skin effect.

In high-permeability fracturing the demand is for a much higher fracture conductivity compared to what would be obtained from unrestricted fracture propagation; the fracture length is of secondary importance. This higher-conductivity fracture can be achieved with a larger fracture.
width (versus an acceptable much narrower width for low-permeability fracturing), large proppant pack permeability and short fracture length (versus a required long fracture length in low-permeability reservoirs). The need for high-proppant concentration in the fracture sometimes results in the use of high-proppant-slurry concentration. Thus, high-permeability fracturing needs more planning, better understanding of fluid and proppant rheology and careful placement of the proppant pack compared to low permeability reservoirs.

To maximize the proppant concentration inside the fracture and to achieve higher conductivity, the TSO technique is employed. In a TSO, the lateral fracture propagation is arrested (a complete screen out should be achieved), after which continued pumping will inflate the width of the fracture and will result in a short but highly conductive fracture. To properly execute a TSO, a pre-treatment test or ‘minifrac’ should give accurate values for fracture closure pressure, fracture closure time, and fluid properties.

The execution of a fracture treatment in a high-permeability reservoir is impeded severely by fluid leak-off. Filter cake-building fracturing fluids (such as crosslinked polymers) are used to reduce the invasion of polymer into the reservoir, normal to the direction of fracture propagation. Otherwise, if the invasion is not controlled, severe permeability damage could occur in the reservoir.

Cinco-Ley et al. (1978) and Cinco-Ley and Samaniego (1981) provided the understanding of the factors affecting the performance of finite-conductivity fractures and identified the types of damage impeding their performance.

Reduction to the proppant pack permeability. This kind of damage affects the proppant pack inside the fracture and is a manifestation of proppant crushing and, especially, of unbroken fracturing fluid polymer. These phenomena have particularly detrimental impacts on the fracture conductivity and should be avoided or minimized. The problem with proppant crushing can be reduced considerably by selecting appropriate-strength proppants. In high-permeability fracturing ‘cutting corners’ on proppant quality should be avoided, practically at any cost. In fact, in view of the relatively small volumes, required in high-permeability fracturing, moving towards the highest quality and strength proppants can be readily justified. The potential incremental benefits are such that any savings in proppant costs can be over-shadowed by even minute reductions in the proppant pack permeability. To minimize polymer-related problems, extensive research has been conducted in the last several years on breaker technology (in which chemicals are used to break the three-dimensional structure of the polymers). Work has also been done for the use of appropriate chemical agents and the method of their delivery.

Choke damage. This refers to the near-well damage inside the fracture. It can be depicted by a skin effect. This kind of damage results either from fines migration during production and their accumulation near the well (within the fracture) or over-displacement at the end of the treatment (this is a fatal error if it happens) or inadequate perforations connected with the fracture. It is possible to calculate the skin from the choked damaged fracture by assuming steady state flow in the damaged zone (Cinco-Ley and Samaniego, 1981):}

\[
s_{fs} = \frac{\pi b_f k_{jfs}}{b_j k_p}
\]

where \(x_f\), \(b_f\), \(k_{jfs}\) are the damaged fracture length (ft), width of damaged fracture (ft) and damaged fracture permeability (mD), respectively. Fig. 9 is a schematic diagram of choke damage.

Fracture face damage. This kind of damage, caused conventionally by fracturing fluid leak-off, results in permeability impairment outside the fracture, normal to the fracture face. Again Cinco-Ley and Samaniego (1981) provided a means to account for this damage by virtue of a skin effect, defined by:

\[
s_{fs} = \frac{\pi b_f}{2\gamma} \left( \frac{k}{k_x} - 1 \right)
\]

where \(b_f\) (ft) is the penetration of damage normal to the fracture face and \(k_x\) (mD) is the damaged permeability inside this zone. Fig. 10 is a schematic diagram for this damage.

Combined effects. Mathur et al. (1995) proposed a means to account for composite damage that can be quantified by a skin effect expression. This composite skin, or damage skin \(s_d\) may be represented by:

\[
s_d = \frac{\pi}{2} \left[ \frac{b_j k_{jfs}}{b_j k_s + |x_f - b_j| k_2} \frac{b_j - b_{jfs}}{b_j + |x_f - b_j| k_R} \right]
\]

Fig. 11 is a schematic diagram of the composite damages accounted for in \(s_d\).

The damage skin, given by Eq. [18] can be added directly to the estimated fracture equivalent skin effect \(s_f\) (Cinco-Ley et al., 1978) to obtain the total skin:

\[
s = s_d + s_f\]

where \(s_f\) can be determined from Fig. 12.
It is relatively easy to see that for a long fracture (>100 ft), the fracture face damage has little impact on well performance. This is not true for short fractures with significant damage penetration and small fracture conductivity. For a shorter fracture, such as the ones performed in high-permeability reservoirs, it would be necessary to consider fracture face damage impairment along with the all-important high fracture conductivity.

Hunt et al. (1994) have suggested that the initial productivity impairment because of fracture face damage may diminish over time for a suitably designed treatment. Aggour and Economides (1999) concluded that the penetration of damage normal to the fracture face is more important than the degree of damage. If the penetration of damage is minimized, even 99% damage to the reservoir permeability should still result in a negative skin. This is an important conclusion suggesting that even though the performance of high permeability fractures is expected to improve with time as cleanup of the fracture occurs, the appropriate choice and engineering of fracturing fluid can reduce or even eliminate the time of initial loss production significantly.

Aggour and Economides (1999) further proposed the use of high polymer loads of crosslinked fracturing fluids to minimize penetration of damage. To complete the fracturing fluid design there is a crucial need for good breakers and filter cake building additives. This type of fracturing fluid can minimize the spurt loss and leak-off. Thus, in high-permeability fracturing, while creating a highly conductive fracture should be the primary concern, the same treatment must be engineered to prevent fracture face damage, a potential highly detrimental event.

**Causes of underperformance of high-permeability fracturing**

Additional causes of underperformance of high-permeability fracturing include:

a) the failure to attain the designed geometry, such as unconfined height growth and failure of TSO to arrest lateral growth; b) inappropriate perforations that might lead to the creation of multiple and tortuous fractures instead of the...
designed vertical fracture; c) asymmetric fracture extension, which is more common in depleted reservoirs; d) insufficient fracture coverage in multilayered reservoirs that can lead to communication breakdown between the formation and wellbore. Furthermore, an emerging understanding for well under-performance is one that can be attributed to the formation of liquid condensate in gas-condensate reservoirs.

**Gas condensate reservoirs**

Gas condensate reservoirs frequently experience a phenomenon that has a similar effect as fracture-face damage in high-permeability reservoirs. The pressure gradient that is created normal to the fracture causes liquid condensate to form, creating a gradient into the reservoir. This liquid condensate has a direct impact on the relative permeability-to-gas, which is reduced. The phenomenon is tied to the phase behaviour of the fluid, i.e., the dew point pressure and the penetration of liquid condensate, which depends on the pressure drawdown imposed on the well. This entire process causes an apparent damage that affects the performance of all fractured gas condensate wells irrespective of the reservoir permeability although it would be particularly detrimental in high-permeability reservoirs. The fractures are much shorter and the penetration of the pressure gradient normal to the fracture is much longer.

The pressure and flow rate behaviour of a gas condensate is distinctly different from the behaviour of a two-phase reservoir. In a two-phase oil and gas reservoir the two-phase envelope (see Chapter 4.2) describes a region bracketed between the bubble point pressure and the flowing bottomhole pressure. Such behaviour applies to the left (i.e. at lower temperature) of the pseudo-critical point on the phase diagram. Starting at the right of the pseudo-critical point, the locus of the dew point pressures curves until it reaches the cricondentherm point (maximum temperature point). Between the pseudo-critical and the cricondentherm points, as the pressure declines from the dew point pressure (at constant temperature) liquid emerges. The amount of liquid increases as the pressure in the reservoir decreases until a certain value at which further reduction of the pressure causes the liquid to re-vaporize. This region is called the retrograde condensation zone and reservoirs experiencing this phenomenon are known as gas condensate reservoirs.

The production rate of gas condensate reservoirs is not affected only by the pressure gradient but is a much more complex function of also the actual value of the flowing bottomhole pressure since the latter dictates the amount and distribution of liquid condensate accumulation near the wellbore. One simple way to prevent the formation of condensate is to maintain the flowing bottomhole pressure to be above the dew point. However, in almost all cases the resulting pressure gradient may not be sufficient enough for an economically attractive production rate. This leads to either an optimization balancing of drawdown vs. relative permeability impairment or, more appropriately, to the hydraulic fracturing of gas condensate wells.

Gas condensate reservoirs under radial flow can be divided into three regions based on the type of flow (Settari et al., 1996). The first region is the farthest away from the wellbore, where the pressure is higher than the dew point. Only gas is present and is affected by Darcy radial flow with a controlling permeability, the effective permeability to gas. The second region is characterized by pressure slightly below the dew point. The condensate liquid forms but the liquid saturation is low. The flow is still Darcy flow. The flowing fluid is primarily gas in this region. However, the emergence of condensate causes a reduction of the relative permeability to gas. The third region is the near wellbore area. It has the lowest pressure and the highest velocity. As the fluid converges to the wellbore, the cross-sectional area of flow is reduced substantially and the flow becomes non-Darcy. At the boundary of the first region and the second region, the pressure is equal to the dew point. From the boundary inwards (towards the wellbore and including the third region), the condensate film or ring around the fracture acts as a fracture face skin.

Similar two-phase regions appear in the case of a hydraulically fractured well except that the distribution of the liquid condensate normal to the fracture (the length of damage penetration can be tens of feet for high-permeability reservoirs) can reduce the amount of production significantly. Thus, optimization is necessary because of the need to adjust the fracture geometry.

Wang et al. (2000) conducted a study of production impairment and presented a purpose-built...
design for hydraulic fractures in gas condensate reservoirs. The study demonstrated that the required fracture length was the essential element to adjust in order to offset the problems associated with the emergence of liquid condensate. Invariably, much longer fracture lengths (and therefore much bigger treatments) would be required to provide the expected productivity index from an optimization scheme that ignored the effects of condensate.

Non-Darcy effect

In high-permeability reservoirs, non-Darcy effects can significantly reduce well production rates. Non-Darcy flow hampers the well production in fractured gas reservoirs in at least two ways: the apparent permeability of the formation may be reduced (Wattenburger and Ramey, 1969); the non-Darcy flow may reduce the conductivity of the fracture (Guppy et al., 1982).

Screenless and rigless completions

Substantial effort has been expended to reduce treatment costs and to simplify treatment execution. One important item is the removal or simplification of gravel-pack screens and tools that are still used in high permeability fracturing completions. Kirby et al. (1995) reported that several screenless high permeability-fracturing treatments have been completed with considerable success. The executions eliminated the screen completely and used conventional fracturing method with a modification: the final proppant stage was tailed in with resin coated sand to control proppant flowback. However, further research is being conducted to ensure the resin-coated proppant is placed as needed to prevent proppant flowback and thus, ensure a high conductivity connection between the fracture and the wellbore.

Screenless, high permeability fracturing has the potential to allow the development of multiple-zone high permeability fracturing completions. Hailey et al. (2000), proposed a new screenless single-trip multizone sand control tool system. This system enhances the benefit of screenless high permeability fracturing by reducing the time required to complete multiple producing intervals in unconsolidated sand formations during one single trip into the well. The approach incorporates the previously used pumping process of simultaneous fracturing with proppant slurry and chemical consolidation of that proppant. Resin coated proppant is used during slurry pumping to provide sand control and flowback control while leaving the casing across the interval clear (except for multiple isolation packers that can be used for production management during the life of the well in order to control production from the various zone for optimum recovery and maximum production).

The primary cost cutback from utilizing these approaches is the reduction of rig time associated with tripping drill pipe in and out of the hole, as it is necessary for conventional completion of multiple fracturing treatments. As the number of treatments completed in a single trip increases, the cost per treatment decreases. This type of completion provides opportunity for small and economically marginal reservoirs to be completed along with more valuable reservoirs in one process to make a total project achieve the required profitability.

Screenless high permeability fracturing also allows through-tubing completions. The major benefit of such completions is that they can be done without a rig on location. New high permeability fracturing equipments are also emerging to enable rigless coiled tubing completions in wells that are completed with gravel-pack screens (Ebinger, 1996). This advancement could cut the rig costs and inefficiencies associated with rig timing.

6.2.4 Sand control

One of the major issues associated with oil and gas wells is the production of formation particles, often referred to (and at times incorrectly) as sand. If the problem is not addressed properly, it can cause a wide range of costly and potentially hazardous problems. Sand production accumulating in the tubulars will reduce oil and/or gas production from the well. If the well has enough energy to carry the sand to the surface, it can cause severe pipe erosion. Once on the surface, it can play havoc on the surface equipment. Premature failure of downhole equipment, such as electric submersible pumps, can prove very costly and failure of subsurface safety valves can be extremely dangerous. In addition to the problems it can cause on the mechanical aspects of the well, sand production can also cause significant formation damage, which can reduce well performance dramatically. It is important that the potential of sand production is identified
before completing the well and steps are taken to prevent it. If sand control measures are not taken early enough, serious formation damage can take place, which will limit the amount of options and diminish the productivity of the well.

**Mechanics of sand production**

To design the correct sand control method, first the mechanics of sand production need to be understood, as described below.

**Grain-by-grain movement.** Perhaps the cause of most formation failures; sand moves away from the formation face. If sand control measures are not taken in time, the options of sand control become limited.

**Movement of small masses.** Formation rock can break away and cause rapid failure. The wellbore gets sanded and once the perforations in the casing are covered it will cease to produce.

**Massive fluidization.** Massive amounts of sand can cause erosion or prevent production. Also, disposal of massive amounts of sand can become a problem.

**Methods for sand production control**

There are five methods for sand production control: production restriction, mechanical methods, chemical methods, combination methods and high-permeability fracturing.

**Production restriction.** Lowering the production rate reduces the fluid velocity in the formation, which can reduce sand production. The lower rate however might not be always economical and not work. Horizontal wells which can produce at the same or high rate as vertical wells, at a lower drawdown pressure and a lower fluid velocity might be an option.

**Mechanical methods.** Perhaps the most widely used methods, they are very heterogeneous but always include some kind of a device installed to filter and prevent the formation sand from entering the wellbore. These devices can be wire-wrapped screens, slotted liners, prepacked screens and metal filters, usually used with gravel packs. Wire-wrapped screens and slotted liners filter out formation sand and retain graded sand or propping materials, which are placed against the formation to support it. Gravel packs are mechanical bridging systems which can be achieved by placing large amounts of proppant (sized) against the formation face and held in place by a screen or slotted liner.

**Chemical methods.** These methods are achieved by injecting plastics or resins into the formation. The objective is to provide a grain-to-grain cementation (sand consolidation) without loosing permeability.

**Combination methods.** These methods combine mechanical sand control methods and chemical consolidation. Gravel pack sand or proppant material (mechanical filter) is coated with resin and when cured it bonds the sand together and holds it in place (chemical consolidation).

**Methods of high-permeability fracturing.** Perhaps the most effective technique for sand production control, while it also provides well stimulation in high-permeability fracturing. The control is achieved by a major reduction in the flux (velocity) of the fluid. Because the presence of a fracture provides a very large cross-sectional area of flow, compared to radial flow, the fluid velocity is reduced dramatically for a given volumetric flow rate. **Particle deconsolidation** is an erosion process and the reduction in the flux reduces the particle migration considerably. Also, the presence of a successful fracture precludes any radial flow into the well and an added benefit is that such well completion does not require screens, if the fracture proppant is consolidated properly.

**Gravel and screen design**

For the gravel pack design to work properly and to provide for the optimum well performance, the gravel must be large enough to allow formation fines and clay particles to flow through, so it does not plug up the gravel pack and, at the same time, it should be small enough to filter out formation sand. The screen must be able to retain all the gravel in place. The first step to sizing the gravel is to obtain a representative sample of formation material and to determine the particle size distribution in the formation by performing a series of sieve analysis. Once this is done, correlations have been developed in selecting the right gravel size.

There is a large variety of liners and screens, which can be used to retain the gravel pack, and its selection can affect how well the gravel is packed, the flow capacity and the life of the gravel pack. At the economic end of the scale is the **slotted liner**. Slots are milled longitudinally on oilfield pipe; the size of slots can vary to match the needs. This liner provides good strength and it is best suited for water wells. Single or dual wrapped screens, are made with slotted or drilled oilfield pipe, wrapped with keystone shaped stainless or corrosion resistant wire. The screen is spaced-out from the
pipe to allow for maximum flow through the screen. This type of screen can also be prepacked with gravel. Another type is the *casing-external prepacked gravel-pack screen*. Best suited for horizontal wells, this is a wire wrapped screen with two concentric pipes. The inner diameter is the same like a small-diameter slotted liner and the outer pipe is a larger slotted liner. In between they pack it with resin-coated gravel. The wire wrapping is to prevent the gravel to leak through. It is usually prepacked with resin-coated gravel. There is also the low profile screen, the sintered metal screen, the *woven metal-wrapped*, the *auger-head screen*, while new designs keep being developed.

Once the screen is selected and the gravel pack has been designed, the screen has to be placed in the well and packed with gravel. For this, special fluids are required which are able to transport the gravel, separate from the gravel to allow for a good pack, and be produced out of the well with little or no damage to the formation.

### 6.2.5 Perforating

The process of completing a well includes casing and cementing the wellbore. Steel casing is installed in the well and is cemented in place, totally isolating the reservoir from the wellbore. Before any oil and/or gas can be produced or injected into the reservoir, communication between the wellbore and the reservoir has to be re-established. This is done by ‘perforating’ or drilling the casing at the objective horizon. The penetration of these perforations must extend beyond the cement and into the formation.

One of the oldest methods of perforating is the bullet gun kind. It was patented in 1926 and until the 1950s it was the most widely used method. A short barrel (2" or less) is loaded with propellant and a bullet. Several of these barrels are arranged on a steel carrier called the gun, which is lowered into the well at the desired horizon and the propellant is ignited by an electric signal sent by wire. The bullet is accelerated and shot into the casing, perforating both the casing and the cement into the formation. The bullet type perforator is suitable for wells in softer formations, but its performance diminishes in harder formations.

A second method of perforating is through high-pressure water or sand laden slurry jets. Water or slurry is pumped down the tubing. A deflector and nozzle at the end of the tubing directs the fluid stream, which impinges directly into the casing making holes, slits, or even cutting the casing completely. A variation of this method has a flexible extending lance at the end of the tubing, which can jet its way into the formation, creating clean tunnels with very little or no damage at all. The drawback is that only one perforation at a time can be made, a time consuming and expensive.

Jet perforating uses metal lined shaped charges and is the widest method of perforating today. It is based on armour piercing technology developed in the Second World War. The design of the shaped charge is simple (Fig. 13). It consists of the case, a metal liner usually made of copper in a conical shape, high explosives and the detonator. When the high explosives are detonated, the pressure, which is in the range of 15,000,000 to 30,000,000 psi, is focused on a small area, causing the copper liner to become a jet, travelling at a speed of 13,000 to 26,000 ft/s. This high-pressure copper jet creates a channel through the casing, the cement and into the formation, just like a jet of water can create a hole in gelatin. Typically, this channel has a diameter of 0.25 to 0.4" and length of 6 to 12", though perforations with larger diameter and deeper penetration are currently offered. Shaped charges are arranged on a steel carrier called a *train*, or a perforating gun as shown on Fig. 14. The number of shaped charges per unit length is called the perforation density and is typically measured in shots/ft. The angle between adjacent charges is called the phase angle. The train, or perforating gun, can be conveyed downhole with production tubing, coiled tubing, slick line and electric line. The charges can be detonated with either mechanical or electrical detonators.

At the moment of perforation, crushed rock and debris can enter the perforation tunnel, thus impairing its ability to allow fluid to flow...
or even totally plugging the perforation off. One way that has been proven very effective in minimizing damage to perforations is underbalanced perforating. Underbalanced perforating is defined when the pressure in the wellbore is lower than the pressure in the reservoir. Thus, at the moment of perforation, fluid from the reservoir enters the wellbore keeping the perforation clean. Several field and laboratory studies have been done and the results, when plotted, showed the minimum underbalanced pressure required to achieve clean perforations. There are cases where underbalanced perforation is not possible, either because the reservoir pressure is not high enough, or for other mechanical reasons. Another technique that has been proven successful in field studies is the extremely overbalanced perforations. In this process, during the perforating procedure, the wellbore is filled with fluid above the perforations and then pressurized with a highly compressible gas. At the instant of perforation, the stored energy in the gas forces the fluid into the perforations, which is believed to cause fractures in the formation and greatly enhance well conductivity. This method is gaining popularity, especially in preparations for hydraulic fracturing.

6.2.6 Production optimization by artificial lift

During the life of a producing field, static reservoir pressure may not be in adequate amount to lift economic flow-rates through the wellbore and overcome surface pressure restrictions. Low production rates are also observed when wellbore fluid gradient increases as a consequence of water presence from the reservoir.

Artificial lift systems objective is to reduce bottom hole flowing pressure and increase flow rate. Artificial gas lift objective is to reduce net hydrostatic gradient by injecting gas lift to the downhole produced fluids. Pump-assisted lift methods aim at boosting downhole pressure by using sucker rod pumps, Electric Submersible Pumps (ESP), progressive cavity pumps or plunger lifts.

Numerous articles related to multiphase flow and artificial lift can be found in the literature. A few of these examples are cited in the references (Economides et al., 1998; Economides and Nolte, 2000; Dusterhoft and Chapman, 1994; Mukherjee, 1999).

As reservoir conditions change with time, artificial lift quantities (gas lift flow, compressor power, pump head, or pump strokes) have to adjust in order to maintain proper fluid production. A continuous depletion of reservoir pressure will cause the bottom hole flowing pressure level sufficiently low as to make the conventional lifting (spontaneous production) inefficient and uneconomic. These situations are ideally suitable for combining different lifting practices such as gas lift and ESP for improved utilization of lifting methodology. Additionally, surface facilities such as gas compression and/or electric power may vary from site to site. Gas usage varies dynamically in accordance with market demand and corporate business strategy, thereby affecting the field performance. On the other hand, some secondary recovery projects may turn out to be uneconomic when the investment cost of artificial lift using...
ESP or gas lift are not appropriately considered.

**Artificial gas lift**

Gas lift consists of compressed gas injection through mandrel valves located along the production tubing close to the perforations with the purpose of changing net flowing fluid density upward (Fig. 15). Wellbore fluid density is reduced with the consequent reduction in pressure loss due to gravity, however with some additional pressure losses due to slippage (slippage of the gas relative to the oil) and friction. Reservoir energy is now sufficient to lift the lighter fluid column to the surface at current tubing head pressure conditions.

Lifting efficiency and hence oil production, is a function of producing Gas/Liquid Ratio (GLR), Water Cut (WCT), lift gas injection pressure, initial injection point depth, crude composition, pipeline and formation characteristics.

**Gas-lift operating features and limits**

The main disadvantages in gas lift are, initial high investment cost for compression, increasing demand for gas lift during reservoir life and uneconomic oil rates at low reservoir pressures. Generally the producing rates increase with increasing lift-gas quantities (see again Fig. 15). There is a maximum gas-lift amount beyond which the production rate will decline. This is because of the fact, that a continuous increase of injection pressure will create additional back pressure towards the reservoir. Also, increasing amounts of gas in the producing tubing will create tremendous friction and pressure drop.

Gas lift is not efficient at very low reservoir pressures, since gas-lift pressure gradient may impose additional backpressure to the formation and avoid any fluid to be produced. Also, gas lift is not convenient at high water cut values, because of high water and gas slippage velocities. However, gas lift is quite effective when there is adequate pressure support and at relatively low water cuts. Moreover, low maintenance is required along well life cycle.

**Dynamic gas-lift automatic control**

Automatic control and optimization is used to inject the optimum gas rate. Given the current conditions of mass flow rate, tubing head pressure and temperature (controlled variables), a closed-loop controller will calculate the optimum gas rate and pressure (manipulated variables) that maximizes flow rate at any time.

For a large number of wells and for variable gas-lift availability (due to compressor plant uptime and market conditions), dynamic automated gas-lift allocation will permit the optimum field production subject to current well models and surface production constraints. This is usually worked out by posing a Linear Programming (LP) problem, solved iteratively on an hourly to daily basis.

**Plunger lift**

Plunger lift (intermittent gas lift) is an artificial lift method principally used in gas wells to unload relatively small volumes of liquid. An automated system mounted on the wellhead controls the well on an intermittent flow regime.

Plunger lift is a type of gas-lift method that uses a plunger which runs up and down inside the tubing. The plunger provides an interface between the liquid phase and the lift gas, minimizing liquid fallback. It has a bypass valve that opens at the top of the tubing and closes when it reaches the bottom.

Plunger lift methods are used to remove water and condensate from a well, but they can handle only a limited column of liquid. Typically, these methods are applied to gas wells with high GLR to operate only with formation gas. Plunger lift methods are good for low-pressure wells and medium fluid gas wells and for lifts fluids using gas pressure. The disadvantages of plunger lift include problems associated with production of solids and limited operating range.

**Sucker-rod pump lift**

The sucker-rod or beam pump system (Fig. 16) uses a downhole mechanical pump which is activated by a sucker rod running inside the producing tubing and driven by a surface walking beam, a crank, a counter weight, a gear reducer and a prime mover (electric or gas motor). The objective is to lift the reservoir fluid column to the surface while reducing well flowing pressure. Thus, lower backpressure is obtained at the reservoir sand face and fluid deliverability is increased.

The sucker-rod pump system has various advantages: is simple and applicable to slim holes and multiple completions, it can pump a well to very low pressures, it can lift high temperatures and viscous oils, it can use gas or electric sources, it can be controlled to work in cycles by time clock at low and high rates.
The disadvantages of the sucker-rod pump system are: the depth limited (by rod size) to 12-16 kft; the problems in gassy wells or high solids wells; the fact that it can be obtrusive in urban locations and bulky for offshore applications.

Electric-submersible pump assisted lift

ESP systems (Economides et al., 1994, 1998) were initiated in Russia during the 1920s, as a producing mechanism for water wells. The technique was later improved in the United States for oil wells. Even if reservoir pressure is relatively low, ESP can be effective for lifting high liquid rates of reservoir fluids. It is also convenient for use in remote areas where no gas compression is available for artificial lift.

Technology consists of a centrifugal pump and motor located at the bottom of the wellbore (Fig. 17) for lifting reservoir fluid column to the surface and reducing well flowing pressure. Thus, lower backpressure is obtained at the reservoir sand face and fluid deliverability is increased.

Fig. 15. Artificial gas-lift configuration (A), pressure gradients (B) and well performance (C).
ESP operating features and limits

The disadvantages for ESP include the relatively high initial investment and the high power requirements; the need for sophisticated monitoring and control systems.

The ESP technology is also limited with high GLR, (e.g. not greater than 30%). The use of a downhole in-line gas separator for high GLR may be required, which will increase the initial investment costs up to 20%. The power is transmitted through a multi-purpose cable. Applications at depth below 18,000 ft have not been successfully implemented due to the limitations of the cable. Initial investment may be in the range of US dollars 100-300 thousand per well. The breakdown of the cost is 40% for the centrifugal pump and motor, 35% for the cable, and the remainder is for the surface components (frequency varicators, electric energy conversion, and monitoring and data transmission units). ESP equipment initial investment is increasingly proportional to the product power requirements and the flow capacity. Their longevity is reduced because they are exposed to rough operating situations such as, high temperature, corrosion, sour crude. Normally, ESP installations last about two years. If premature substitution is required, ESP are definitely less attractive compared to other alternatives, such as gas lift or mechanical pumping.

A reliable energy supply for the electric motor is also required. Portable local generation versus remote hard-wired energy supply is usually compared: a 100 HP portable energy generation unit will cost approximately US dollars 12,800 per month plus any fuel and operating expenses as well. A 5 km surface electric cable network could cost US dollars 15,000. The energy costs will thus range from 9 to 16 cents per kilowatts/hour.

![Fig.16. Several sucker-rod pumps.](image-url)
Progressive cavity pump

Progressive Cavity Pump (PCP) or screw pumps systems consist of a downhole pump driven by a surface motor and connected by a rod. Downhole pumps consist of a metal rotor and an elastomer rubber stator. Stator and rotor have a particular geometric configuration (Fig. 18) to permit multiphase fluid movement in a very efficient way. PCP has proven to be a very cost effective system in many types of oilfield operating environment. The main disadvantage has been the quick and unpredictable deterioration of the stator due to rubber swelling, wearing and break.

Advantages of PCP systems include low bottomhole pressure (intake pressure), low energy consumption and low investment cost. It is also suitable for any viscosity, adequate for high sand content and for high gas amount and high water cut.

The features of progressive cavity pumps include smaller dimensions compared to conventional pumps, minimized hysteresis phenomenon.

Fig. 17. Electric submersible pump configuration (A), pressure gradients (B) and well performance (C).
(longer life time) and best control of rubber swelling. Main applications include crude oil with high aromatics and gas levels, high temperature wells (higher than 220°F), high depth wells (deeper than 6,000 feet) and higher pressure per stage (more than 100 psia).

**Metal-metal progressive cavity pumps**

These pumps are made out of two metals (for the rotor and for the stator). Main applications include high viscosity crude oil (higher than 450 cp), high volumetric efficiency (about 95%), high temperature wells (higher than 400°F) and higher pressure per stage (up to 290 psi).

**Hybrid progressive cavity pumps**

Hybrid progressive cavity pump are made of the combination metal (for the rotor) and thermoplastic material, such as Teflon (for the stator). Main applications include high viscosity crude oil (higher than 100 cp), high volumetric efficiency about 95%, high temperature wells (higher than 350°F) and higher pressure per stage (up to 290 psia). Hybrid progressive cavity pumps are four to five times smaller compared to conventional pumps; they do not imply hysteresis phenomena nor rubber swelling; their expected life time is longer compared to conventional pumps; they have lower torque (there is no friction torque between rotor and stator).

**Jet pumps**

A jet pump is a dynamic displacement pump. It works by boosting a power fluid through a nozzle. The bottom of the pump communicates with the well fluid. The two fluids are mixed with the result that some of the energy of the power fluid is transferred to the well fluid, and it boosts the commingled fluid to the surface either through production tubing or up the annulus between the casing and the injection tubing. At the surface, the power fluid is separated from the oil and sent back to the booster pump to be reused.

The advantages of jet pumps are that, because they have no moving parts, they can be used to lift gassy or dirty fluids without experiencing any of the wear the positive displacement pumps would, and they have no depth limitations. The disadvantages are that they have a low efficiency (20-30%) and they require a high suction pressure to prevent cavitation in the pump. The latter can be remedied by careful calculation of the depth so to provide sufficient suction pressure.

### 6.2.7 Asphaltenes and paraffin control

**Heavy organics deposition**

One of the most common causes of arterial blockage in the petroleum production systems is due to the deposition of heavy organics from petroleum fluids. Heavy organics such as paraffin/wax, resin, asphaltene, diamondoid, mercaptans, and organometallic compounds may exist in crude oil in various quantities and forms. Such compounds could precipitate out of the crude oil solution due to various forces causing blockage in the oil reservoir, in the well, in the pipelines and in the oil production and processing facilities. Solid particles suspended in the crude oil may stick to the walls of the conduits and reservoirs. The hardness of the precipitate depends on the amount of asphaltene present in the crude oil. Being a highly polar compound asphaltene could act as glue and mortar in hardening the deposits and, as a result, cause barrier to the flow of oil.

Heavy organic deposition during oil production and processing is a very serious problem in many areas throughout the world (Leontaritis and Mansoori, 1988). There were wells that, especially at the start of production, would completely cease flowing in a matter of a few days after an initial production rate of up to 3,000 BPD (Barrel Per Day). The economic implications of this problem were tremendous, considering the fact that a problem well workover cost could get as high as a quarter of a million dollars. In Venezuela the...
formation of heavy organics (asphaltic sludge) after shutting in a well temporarily and/or after stimulation treatment by acid has resulted in partial or complete plugging of the well (Lichaa, 1977). At the Hassi Messaoud field in Algeria, deposit of heavy organics in the tubing has been a very serious production problem (Haskett and Tartera, 1965).

Heavy organics have played a significant role in the production history and economics of the deep horizons of the Ventura Avenue field, California (Tuttle, 1983). Heavy organics deposition problems in this field ranged from deposition during early oil production and deposition resulting from well acidizing and CO₂ injection during Enhanced Oil Recovery (EOR). However, the problems were so drastic because of heavy organics (asphalt) deposition at the early history of this field that many wells were redrilled, thus affecting the economics of the project considerably. It was also reported that heavy organics deposits were found in the production tubing in a CO₂ injection EOR pilot (Tuttle, 1983). Generally heavy organics deposits could occur during primary, secondary, and enhanced oil recovery stages (Tuttle, 1983). Heavy organics precipitation, in many instances, carries from the well tubing to the flow lines, production separator, pumps, strainers and other downstream equipment (Katz and Beu, 1945). Heavy organic materials deposited into the production installations of Mexico’s oil fields have caused many operational problems (Chavez and Lory, 1991; Escobedo et al., 1997). For example, in the fields of Tecumonoacan and Jujo, depositions in many wells have caused numerous shutdowns and necessity of rather expensive aromatic washes. Heavy organics deposition in the North Sea and in the Gulf of Mexico oil fields in recent years have caused several under-sea pipeline plugging with substantial economic loss to the oil production operations.

In general, solids in crude oil fall into two classes: basic sediment and filterable solids. These particles have an economic impact on petroleum industry. Carried along in the oil, they can cause fouling, foaming, erosion, corrosion, etc. Depending on the case, coagulants (molecular weight <10,000) or flocculents (molecular weight >10,000), might provide an indirect aid in solids removal (Schantz and Elliot, 1994). Coagulants are molecules with strong polar charge, which act to disrupt charges on the surface of the oil droplet that would otherwise prevent coalescence. Flocculents act to coalesce oil droplets, because they are very soluble in oil, but in some cases they can have drastically reduced solids removal.

**Asphaltenes and paraffin deposition and control**

Asphaltenes are large aromatic agglomerates composed primarily of heterocyclic rings. Held in solution in crude oil by naturally occurring petroleum resins that adhere to the outer surface of the asphaltene agglomerate, they will precipitate and deposit in the production system in locations where pressure drops allow the resins to desorb.

Paraffins are saturated hydrocarbon waxes that will precipitate and deposit in areas where the temperature of the petroleum production system falls below the solubility temperature of the paraffins, known as the Wax Appearance Temperature (WAT). Unlike asphaltenes, paraffins can block a production system and completely stop production.

Several dispersants and solvents on the market offer the capability to remove paraffin and asphaltene deposits and restore a production system to its designed capacity. Those solvents remove paraffin and asphaltene deposits when used in batch treatments by simply dissolving the deposits. Some dispersants contain oil-soluble surfactants that break up the paraffin or asphaltene deposit and disperse it in the oil.

Some products can be used in continuous injection applications to control deposition of waxes and asphaltenes, although the normal procedure is to remove existing deposits through batch treatment. The volume of chemical and frequency of treatment required for batch treatments will depend primarily on the severity of the problem. Once existing paraffin and asphaltene deposits are removed, continuous injection treatment provides a cost-effective approach to maintaining a system with no production-inhibiting deposits.

Proper treating recommendations for cost-effective control of paraffins and asphaltenes are complicated by the differences in characteristics of the produced oil, variations in system operating conditions and the wide variety of chemicals available for use. Selection of the proper chemical and treating method should be based on laboratory and field tests.

### 6.2.8 Workovers in case of casing and tubing collapse or in case of lack of cement

**Wellbore mechanical integrity**

Wellbore mechanical integrity problems (casing leaks) may have different sources: holes caused by gas leakages, corrosion or wear, splits caused by flaws, excessive pressure or formation deformation. Casing leaks can result in pump failure or stuck pump; they typically occur above the top of the cement and/or through invasion of drilling mud. Wellbore mechanical
integrity failure will affect the isolation function of the casing and cement. Communication problems will rise as unexpected channels behind casing, barrier breakdowns, completion into or near water, coning and cresting, channeling through high perm zones or fractures and fracturing out of zone.

Mechanical integrity tests can be determined by pressure testing or casing inspection logs. In some instances a fluid level shot assists in locating casing leak. Pressure testing is required on injection and disposal wells by certain regulatory agencies. Isolate leaks use RBP (Retrievable Bridge Plug) and packer. The majorities of leaks occur where there is no cement behind the casing. It is necessary to use compatible fluid with producing formation, otherwise it can cause further damage in bad casing.

Casing inspection logs include multi-fingered calliper logs, Electrical Potential (EP) logs, electromagnetic inspection devices and borehole tele-viewers. Most measures extent to which corrosion has occurred; EP log indicates where corrosion is currently occurring.

Remedial actions include cement squeeze, polymer squeeze, combination squeeze and liner/casing patches.

Remedial cement

This is a remedial cementing operation designed to force cement into leak paths in wellbore tubulars. The required squeeze pressure is achieved by carefully controlling pump pressure. Squeeze cementing operations may be performed to repair poor primary cement jobs, isolate perforations (production levels) or repair damaged casing or liner. Cement squeeze is the careful application of pump pressure to force a treatment fluid or slurry into a planned treatment zone. In most cases, a squeeze treatment will be performed at downhole injection pressure below that of the formation fracture pressure. In high-pressure squeeze operations, performed above the formation fracture pressure, the response of the formation and the injection of treatment fluid may be difficult to predict.

Cement squeezing is basically a filtration process in which cement slurries subject to differential pressure against a filter of permeable rock lose part of their mix water, leaving a cake of partially dehydrated cement particles. The rate of cake buildup depends on formation permeability, differential pressure applied, time and capacity of slurry to lose fluid. Ideal slurry controls rate of cake growth so uniform that a filter cake builds over all permeable surfaces. A technique known as hesitation squeeze cementing involves the dehydration of the cement slurry by intermittent application of pressure, interspersed by periods of pressure leak-off caused by loss of filtrate to the formation.

Low-pressure squeezing implies injecting below fracturing pressure, near the wellbore, low volumes in depleted formations of spot cement at perforations so to prevent fracturing due to hydrostatic pressure.

High-pressure squeezing breaks down formation, fills fractures or microannuli; location and orientation cannot be controlled and properly performed and it leaves cement close to wellbore.

Before cementing operations commence, engineers determine the volume of cement (commonly with the help of a caliper log) to be placed in the wellbore and the physical properties of both the slurry and the set cement needed, including density and viscosity. A cementing crew uses special mixers and pumps to displace drilling fluids and place cement in the wellbore.

Polymer squeezes

They are used as alternative or in combination with cement. Type of polymer and process depends on the location and severity of leak and whether squeeze is required to hold pressure or block encroachment of water. Advantages of polymer squeezes include the wash out of wellbore after squeeze and lower hydrostatic pressure.

Four basic gel systems are used: acrylic monomer grout, high concentration low molecular-weight polymer, high molecular-weight polymer and cement/polymer combination.

Liner and casing patches

When liner or casing objectives for remediation are determined, patches are an alternative for fixing such problems. They are permanently installed in casing or incorporated as part of tubing string. Those patches are available in different lengths and diameters. Once installed, they may restrict internal diameter of casing. Some patches incorporate sealing elements attached to tubing string (they may or may not have vent tubes). One important aspect to bear in mind when installing these patches is to consider future uses or operations of the well and how these tools could have an effect on the accessibility of the downhole tools.

6.2.9 Well architecture for production optimization

Completion options: inclination, production hole, commingling

Vertical versus horizontal

Depending on reservoir properties, drive mechanisms and future enhanced oil recovery projects, there can be advantages to one type versus the other.
The cost of drilling a horizontal well is more than that of a vertical well; completion costs are also usually higher. Therefore, the volume of salable products must be higher in order to have a higher Return On Investment (ROI).

The basic benefit of a horizontal well from a reservoir engineering perspective is the generation of a line sink versus a point sink. This geometry makes more efficient use of reservoir pressure, illustrated by radial flow in the vertical well versus linear flow in the horizontal well. A horizontal well can produce at higher rates than a vertical well at similar drawdown, or can produce similar rates at lower drawdown, thus delaying coning in the case of a bottom-water/drive reservoir.

Case histories indicate that reservoirs thinner than 200 feet and having a permeability of less than 100 md should be considered for a horizontal well. A reservoir with vertical permeability greater than one-fourth of its horizontal permeability, a horizontal well might be beneficial. The use of horizontal wells grants another technique to reduce water or gas coning/cresting while producing at higher hydrocarbon rates than those produced from vertical wells. Case histories have proven that critical oil rates are three to twenty times higher in horizontal wells than in vertical wells.

Heterogeneous reservoirs, such as layered formations and dipping layered formations that can be thick with high permeabilities, and be with or without gas caps and bottom water, can be produced effectively using horizontal wells. However, the heterogeneity has to be defined, the well profile has to be designed to handle the heterogeneity, and the wellbore’s trajectory must be oriented from the geologic information gathered as drilling progresses. Large production improvements can be achieved in heterogeneous reservoirs. Reservoirs have been increased by as much as factor of 6 in the Austin chalk in South Texas. Partially depleted and flooded reservoirs can be more effectively drained using horizontal wells. In general the production increase of horizontal versus unstimulated vertical wells is proportional to the reservoir’s area contacted by the wells. Due to exposing more of the formation to drilling fluids for longer periods, formation damage may be more pronounced in horizontal wells when problems with drill fluids are encountered.

**Open hole versus perforated**

The open hole method is initially cheaper, since perforating costs are eliminated. This method permits testing of the zone as it is drilled, eliminates formation damage by drilling mud and cement, and allows for incremental deepening as necessary to avoid drilling into water. This last factor is important in thin, water-drive pay sections where no more than a few feet of oil zone penetration are desired. On the other hand, the perforated completion offers a much higher degree of control over the pay section, since the interval can be perforated and tested as desired. Individual sections can, in general, be isolated and selectively stimulated much more easily and satisfactorily.

There is considerable evidence that hydraulic fracturing is more useful in perforated completions. Productivity ratios of perforated wells are about 50% higher than those of similar open hole completions. This superiority is apparently due to uniform treatment over the entire pay section plus the stimulation benefit gained from penetration of the perforations themselves. The improved zonal control is also of value when remedial measures, such as water or gas exclusion, are undertaken.

With perhaps a few exceptions in low pressure or thin water-drive pay areas, benefits of the perforated completion overshadow those of the open hole type. This advantage has been made possible by modern perforating and stimulation techniques and advances in drilling muds, cementing materials and methods, as well as other aspects of petroleum technology.

**Single zone versus commingled**

Most wells are initially completed in a single zone. As production matures and the oil rate declines, other zones may be opened to keep the well economic. Sometimes the initial zone is plugged off prior to recompletion; other times, if it still produces some oil, it is left open or later commingled with other zones. Commingling zones within the same wellbore considers: *a*) compatibility of fluids (mixing different formation fluids tends to increase scale and corrosion problems); *b*) reservoir pressure of the different zones (you don’t want one zone to thieve production from another); *c*) if unexpected things occur, such as increased water production, so that it becomes more difficult and costly to determine which zone is the culprit; *d*) whether the well will ever be used as part of an improved oil recovery project, such as a waterflood.

**Other completion options: use of downhole water separator**

This includes all potential production scenarios prior to drilling and completing a well, e.g. the use of downhole oil-water and gas-water separators. This technology, where a well serves as both a producer and an injector, is advancing rapidly and may be more commonly used in the future. Questions to consider prior to drilling are if well should be drilled deeper to have access to a disposal zone and what size casing
should be set to accommodate special tools and equipment.

**Horizontal wells**

Hydraulic fractures have a distinctly defined azimuth and for the vast majority of cases are vertical and normal to the minimum horizontal stress direction. One of the unfortunate events in fracturing is that the fracture azimuth is often the least favourable in that the minimum horizontal stress direction is also the direction of minimum permeability. Thus, the smallest permeability is the dominant problem in flow from the reservoir into the fracture (Economides, 1993).

Horizontal wells can be drilled as an alternative to hydraulically fractured vertical wells and Brown and Economides (1992) have presented a series of studies comparing the performance of horizontal vs. fractured vertical wells. A more advanced concept is that the horizontal well can be drilled exactly in the favourable direction, i.e. normal to the maximum horizontal permeability. In highly anisotropic reservoirs this would further tilt the decision in favour of horizontal wells.

**Fracturing horizontal wells**

Horizontal wells can also be fractured and they can be drilled either normal to the fracture azimuth (which will result in transverse fractures) or longitudinal to the fracture azimuth (which will result in longitudinal fracture). The first configuration is applicable in relatively low permeability formations, while the second configuration is applicable in higher permeability formations (Economides, 1993).

In high-permeability formations, fractured vertical wells always yield finite conductivity fractures, which can be remedied to an extent if the TSO technique is used. Fracturing horizontal wells longitudinally (Economides, 1993; Valkó and Economides, 1996) provides an infinite conductivity streak in an otherwise finite conductivity medium. A longitudinally fractured horizontal well provides for a smaller pressure drop than the pressure drop in a fracture intersecting a vertical well. Thus, the longitudinally fractured horizontal well not only deserves further attention but it could be one of the most powerful tools in production enhancement. Such a completion of course can only be considered if, the incremental costs over a fractured vertical well or an unfractured horizontal well can be covered by the discounted incremental revenue. It is important to determine whether such a configuration is logistically possible. In certain formations, well trajectories along the required maximum horizontal stress direction are either not feasible or extraordinarily difficult (Vilegas et al., 1996).

Valkó and Economides (1996) showed that the performance of a longitudinally fractured horizontal well is often superior to a fractured vertical well or an unfractured horizontal well. In 1-10 md reservoirs, the longitudinally fractured well behaves as an infinite conductivity fractured well. At 100 md, the longitudinally fractured well is still more productive than the fractured vertical well and an unfractured horizontal well. However, this configuration does not behave as an infinite conductivity fractured well anymore. Valkó and Economides also showed that a horizontal well fractured longitudinally with tenfold less proppant, still outperforms the fractured vertical well of permeability 1-10 md, and it is still competitive at 100 md.

High permeability fracturing does not only mean wide fractures, which can be obtained only by TSO technique. The combination of horizontal wells and longitudinal moderate-width fracturing may provide the optimal configuration. Furthermore, dimensionless fracture conductivity around unity is not necessary if the fracture is intersected by a horizontal well instead of a vertical well. However, the relative advantage with fractured horizontal wells increases as the ratio of the formation thickness to the fracture half-length (i.e. $h_D = h/s_{fr}$) decreases (Valkó and Economides, 1996).

In the case of vertical-to-horizontal anisotropic formations, the vertical component of the flow adds another dimension to the problem, thus, it becomes a 3-D problem. The index of anisotropy, $I_{an}$, is the square root of the horizontal-to-vertical permeability ratio (Economides, 1993):

\[
I_{an} = \sqrt{\frac{k_H}{k_V}}
\]

where $k_V$ is the vertical and $k_H$ is the horizontal permeability which is taken as the square root of the product of the two main horizontal permeabilities.

Vilegas et al. (1996) conducted a study to evaluate the effects of both vertical and areal permeability anisotropy on the performance of longitudinally fractured horizontal well. Their results showed that the vertical anisotropy has little effect on the pressure and rate performance and the response of the fractured horizontal well is not very sensitive to the horizontal-to-vertical anisotropy. In fact, vertical-to-horizontal permeability anisotropy, a major problem in horizontal wells (e.g., in laminated reservoirs), can be corrected with hydraulic fracturing. In the Vilegas et al. study, the response of a fractured vertical well in an isotropic formation is outperformed by a longitudinally fractured horizontal well for any degree of anisotropy. However, the horizontal anisotropy causes a reduction in the fractured well production rate. For large areal
permeability anisotropy, an unfractured, optimally oriented horizontal well (i.e. drilled into the minimum horizontal stress and, thus, normal to the maximum permeability) becomes more attractive, compared to any fractured well.

**Complex wells**

The emergence of complex wells offers a number of potential ideas for new configurations. Some of these ideas can eventually replace the fracturing of simple horizontal wells and even vertical wells. The problems that can be addressed deal both with incremental production but also with peripheral issues such as wellbore stability. For example, while in many formations the performance of fractured horizontal wells would be theoretically superior to that of vertical wells, the requirement in high-permeability reservoirs to drill the horizontal well along the maximum horizontal stress may cause long-term stability problems.

One way to circumvent the problem is to take the very bold step to drill a horizontal well in a competent formation above or below the target reservoir and execute a fracture which will penetrate the potentially unstable formation. Hence production is accomplished through the fracture into a well that acts as a mere conduit to flow.

Another, even more innovative idea is to drill a horizontal mother bore and then drill vertical branches off the mother bore into the reservoir (Economides *et al.*, 1998). This type of configuration would allow for the placement of the horizontal borehole in a competent, more stable, non-producing interval. There are several clear advantages in fracturing vertical instead of horizontal branches: avoidance of tortuosity, fracture turning and multiple fracture problems; moreover, perforating strategy is much simplified and choke effects are much less of a problem. Certainly, a configuration such as this, which with proper branch spacing could produce as much as the same number of vertical wells, has considerable limitations in design, execution and zonal isolation.

### 6.2.10 Operation and maintenance of petroleum production systems

**Corrosion control**

The production of gas and oil is often accompanied by water, either from the formation, from condensation, or from water injected as lift assist. Acid gases, such as hydrogen sulfide (H₂S) and carbon dioxide (CO₂), are often present in produced fluids, and oxygen is sometimes a contaminant in the water used for injection. These acid gases increase the corrosivity of the waters to steel, and can significantly reduce the safe operating life of production tubular and equipment, production vessels, and transportation systems.

The presence or absence of multiple phases (gas, water, and oil or condensate) in the same system can complicate the problem of controlling corrosion. The flow regime or pattern of fluids in a tubing string, vessel, or pipeline can have a significant impact on corrosivity.

If a well or pipeline experiences slug or intermittent flow, highly corrosive conditions may exist.

Pipelines can experience top-of-line corrosion when conditions promote the rapid condensation of water in a cooler section of the line, causing a film of water to form at the top of the line. This water becomes saturated with acid gases and corrodes the pipe. A further complication is a change in conditions, such as flow rate, temperature, and pressure over the life of a well, production or processing system, or pipeline, which can result in changing corrosivity or even a change in the potential corrosion mechanisms.

The control of corrosion in the oilfield can be a complex problem, requiring detailed analysis and a thorough understanding of the range of conditions expected during the life of the system prior to the development of a corrosion management plan.

Corrosion-inhibitors formulations have been developed to address specific and wide applicability corrosion problems. Applications include controlling corrosion in all types of oilfield operations, including oil and gas production, processing, and transportation systems.

The composition of the particular oilfield brine, the system temperature, and the composition of hydrocarbons in the system affect the solubility and partitioning of oilfield corrosion inhibitors. Selection of the adequate inhibitor is achieved by having a thorough knowledge of the interplay of system effects on the performance of a corrosion inhibitor and knowledge of production operations.

This profit enhancement is accomplished by extending asset life, reducing failure rates, maintaining the operability of the systems, and by allowing operators the ability to manage risk associated with corrosion.

**Bacteria control in the oilfield**

Bacteria frequently become a significant problem in petroleum drilling, completion, production, processing, and transportation operations. Bacteriological effects include reservoir fouling, production of biogenic (bacterially-generated)
hydrogen sulphide (H₂S), plugging and corrosion of production equipment, corrosion and fouling of heat exchange equipment, corrosion and permeability damage in water disposal or waterflood systems, and corrosion and product deterioration in transportation systems such as pipelines and storage tanks. If not properly managed, these problems may impact an operator’s ability to maintain production levels, control operating costs, and ultimately, reduce the profits from operations. These problems impact profit through lowered production revenues; the need for costly well interventions; increased piping and equipment maintenance or repair costs; or the use of hydrogen sulphide scavengers to control biogenic H₂S at levels safe for personnel and equipment, and to meet regulatory or contractual agreements. Several market products and services are available for the management of bacteria in drilling, production, processing, and transportation operations. Biocides and other formulations are designed to control bacteria populations and the resulting damage caused by bacterial action. Each application is evaluated thoroughly, to select the appropriate product, application technology, and monitoring systems.

**Scale control**

Scale is defined as deposits of insoluble inorganic minerals. Common oilfield scales include calcium carbonate, barium sulphate, and metal sulphides. While deposition of calcium carbonate scales depends partially on pH and pressure, scale deposits generally occur when waters from different sources, and different ion content, are mixed. Scale deposits can quickly block production tubulars and stop production. In many cases, scale deposits can be dissolved, but for some scales, calcium fluoride in particular, mechanical removal is the only remedy.

There are several steps involved prior to the actual deposition of the scale on a pipe wall or in surface equipment. Prevention of scale can occur at several levels in the process. The methods used to control scale deposition vary, and are often chosen based on the application methods available as well as the economics of the process. While chelation may be the most technically effective method for scale control, the cost is high, because there is a one-to-one, or maybe even greater, relationship required between the chelant molecule, such as ethylene diamine tetraacetic acid (EDTA) and the scale, whereas crystal growth modification is a threshold process, whereby a small number of growth inhibitor molecules can slow or prevent the growth of a number of scale crystals.

Scale inhibitors are based on three types of compounds: phosphate esters, phosphonates and polymers. Phosphate esters are more tolerant of acid conditions than the polyphosphates and are stable to temperatures of 150-160°F (65-71°C). They can withstand temperatures of 180-200°F (82-93°C) for a few hours. Within these temperature limitations, phosphate esters are generally excellent inhibitors for calcium carbonate (CaCO₃) and calcium sulphate (CaSO₄). Except in acid environments (pH<5.5), they also provide excellent control of strontium sulphate (SrSO₄) and barium sulphate (BaSO₄) precipitation. In general, phosphate esters are soluble in- and compatible with- high calcium brines.

Several different types of phosphonates are used as scale inhibitors. Each type has different characteristics of thermal stability, calcium tolerance, and efficiency against the various types of scales. Phosphonate scale inhibitors are supplied in the acid form or with any portion of the acidity neutralized by ammonia, amines or alkaline hydroxides. This provides an even broader range of characteristics.

The organic polymers most often used as scale inhibitors are the low molecular weight polyacrylics. Polymers generally provide fair to good results in typical oilfield brines by laboratory anti-precipitation tests. However, polymers function primarily as crystal distorters, i.e. they might permit precipitation of the scale-forming compounds, but polymers modify/distort the shape of the scale crystals so that they will not grow or adhere to other surfaces.

Polymers are stable to 400°F (204°C) or higher. They are generally effective at very low concentrations for control of CaCO₃ and BaSO₄ in waters containing low concentrations of scale-forming ions. They are also effective under acidic conditions, particularly in the control of BaSO₄. Polymers are often blended with other types of scale inhibitors to obtain a single product with a broader range of applications.

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MICHAEL J. ECONOMIDES
LUIGI SAPUTELLI
Department of Chemical Engineering
University of Houston
Houston, Texas, USA