MAJOR PROJECT ON
HYDRAULIC FRACTURING
OF
OIL & GAS
WELLS

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CERTIFICATE

This is to certify that *Siddarth Raja and Vyomesh Gupta* students of *B.Tech (Applied Petroleum Engineering - Upstream)* has written their Dissertation on *"Hydraulic Fracturing Of Oil And Gas Wells"* under my supervision and have successfully completed the project within stipulated time.

They have demonstrated high performance levels and dedication during the completion of their Dissertation.

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ABSTRACT

Since its introduction, hydraulic fracturing has been, and will remain, one of the primary engineering tools for improving well productivity. This is achieved by:

• placing a conductive channel through near-wellbore damage, bypassing this crucial zone
• extending the channel to a significant depth into the reservoir to further increase productivity
• placing the channel such that fluid flow in the reservoir is altered.

In this last instance, the fracture becomes a tool for true reservoir management including sand deconsolidation management and long-term exploitation strategies. As first visualized, the concept of hydraulic fracturing was quite straightforward. This visualization is described in the following, and in general, for reasonably simple geology, the basic physics of fracturing is straightforward and well established. Complexity arises from two directions: geologic reality and the inherent multidisciplinary nature of the fracturing process.

Historically, the control of fracturing has rested with drilling and operations groups owing to the nature field procedures using pumps, packers, pressure limits, etc. However, the final results (and thus design) are dominantly a production engineering exercise, and fracturing cannot be removed from intimate contact with reservoir engineering. At the same time, designing a treatment to achieve the desired results is also intimately connected with rock mechanics, fluid mechanics and the chemistry that governs the performance of the materials used to conduct the treatment. However, the design must also be consistent with the physical limits set by actual field and well environments. Also, treatments must be conducted as designed to achieve a desired result. Proper treatment design is thus tied to several disciplines:

• Production engineering
• Rock mechanics
• Fluid mechanics
• Selection of optimum materials
• Operations.

Because of this absolutely essential multidisciplinary approach, there is only one rule of thumb in fracturing: that there are no rules of thumb in fracturing.

The multidisciplinary nature, along with the difficulty in firmly establishing many of the design variables, lends an element of art to hydraulic fracturing.

The following report is aimed at understanding the principles and various processes involved in hydraulic fracturing. It includes the basic process, fluid system, proppants, perforation nature etc. it also includes a case study based on designing of fracturing. it should be noted that fracture models and softwares used in hydraulic fracturing simulation are out of the scope of the project.

HISTORY

The first attempts at fracturing formations were not hydraulic in nature – they involved the use of high explosives to break the formation apart and provide "flow channels" from the reservoir to the wellbore. This type of reservoir stimulation reached its ultimate conclusion with the experimental use of nuclear devices to fracture relatively shallow, low permeability formations in the late 1950's and early 1960's.

In the late 1930's, acidizing had become an accepted well development technique. Several practitioners observed that above a certain "breakdown" pressure, injectivity would increase dramatically. It is probable that many of these early acid treatments were in fact acid fractures.

In 1940, Torrey recognized the pressure-induced fracturing of formations for what it was. His observations were based on squeeze cementing operations. He presented data to show that the pressures generated during these operations could part the rocks along bedding planes or other lines of "sedimentary weakness". Similar observations were made for water injection wells by Yuster and Calhoun in 1945.

The first intentional hydraulic fracturing process for stimulation was performed in the Hugoton gas field in western Kansas, in 1947. The Klepper No 1 well was completed with 4 gas producing limestone intervals, one of which had been previously treated with acid. Four separate treatments were pumped, one for each zone, with a primitive packer being employed for isolation. The fluid used for the treatment was war-surplus napalm, surely an extremely hazardous operation. However, 3000 gals of fluid were pumped into each formation.

Although post treatment tests showed that the gas injectivity of some zones had been increased relative to others, the overall deliverability from the well was not increased. It was therefore concluded that fracturing would not replace acidizing for limestone formations.

However, by the mid-1960's, propped hydraulic fracturing had replaced acidizing as the preferred stimulation method in the Hugoton field. Early treatments were pumped at 1 to 2 bpm with sand concentrations of 1 to 2 ppa.

Today, thousands of these treatments are pumped every year, ranging from small skin bypass fracs at $20,000, to massive fracturing treatments that end up costing well over $1 million. Many fields only produce because of the hydraulic fracturing process. In spite of this, many industry practitioners remain ignorant of the processes involved and of what can be achieved.

PROCESS

Hydraulic fracturing occurs as a result of the phenomenon described by Darcy's law for radial flow:-

$$q = \frac{kh\Delta P}{\mu \ln(r_e/r_w)} \qquad (1.1)$$

Where q is the flow rate, k the formation permeability, h the net height, ΔP the pressure differential (or drawdown), μ the fluid viscosity, r_e the drainage radius and r_w the wellbore radius. This Equation describes the flow rate for a given reservoir-wellbore configuration, for an applied pressure differential. Re-arranging this Equation gives a different emphasis:

$$\Delta P = \frac{q \mu \ln(r_e/r_w)}{kh} \quad \text{......} (1.2)$$

This Equation describes the pressure differential produced by a given flow rate. Remembering that Darcy's Equation applies equally to injection and to production, Equation 1.2 tells us the pressure differential needed to pump a fluid of viscosity μ into a given formation at a given rate q.

As the flow rate increases, the pressure differential also increases. Pressure and stress are essentially the same thing (discussed later), so that as the fluid flow generates a pressure differential, it also creates a stress in the formation. As flow rate (or viscosity) increases, so does the stress. If we are able to keep increasing the rate, eventually a point will be reached were the stress becomes greater than maximum stress that can be sustained by the formation – and the rock physically splits apart.

This is how we frac, by pumping a fluid into a formation at high rate and – consequently – high pressure. However, it is important to remember that it is pressure – not rate – that creates fractures (although we often use rate to create the pressure).

Pressure – and stress – is stored energy, or more accurately stored energy per unit volume. Energy is what hydraulic fracturing is all about. In order to create and propagate a fracture to useful proportions, we have to transfer energy to the formation. Producing width and physically tearing the rock apart both require energy. Overcoming the often highly viscous frac fluid's resistance to being pumped also takes energy. So the key to understanding the hydraulic fracturing process is to understand the sources of energy gain, such as the frac pumps and the well's hydrostatic head, and the sources of energy loss and use. The sum of these is always equal to zero.

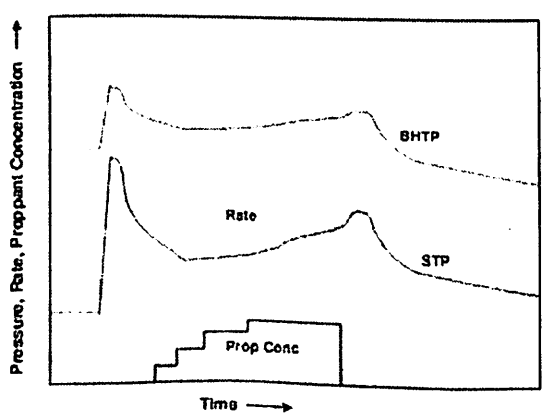
As pressure is energy, a great deal can be learned about a formation by studying the pressures produced by a treatment. The product of the pressure and the flow rate gives us the rate at which energy is being used, i.e., work. This is usually expressed as hydraulic horsepower. The analysis of the behaviour of fracturing pressures is probably the most complex aspect of the process that most Frac Engineers will become involved in. Once a fracture has been created, proppant is placed inside it. If the treatment has been designed effectively and pumped without any problems, then this proppant should form a highly conductive path from the reservoir to the wellbore. This is what makes the well produce more.

BASIC PROCESS

As fluid is pumped into a permeable formation, a pressure differential is generated that is proportional to the permeability of the formation, k_f . As the rate increases, this pressure differential between the wellbore pressure and the original reservoir pressure also increases. This pressure differential causes additional stress around the wellbore. Eventually, as the rate is increased, this pressure differential will cause stresses that will exceed the stress needed to break the rock apart, and a fracture is formed. At this point, if the pumps are shut down or the pressure is bleed off, the fracture will close again. Eventually, depending on how hard the rock is and the magnitude of the force acting to close the fracture, it will be as if the rock had never been fractured. By itself, this would not necessarily produce any increase in production.

However, if we pump some propping agent, or proppant, into the fracture and then release the pressure, the fracture will stay propped open, providing the proppant is stronger than the forces trying to close the fracture. If this proppant also has significant porosity, then under the right circumstances a path of increased permeability has been created from the reservoir to the wellbore. If the treatment has been designed correctly, this will produce an increase in production.

Generally, the process requires that a highly viscous fluid is pumped into the well at high rate and pressure, although this is not always the case (see Skin Bypass Fracturing, below). High rate and high pressure mean horsepower, and this is why the process generally involves large trucks or skids with huge diesel engines and massive pumps. A typical frac pump will be rated at 700 to 2700 hydraulic horsepower (HHP) – to put this in perspective, the average car engine (outside North America, that is) has a maximum power output of 80 to 100 HP. In order to create the fracture, a fluid stage known as the pad is generally pumped first. This is then followed by several stages of proppant-laden fluid, which actually caries the proppant into the fracture. Finally, the whole treatment is displaced to the perforations. These stages are pumped consecutively, without any pauses. Once the displacement has finished, the pumps are shut down and the fracture is allowed to close on the proppant. The Frac Engineer can vary the pad size, proppant stage sizes, number of proppant stages, proppant concentration within the stages, the overall pump rate and the fluid type in order to produce the required fracture characteristics.



TYPICAL HYDRAULIC FRACTURING JOB PLOT

PRESSURE

Everybody understands what pressure is. Or at least, everyone thinks they understand what pressure is. If you ask someone to define pressure, then they will usually say. "force divided by area". or something similar. This is not what pressure is - it is merely how we measure, create and use pressure.

The simple fact is that pressure is stored energy, and we use that energy to perform work on the formation during the fracturing process. Everything we do in fracturing can be thought of in terms of energy. For instance, when we pump a fluid into a fracture we start out with chemical energy – in the form of diesel fuel. This is converted to mechanical energy by the diesel engine. The high pressure pump then transfers this mechanical energy into pressure in the fracturing fluid. As the fluid moves into the formation, the pressure is transformed into stress in the formation, which is another form of stored energy, and so the walls of the fracture are pushed back, creating fracture width and forcing the fracture to propagate.

Work is defined as the rate at which energy is used – in the SI system; one watt is defined as a joule per second. Therefore, by observing the way the pressure is changing, or not changing, with respect to time, we can tell how much work we are performing on the formation.

Pressure and stress is essentially the same thing. The only difference is that stresses act in solids and pressures act in liquids and gases. Because liquids and gases easily deform away from any applied force, pressures tend to act equally in all directions. Stresses, however, tend to act along planes, so that a solid experiencing a stress will always have a plane where the stresses are a maximum, and a plane perpendicular to this where the stresses are at a minimum.

In fracturing, we refer to several different pressures. These names merely refer to where and when we are measuring (or calculating) the pressure;

Surface Treating Pressure, STP – also referred to as wellhead pressure, injection pressure, tubing pressure (if we are pumping down the tubing), P_{STP}, $P_{wellhead}$, P_{tubing} and so on. The name speaks for itself – it is the pressure that the pumps have to act against at the surface.

Hydrostatic Pressure – also referred to as hydrostatic head, P_H, HH and P_{hydro}. This is the pressure downhole due to the weight of the column of fluid in the well. This pressure is a function of the density of the fluid and the vertical depth:

$$HH = 0.433\ g\ TVD \qquad \text{(A)}$$

where HH is the hydrostatic head in psi, g is the specific gravity of the fluid and TVD is the true vertical depth at which the pressure is acting. This looks relatively easy to calculate, but can get quite complicated in a dynamic system in a deviated well with fluids of several different densities actually in the well – which is the usual situation during a frac job. We use computers to keep track of this.

Tubing Friction Pressure – also known simply as friction pressure, P_{frict} or ΔP_{frict}. We can define it qualitatively as the pressure caused by the resistance of the fluid to flow down the tubing. Friction pressure decreases with increasing tubular diameter and increases with rate.

Bottom Hole Treating Pressure – BHTP or P_{BHT}. This is the pressure inside the well, by the formation being treated. Generally, at is calculated at the center of the perforated interval. At this point, the fluid has not passed through the perforations or into the fracture. Unless there are gauges in the well, or there is a static column, this pressure is usually calculated:-

$$BHTP = STP + HH - \Delta P_{frict} \text{ .... (B)}$$

As there are always uncertainties with the calculation of ΔP_{frict} (unless fluid rate is zero), there will always be uncertainties in calculated BHTP.

Perforation Friction Pressure – also known as perforation friction or ΔP_{perf}. This is the pressure drop experienced by the fluid as it passes through narrow restrictions generally referred to as perforations:-

$$\Delta P_{perf} = 2.93\ SG\ (q/n)^2/d^4 \text{ .... (C)}$$

where ΔP_{perf} is in psi, SG is the specific gravity of the fluid, q is the slurry rate in bpm, d is the perforation diameter in inches and n is the number of perforations.

Near Wellbore Friction Pressure – a.k.a. near wellbore friction or ΔP_{nwb}. This is the sum of the perforation friction and any pressure losses caused by tortuosity,

Closure Pressure – P_c or $P_{closure}$. This is the force acting to close the fracture. Below this pressure the fracture is closed, above this pressure the fracture is open.

Extension Pressure – or P_{ext}. This is the pressure required in the frac fluid in the fracture in order to make the fracture propagate. It is usually 100 to 200 psi greater than the closure pressure, and this pressure differential represents the energy required to actually make the fracture propagate, as opposed to merely keeping it open (i.e. $P_{closure}$). In hard formations, fracture extension pressure is close to the closure pressure. In softer formations, where significant quantities of energy can be absorbed by plastic deformation at the fracture tip, extension pressure can be significantly higher than closure pressure. The fracture extension pressure can be obtained from a step rate test.

Net Pressure – or P_{net}. This is a fundamental value used in fracturing and the analysis of this variable forms a whole branch of frac theory by itself. Pnet is the difference between the fluid pressure in the fracture and the closure pressure, such that:-

$$P_{net} = BHTP - \Delta P_{nwb} - P_{closure} \text{ .... (D)}$$

$$= STP + HH - \Delta P_{frcit} - \Delta P_{nwb} - P_{closure} \text{ .... (E)}$$

P_{net} is a measure of how much work is being performed on the formation. By analyzing the trends in P_{net} a great deal can be determined about how the fracture is growing – or shrinking.

Instantaneous Shut in Pressure – or ISIP or ISDP. This is the pressure, which can be determined either at surface or bottom hole, which is obtained just after the pumps are shut down, at the start of a pressure decline. If measured at bottom hole, the ISIP should be equal to the BHTP, provided P_{nwb} is zero.

BASIC FRACTURE CHARACTERSTICS:

Every fracture, regardless of how it was pumped or what it is designed to achieve, has certain basic characteristics, as shown in figure below.

All fracture modeling is designed around determining these three characteristics, height H, half length x_f and width W. Once these three characteristics have been determined, other quantities such as proppant volume, fracture conductivity and ultimately production increase can be determined. It is usually assumed that the two wings of the fracture are identical and 180° apart (i.e. on opposite sides of the wellbore. This is not necessarily the case. It is also normal to model the fracture wings as being elliptical in shape - however, the reality is that the geometry is probably quite a bit more complex. However, based on the three characteristics of width, half length and height, we can define a few simple parameters:

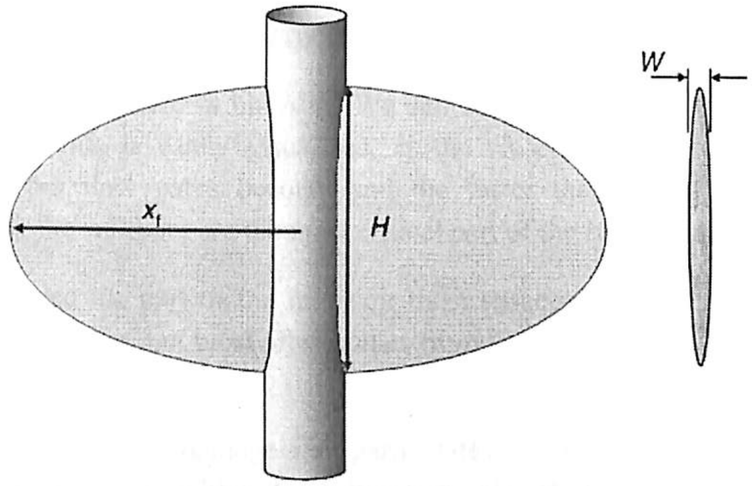


Diagram showing fracture half Length x_f, fracture height H, and fracture width W

Aspect ratio;

$$AR = H/xf$$

So a radial frac, which is perfectly circular and has a height equal to twice the fracture half length, has an AR of 0.5

Fracture conductivity;

$$F_c = \overline{w}.k_p$$

where $\overline{w}$ is the average fracture width and k_p is the permeability of the proppant pack.

Remember that the width in above equation is the propped width, which is usually less than the width actually created during the treatment. The propped width is a function of the volume of proppant pumped into the fracture, expressed in terms of the mass of proppant per unit area of the fracture face. This areal proppant concentration is expressed in terms of lbs/sq ft, and is not to be confused with the slurry proppant concentration, that is expressed in lbs/gal (or ppg). This is a measure of how much proppant is added by the surface mixing equipment to a gallon of frac fluid. Another way of expressing slurry proppant concentration, which is used less often but is clearer and easier to understand, is ppa, or lbs of proppant added. This clearly illustrates the quantity of proppant being added to a gallon of clean fluid.

NEAR WELLBORE DAMAGE AND SKIN FACTOR:

Darcy's Equation for radial flow defines the rate at which oil is produced from the reservoir into the wellbore, under steady state flow conditions. In field units for an oil well, Darcy's Equation becomes:-

$$q = (.00708kh\Delta p)/ (\mu \ln(r_e/r_w)$$

where q is the downhole flow rate in bbls/day. We can see that the wellbore radius, r_w has a huge impact on the flow rate. This is easily visualized, as the closer the fluid comes to the wellbore, the more congested the flow paths become and the faster the fluid has to move. Therefore, the final few inches by the wellbore are the most critical part of the reservoir.

Unfortunately, this is also the part of the reservoir most susceptible to damage. This damage can come from a variety of sources, but most often comes from the process of drilling the well in the first place.

The major sources of formation damage are; particulates in the drilling fluid (barite, calcium carbonate etc.), filtrate invasion, whole fluid invasion, pH of drilling fluid and surfactants in the drilling fluid.

What this results in, is a region around the wellbore of reduced permeability, as illustrated in figure given below.

This reduction in permeability around the wellbore is generally referred to as the Skin, which was first rationalized by van Everdingen and Hurst (1949). The skin factor, S, is a variable that is used to describe the difference between the ideal production and the actual production through the damaged area. Generally, the skin is measured using a pressure build up test. The API has defined the skin factor for an oil well as follows:-

$$S = 1.151 ((P_{1hr} - P_{wf})/m - \log 10\ k/\Phi\mu c r_w^2 + 3.23)$$

where P_{wf} is the bottom hole stabilized flowing pressure (psi), P_{1hr} is the bottom hole pressure after one hour of static pressure build up (psi), k is the formation permeability, m is the slope of the graph of P against log10[(t + Δt)/Δt] (in psi per log10 cycle), f is the porosity (fraction), m is the fluid viscosity (cp), c is the average reservoir compressibility (psi-1) and r_w is the wellbore radius (feet).

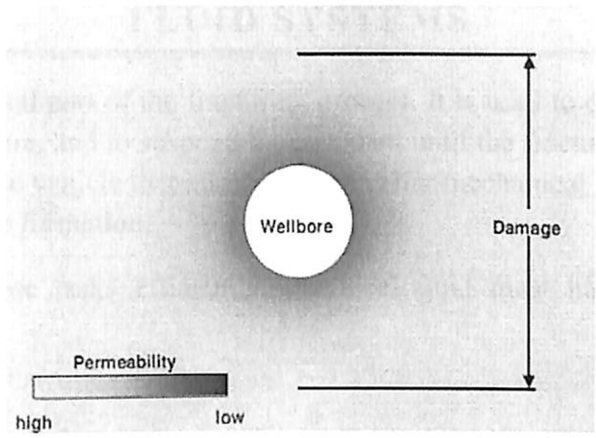


ILLUSTRATION OF REDUCTION IN PERMEABILITY
AROUND THE WELLBORE

To help matters, m can be found from the following (in field units):-

$$m = 162.6\ q\ \mu / k\ h$$

Note that both q and m are at bottom hole conditions. A completely undamaged reservoir will have a skin factor of zero. Damaged reservoirs will have skins in the ranging from 0 to 50 or even higher. Under certain circumstances, stimulation can result in a negative skin factor, which means that the well is producing more than predicted by ideal Darcy flow.

Once the skin factor has been obtained, it can be used in Darcy's Equation to give the modified flow from a skin damaged reservoir:-

$$q = 0.00708\ k\ h\ \Delta P/\mu\ [\ln (re/rw) + S]$$

This means that as S increases, flow rate decreases, and vice versa.

\

The fracturing fluid is a vital part of the fracturing process. It is used to create the fracture, to carry the proppant into the fracture, and to suspend the proppant until the fracture closes. On a more basic level, the fluid system is the vehicle that allows us to transfer mechanical energy (in the frac pumps) into work performed on the formation.

In order to carry out these tasks efficiently, the ideal fluid must have a combination of the following properties:

i) Low cost.

ii) Ease of use.

iii) Low tubing friction pressure.

iv) High viscosity in the fracture, to suspend the proppant.

v) Low viscosity after the treatment, to allow easy recovery.

vi) Compatibility with the formation, the reservoir fluids and the proppant.

vii) Safe to use.

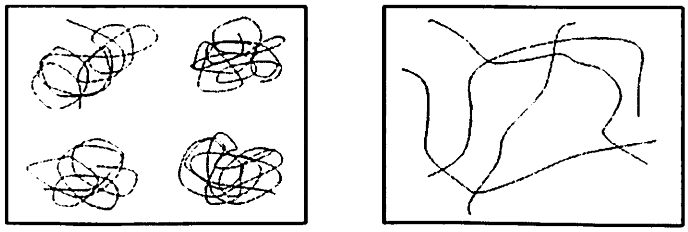
viii) Environmentally friendly.

Some of these properties are not easy to combine in the same fluid. Usually, the process of selecting a fracturing fluid is a trade off. It is up to the Engineers to decide which properties are most important and which properties can be sacrificed. In order to make this choice easier, there are a number of fluid systems available for fracturing.

WATER-BASED LINEAR SYSTEMS

The first fracturing fluid, used in Kansas in 1947, was gasoline gelled with war surplus napalm. Obviously this was a highly dangerous fluid, and it wasn't long before water based systems were available. The first of these systems used starch as the gelling agent, but by the early 1960's guar was introduced and soon became the most common polymer for fracturing. Today, polymers derived from the guar bean are used in most fracturing treatments - the other main source of polymers being cellulose and its derivatives.

Before the dry polymer is added to the water, the individual molecules are tightly curled up on themselves. As the polymer molecule hydrates in water, it straightens out – which is why these fluids are referred to as linear gels – as illustrated in Figure given below:-



A B

Hydration of polymer gels in water. 'A' shows a polymer molecule before hydration in water, whilst 'B' shows a polymer molecule after hydration in water

It is these long, linear molecules that produce the increase in viscosity. However, it should be remembered that this hydration only occurs at a specific pH range. Outside this range, the hydration rate can be very slow and sometimes almost non-existent. Different polymers have different pH ranges, and buffers may have to be used to make the polymer hydrate. If a polymer that hydrates at a neutral pH is added to water, it may start to hydrate very rapidly. This leads to the formation of "clumps" of non-hydrated polymer, surrounded by partially hydrated polymer, surrounded in turn by hydrated polymer. These are known as fish-eyes and are a sign that the gel has been poorly mixed.

Several techniques can be employed to prevent the formation of fish-eyes.

- Buffer the water so that the pH will prevent hydration. Once the polymer powder is thoroughly dispersed in the water, a different buffer is used to change the pH to a point where the polymer will hydrate.
- Add the polymer through a high shear device (such as a jet mixer) to ensure that the polymer does not form clumps.
- Circulate the hydrating gel through a high shear device, such as a choke, to break up any fish eyes.
- Slurry the polymer into a hydrocarbon-based fluid (such as diesel, kerosene or even methanol). The slurry is then added to the water, allowing the polymer to disperse before it hydrates.

A combination of these methods can also be used.

Common polymers used for linear gels include:-

- Starch
- Guar
- Hydroxypropyl Guar (HPG)
- Carboxymethyl Hydroxypropyl Guar (CMHPG)
- Carboxymethyl Guar (CMG)
- Cellulose
- Hydroxyethyl Cellulose (HEC)
- Carboxymethyl Hydroxyethyl Cellulose (CMHEC)
- Xanthan
- Xanthan derivatives (e.g. Bioxan®, Xanvis®, XC Polymer® etc)

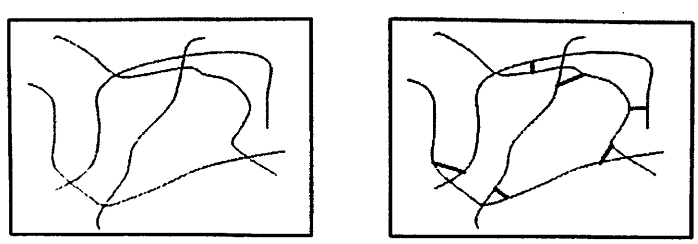
The most commonly used polymers for fracturing are Guar, HPG and CMHPG, mostly as the basis for crosslinked systems (see below). HEC is probably the most widely used polymer for linear gel fracturing, due to its popularity for fracturing low temperature, high permeability formations.

WATER-BASED CROSS LINKED SYSTEMS

The majority of hydraulic fracturing treatments are carried out using water based crosslinked gels. These systems offer the best combination of low cost, ease of use, high viscosity and ease of fluid recovery. Generally, water based crosslinked gels will be used unless there is a specific reason not to use them – they are the default option. The starting point for a crosslinked system is a linear gel. When used for crosslinked systems, linear gels are often referred to as base gels. The most commonly used linear gels are guar and its derivatives; HPG, CMG and CMHPG.

A cross linked gel, as illustrated in Figure below, consists of a number of hydrated polymer molecules, which have been joined together by the cross linking chemical. This series of chemical bonds between the polymer molecules greatly increases the viscosity of the system, sometimes by as much as 100 times.

In order for an efficient crosslink to occur, two separate things need to happen. First, the base gel needs to be buffered to a pH which will allow the cross linking chemical to work. Usually, this is at a different pH to that required for polymer hydration, so a different pH buffer has to be used. Secondly, the cross linking radical needs to be present at sufficient concentration. If both these conditions occur, the gel will experience a dramatic increase in viscosity.



A B

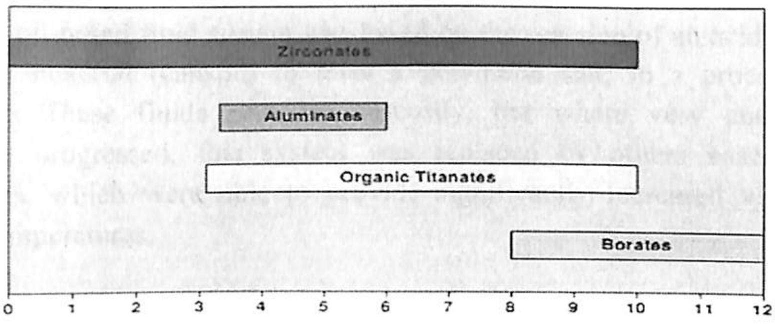
A cross linked polymer. 'A' shows the hydrated polymer prior to addition of the cross linker. 'B' shows the crosslink chemical bonds between the polymer molecules

Obviously, a fully crosslinked polymer is extremely viscous, and can result - under the wrong conditions - in a high level of fluid friction as it is pumped downhole. To counter this, it is quite common to use a delayed cross linker. A delayed cross linker can take anything up to 10 minutes before the gel is fully hydrated, depending upon the temperature, initial pH and shear that the fluid experiences. The ideal crosslink delay system would delay the onset of crosslink as long as possible, but would still have the fluid fully crosslinked by the time it reaches the perforations.

The most commonly used cross linking systems are as follows:-

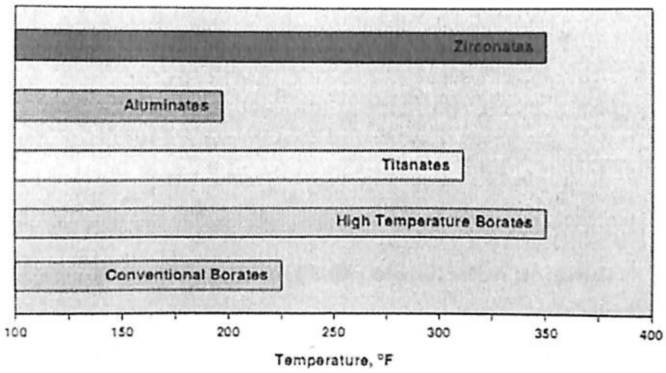
- Borates
- "Exotic" Borates

- Zirconates
- Aluminates
- Titanates



pH ranges for cross linkers

Of these, the borates and "exotic" borates are by far the most commonly used, followed by the zirconates. Figure given above illustrates the pH ranges of these cross linkers, whilst Figure given below shows their temperature ranges:-



Temperature range for cross linkers

All crosslinked gels tend to be shear thinning, which means that the apparent viscosity of the fluid decreases with shear rate. This is because the shear acts to break the crosslink bonds between the hydrated polymer molecules. Borate crosslink bonds will reconnect and produce a good quality gel after the shearing has taken place. However, zirconate bonds are much more shear sensitive and may not reconnect. Therefore, it is essential to consider the level of shear that a fluid will experience when selecting a cross linker.

OIL BASED SYSTEM

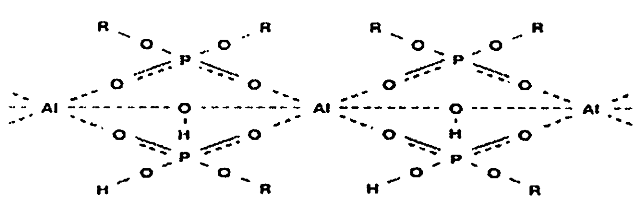
As stated previously, the very first hydraulic fracture treatment was carried out using gasoline gelled with war surplus napalm. The operation was performed on Pan American Petroleum's Klepper No 1 well, Grant county, Kansas, (part of the Hugoton gas field) in 1947. The treatment was aimed at 4 gas bearing limestone formations, at about 2500 ft. The gasoline-based fluid was selected, a it was perceived to be more compatible with the formation. This continues to be the primary reason for selecting an oil-based fluid.

For the record, the treatment on Klepper No 1 failed to produce a significant production increase, and it was decided that the "Hydrafrac" process would never compete successfully with acidizing in this type of formation.

The first widely-used oil-based fluid system was based on the reaction of an acidic material (tallow fatty acid) and basic material (caustic) to form a polymeric salt, in a process similar to the manufacture of soap. These fluids provided viscosity, but where very unstable at elevated temperatures. As time progressed, this system was replaced by others based on the use of aluminium phosphates, which were able to provide significantly increased viscosity and more stability at elevated temperatures.

In the early 70's, the aluminium phosphate systems were replaced by the aluminium ester systems. The association of aluminium and phosphate esters is illustrated in figure given below.

These systems used a combination of two products to produce the required viscosity. The relative ratio of these two products was extremely critical – so critical that it was difficult to mix these systems on the fly. Consequently, a great deal of time and effort was spent in pre-gelling tanks full of hydrocarbons, resulting in considerable spillage and waste of chemicals.



Aluminium phosphate association polymer

EMULSIONS

In general, emulsions are only rarely used in fracturing operations, but in some parts of the world they have been found to have an ideal combination of fluid loss characteristics, formation compatibility and downhole viscosity. As a result, in these areas their use is common.

Most of these systems are oil-in-water emulsions and operate in a similar fashion. Water is gelled with a standard gelling agent and held in a tank(s). During the job, water and oil are mixed together at the ratio of 2 parts oil to one part gel. An emulsifier is either pre-blended in the water phase (the gel) or added on the fly. The fluids very quickly form a brown emulsion, the viscosity of which is largely proportional to the initial viscosity of the water phase.

Some systems require an external breaker in order to destroy the emulsion and allow the fluids to be recovered. However, in most systems, the emulsion quickly falls apart after exposure to the formation.

VISCO – ELASTIC SURFACTANT FLUIDS

Visco-elastic surfactant (VES) systems are water-based fluids that employ a completely different method from all other water-based fluid systems for obtaining viscosity. They do not rely upon the hydration of a polymer. Instead, they use the unique properties of certain surfactants when mixed at certain concentrations in brine-based fluids.

In aqueous fluids, surfactants will tend to expel their lipophilic (water-repelling) tails out from the surface of the fluid. As the concentration of the surfactant increases, close packing occurs and no more surfactant molecules can expel their tails. At this point, the surfactant molecules will start to form spherical aggregates (or micelles) with the lipophilic tail facing inwards, and the hydrophilic head facing outwards. The concentration at which these micelles start to form is called the critical micellar concentration (CMC), and is often around 0.5% by volume of surfactant. The CMC will decrease as the molecular weight of the surfactant increases.

As the surfactant concentration increases further, and in the presence of a suitable counter ion (such as those produced by brines), these micelles can come together to form worm- or rod-shaped aggregates or micelles. It is these rod-shaped micelles that impart viscosity to the water.

VES fluids have some rather unique properties, as follows:-

1. VES fluids are extremely shear thinning, with the property to quickly re-heal after the shear is removed. This means that the fluids have an extremely low friction pressure whilst at the same time retaining excellent proppant transport characteristics.
2. VES fluids are very easy to mix. Simply start with the base brine and add the surfactant on the fly.
3. VES fluids can be made to be very environmentally friendly, depending upon the combination of surfactant and brine used.
4. VES fluids often require no breaker system, as micelles can be disrupted by change in pH, high temperatures, dispersion in formation waters or by contact with hydrocarbons.
5. The VES system is as formation and proppant pack friendly as the base brine used to mix it. The systems contain no polymers, and therefore produce no polymer residue. Therefore, these fluids are capable of providing zero formation damage and 100% regained proppant pack permeability.

The two main disadvantages of VES fluids are that they are relatively expensive and that they are limited by temperature. Proppant transport characteristics are rapidly lost above temperatures of +/- 230°F. Development work continues, however. Another problem with VES fluids is leakoff. Because they contain no polymers, they do not have any wall-building characteristics, and so leakoff control is entirely dependent upon the fluid's viscosity and/or additives used in the system.

ENERGIZED FRACTURING FLUIDS

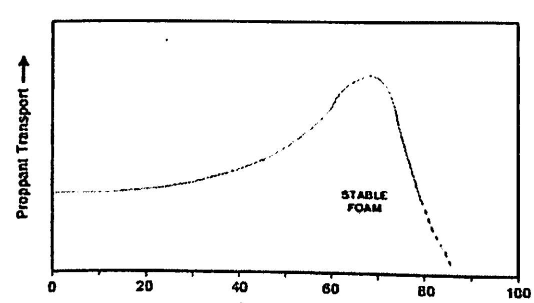
Energized fluids consist of a liquid phase – usually a water-based linear or crosslinked gel – and a gaseous phase, which is typically N2, CO2 or a combination of these. Such treatments involve large amounts of equipment and personnel. Consequently, they are relatively expensive. These treatments are also referred to a foam fracs, as foam is generally what is arriving at the formation.

Foamed fluids have several unique properties that make them advantageous under certain circumstances:-

i) Viscosity and proppant transport. Stable foams have a comparatively high viscosity and make excellent fluids for carrying and suspending proppant.
ii) Foams have very good leakoff properties. This is due to the multi-phase flow effects as the foam tries to move through the formation's porosity.
iii) Because foams are typically only 30 to 40% liquid, they are more compatible with water sensitive formations than frac systems which are 100% liquid.
iv) The extra energy stored in the fluid, coupled with the low hydrostatic head of the foam, makes fluid recovery relatively easy.

Foam Quality

The foam quality, often expressed as a percentage or just simply as a quality (i.e. "70 quality" or even "70Q") is the percentage of foam or energized fluid that is gas, at the anticipated bottom hole conditions. In order to design a foam treatment, an Engineer must have a reasonable idea of the expected bottom hole treating pressure and temperature, as the volume occupied by the gas phase will vary depending on both of these (although the temperature is much less significant than the pressure). As illustrated by figure given below, foam viscosity (and hence its ability to transport proppant) is heavily influenced by the quality. If the bottom hole pressure is significantly less than anticipated, the foam quality will be too high, and the gas phase will expand to make a mist, rather than foam.



Proppant transport as a function of foam quality. This graph is a combination of the work performed by several individuals and organisations. It is intended as a qualitative illustration of the effect foam quality has on the ability of the fracturing foam to transport and suspend proppant

Gas assisted fluids use lower gas quality (typically 20 to 40%) than foamed fluids. The main purpose of the gas phase is to reduce hydrostatic head and hence aid fluid recovery. In such treatments, the proppant transport and fluid leakoff properties for a fully foamed fluid system are not required.

Proppant Concentration

Because proppant is added to the liquid phase of the foamed frac fluid, there is a limit to the overall proppant concentration that can be achieved downhole. Because it is not possible to blend and pump proppant at more than 18 or 19 ppg in the liquid phase, by the time the liquid phase has been mixed with the gaseous phase, the overall proppant concentration has been reduced to 7 or 8 ppg. For this reason, it is not possible to place the very high proppant concentrations required for fracturing high permeability formations. This means that foam fracturing is limited to medium and low permeability reservoirs, for skin bypass fracturing (although the extra cost can defeat the low cost objectives of this type of treatment) and for coal bed methane fracturing.

Constant Internal Phase vs. Constant External Phase

Foams can be thought of as being a multi-phase fluid, with a gas-internal phase, and a liquid external phase. The difficulty comes in deciding whether or not the proppant is part of internal phase or the external phase.

The traditional method of modeling foams and designing treatment schedules uses the constant external phase method. This assumes that the proppant is part of the external phase. It is easier to operate on location, as both the slurry rate and the gas rate remain constant. However, under constant external phase, the actual fraction of the foam that is liquid can be severely reduced as higher proppant concentrations are reached. Obviously, the proppant has no properties that act to hold the foam together, so foams can become very unstable as the proppant concentration increases.

The modern way of modeling foam is to use the constant internal phase method. This models the proppant as being part of the gas phase. Therefore, in order to keep foam quality constant, the gas rate has to go down as the proppant concentration rises, and then increase rapidly as the treatment goes to flush. This method is harder operationally, but provides much more stable foam.

Foam Stability

The stability of foam is its ability to remain as foam, rather than separating out into two or even three phases. Ideally, the fluid should remain as foam long enough for the fluid to be recovered as foam after the treatment. Obviously, temperature and fluid contamination will act to reduce foam stability. There are three main methods for maximizing foam stability:-

i) Mixing the liquid and gas phases at high shear, such as with a foam generator, or by passing the mixed phases through a high shear device, such as a choke. The greater the shear that the foam experiences, the more stable it becomes. High shear acts to reduce the average size of the gas bubbles, which in turn makes it harder for them to separate out.
ii) Crosslinking the fracturing fluid after the foam has been formed. By using a delayed crosslinker, the onset of crosslink can be timed to take place after the foam has been generated, so that the gas bubbles are literally crosslinked into position.

iii) Foaming agents. These surfactants act to increase the surface tension of a material, so that the gas bubbles are much more stable.

Often a combination of these methods is used.

Foam Viscosity

The viscosity, proppant transport characteristics, fluid leakoff and stability of the foam are all influenced by the same foam characteristics - the liquid phase viscosity, the average gas bubble size, the foam quality and the surface tension properties of the liquid phase. All of these are affected by temperature and two of these are significantly affected by pressure. This means that calculating the viscosity – and hence the friction pressure and fluid leakoff – of the foam is very difficult.

Consequently, calculated bottom hole treating pressures for foam fracs are extremely unreliable and should not be used for analysis unless there is absolutely no alternative whatsoever. The results from such an analysis should be considered as educated guesswork only.

N_2 Foam Fracs

N_2 foamed fracs are the most straightforward of all the types of energized fluid fracs performed. Nitrogen is stored as a cryogenic liquid, in specialized, highly insulated tanks on location. Prior to the treatments, each tank uses a heat exchanger to vaporize a small amount of the liquid into gas. This has the effect of pressuring up the tank, so that liquid nitrogen is forced from the tank to the N_2 pumpers.

Before liquid N_2 can be pumped, the pump itself has to be cooled down. This is done by flowing liquid N_2 though the pump and out of a vent. Initially gas will bleed out if the vent. Eventually, as the unit cools down, liquid will be seen coming out of the vent, indicating to the operator that the unit is now ready to pump. Therefore, when designing N_2 foam fracs, sufficient liquid nitrogen should be on location for cooling the N_2 pumpers down at least 3 times (once for the minifrac, once for the main treatment and one spare).

It is much easier to convert a liquid from low to high pressure, than it is to convert a gas from low to high pressure. Consequently, the N_2 pumpers will be working on liquid N_2 that is stored and pumped at around –320°F. This means that specialized equipment is required for pumping this cryogenic liquid. These pumpers also include a vaporizer, which will heat the high pressure liquid and convert it into a gas (for this reason, N_2 pumpers are often referred to as "converters"). These vapourisers can be diesel fired or run from the engine coolant. As N_2 is chemically inert, there are no limitations on the fluid systems it can be used with.

CO2 Foam Fracs

CO_2 has a number of properties that make its use significantly different from N_2. To start with, liquid CO_2 is stored at –20°F. The much higher temperature means that the liquid can be pumped with a standard frac pumper (provided they have been specially prepared). It also means that the liquid CO_2 does not have to be converted into a gas before it is mixed with the liquid phase – this will happen automatically as the CO_2 heats up.

The second major property difference of CO_2 is its tendency to form a solid ("dry ice") if stored or pumped under the wrong conditions. Obviously, this must be avoided. Dry ice will only form below +/- 80 psi. So at every stage, the liquid CO_2 is kept well above this pressure. Typically, CO_2 is stored at between 150 to 300 psi. There are several different methods for pumping the liquid CO_2 from the tanks to the pumpers. One method involves forcing it out with N_2 pressure applied above the fluid level in the CO_2 tank. Another method employs specialised boost pumps. Yet another method employs a combination of these two systems.

The third major difference is that unlike N_2, CO_2 is not chemically inert. Specifically, on contact with water based fluids, some of the CO_2 will dissolve into the water to form an acid. This has the effect of lowering the pH of the system. This means that CO_2 is not compatible with high pH fracturing fluids, such as borate crosslinked gels.

Binary Fracs

Binary Fracs involve the use of a mixture of both CO_2 and N_2 to provide the foam. They were originally developed as a method of getting around one service company's patent on CO_2 foam fracturing. Since then, the method has been extensively developed and is now the preferred method of foam fracturing for many operating companies.

Binary fracs are the most complicated stimulation operations performed, requiring the use of no less than three service supervisors (one for the CO_2, one for the N_2 and one for the liquid phase, who is in overall control). Consequently, these are relatively uncommon.

Poly CO_2

Poly CO_2 is a highly specialised fluid developed by Nowsco in Canada. In this fluid, a specialised additive is mixed into the water-based liquid phase, which causes the water-based gel and the liquid CO_2 to form an emulsion, rather than foam. The emulsion is not particularly stable, and will break down after the fluid contacts the formation.

This fluid system has only ever been used in low temperature applications, and it is unclear as to whether the stimulation benefits come from the placing of proppant, or from the thermal shock experienced by the formation. However, in certain formations it has proved to be highly successful.

ADDITIVES

There are an enormous number of additives used in the preparation of the various types of fracturing fluids, and an exhaustive list is beyond the scope of this manual. However, below is a description of the general types of additive, together with the most commonly used examples.

Gelling Agents

Water-based gelling agents are designed to increase the viscosity of water. This water can be fresh (rarely), 2% KCl, 3% NH_4Cl, seawater or any of a myriad of different kinds of brines. Nearly all the gelling agents are some kind of polymer. A wide range is available, depending upon hydration pH, temperature stability and polymer residue:-

Guar	**GW-4, GW-27**
High- yield guar	**GW-3**
Hydroxypropyl Guar (HPG)	**GW-32**
Carboxymethyl Hydroxypropyl Guar (CMHPG)	**GW-38**
Carboxymethyl Guar (CMG)	**GW-45**
Hydroxyethyl Cellulose (HEC)	**GW-21, GW-24L, AG-21R**
Carboxymethyl Hydroxyethyl Cellulose (CMHEC)	**GW-28**
Xanthan	**GW-22, GW-22L, GW-37**
Polysaccharide	**GW-23**

Oil-based gelling agents are designed to increase the viscosity of oil-based fluids. These gelling agents work on a wide variety of hydrocarbons, but are primarily designed for diesel and kerosene. Any other hydrocarbon fluid should be tested prior to application.

GO-64	Gelling agent for Super Rheo Gel
GM-55	Gelling agent for Metho Frac XL

Crosslinkers and Complexers

Crosslinkers and complexers are designed to dramatically increase the viscosity of an already gelled fluid, so that high viscosity can be maintained for extended periods of time at high temperatures. For many fluid systems, the crosslinker is the chemical that really defines its characteristics.

Crosslinker	Borate	Titanate	Zirconate	Aluminum
Crosslinkable polymers	Guar, HPG, CMHPG	Guar, HPG, CMHPG, CMHEC†	Guar,‡ HPG,‡ CMHPG, CMHEC†	CMHPG, CMHEC
pH range	8–12	3–11	3–11	3–5
Upper temperature limit (°F)	325	325	400	150
Shear degraded	No	Yes	Yes	Yes

†Low-pH (3–5) crosslinking only
‡High-pH (7–10) crosslinking only

Characteristics of commonly used cross-linkers

Breakers

Breakers are designed to reduce the viscosity of the fracturing fluid to a minimum, so that the fluid can be easily recovered after the treatment. They are also designed to minimise polymer residues, so that damage to the proppant pack is minimized.

GBW-5, GBW-7, GBW-41L	Oxidizing breakers
GBW-23, GBW-24	Delayed oxidizers
GBW-26C	Enzyme breakers for cellulose + derivatives
GBW-12CD	Enzyme breaker for guar + derivatives
GBW-14C	Enzyme breaker for xanthan + derivatives
High Perm CRB	Encapsulated oxidizing breaker
GBO-5L, GBO-6, GBO-9L	Breakers for **Super RheoGel**

Which type of breaker is the best is currently a topic for much debate. Both of the common types of breakers have strengths and weaknesses

Selection Criterion	Oxidizers	Enzymes	Comments
Performance at high temperature	+		Oxidizers have been identified for high-temperature applications. Current enzymes have some activity up to 225°F [105°C]. Higher temperature versions will most likely be identified in the future.
Completeness of break		+	Theoretically, enzymes should have the advantage because of their catalytic nature. However, enzyme sensitivity to temperature, pH and other chemicals can significantly shorten the life-time of the enzyme. Under ideal conditions (less than approximately 180°F [80°C], pH 5–8), enzymes break the polymer into smaller fragments than oxidizers do, but there is no information in the literature to document that significant production of simple sugars results.
Duration of breaking		+	Enzymes, unless exposed to extremes of pH or temperature, react with the polymer over a more extended time period (days) than oxidizers (hours).
Fast break	+		A fast break to allow quick turnaround of the well is accomplished much better with oxidizers.
Chemical sensitivity	+	+	Enzymes are highly sensitive to pH, so control of pH within a limited range is necessary for predictable performance. Oxidizers are affected by the presence of curable-resin-coated proppants, whereas enzymes are not.

Breaker selection

Buffers

Buffers are designed to either raise the pH or lower the pH, as required.

Low pH buffers	**BF-1, BF-10L, BF-10LE**
High pH buffers	**BF-7, BF-7L, BF-8L, BF-9L, caustic soda**

Surfactants

The word Surfactant comes from the phrase SURFace ACTive AgeNT, and includes any chemical that affects the interface properties between materials. Because this covers such a wide range of materials, it is necessary to discuss this group of products in more detail. Surfactants can also be grouped according to the type of charge they possess, so that some surfactants are anionic (negative charge), some are cationic (positive charge), some are amphoteric (cationic at low pH and anionic at high pH), some are Zwitterionic (both cationic and anionic simultaneously) and some are non-ionic. Generally speaking, it is best not to mix anionic and cationic products together, as they might form viscous deposits.

Most of surfactant products are designed to leave the formation water wet. This means that the relative permeability of the formation to water has been lowered, and the relative permeability of the formation to oil has been raised. However, it is important to note the following:-

Cationic surfactants will leave sandstones oil wet and carbonates water wet
Anionic surfactants will leave sandstones water wet and carbonates oil wet.

Amphoteric surfactants can behave either way depending upon the pH. At acidic pH's (less than 7), amphoteric surfactants show cationic properties, whilst at alkaline pH's (greater than 7), they display anionic properties. At neutral pH, they behave like non-ionic surfactants.

Non-emulsifying surfactants are designed to prevent the formation of emulsions between the crude oil in the formation and the treatment fluid. All water-based treatments should have a non-emulsifying surfactant added to them, unless they are being pumped into a water injection well or dry gas reservoir with no trace of condensate.

Inflo 100, Inflo 102	Blend of cationic and nonionic
NE-13	Blend of cationic and nonionic
NE-110W	Anionic
NE-118	Nonionic
NE-940	Nonionic

Note that some non-emulsifiers will also act to break existing emulsions.

Foaming agents work by increasing the surface tension of the fluid. This helps increase foam stability. Most foaming agents also acts as detergents and dispersants.

FAW-4	Anionic
FAW-18W	Anionic
FAW-20	Anionic
FAW-21	Amphoteric
FAO-25	Nonionic – foaming agent for oil-based fluids

Note that **FAW-4, FAW-18W** and **FAW-20** will leave carbonate formations oil wet.

Low surface tension modifiers act to reduce the surface tension of the fluid. This helps the fluid penetrate into very small places, such as the pore spaces in low permeability reservoirs. These products also help the treatment fluid flow back out of the well after the treatment is finished.

Flo-Back-20, Flo-Back-30	Nonionic
Inflo-100	Blend of cationic and nonionic

Inflo-150	Nonionic

Mutual solvents will dissolve hydrocarbon based deposits and allow them to disperse water based fluids.

US-2, US-40	Nonionic
Inflo-40	Nonionic

Emulsifiers are used to deliberately create emulsions. They only should be used as part of an emulsion-based fluid system

AE-7	Cationic
E-2	Cationic

Biocides

Biocides, also known as Bactericides, are designed to kill bacteria. Any bacteria – especially sulphate reducing bacteria – will eat the polymer used in frac fluids. A colony of bacteria can reduce a tank of good quality gel into foul-smelling slick water in less than an hour. Biocides are used to prevent this. Initially, all tanks used for frac fluids should be as clean as possible. This will help reduce the risk of bacterial contamination. However, the water used to mix the gel can still contain these bacteria, especially if the climate is hot or seawater is being used. The biocide should be added either directly to the tank before the water is added, or it should be thoroughly mixed into the water prior to the addition of any polymer. Once the biocide has been added, it will quickly kill any bacteria that are present in the water.

It is recommended that a biocide is used on any treatment with involves pre-gelling the fluid.

It should be remembered that biocides are designed to prevent a colony of bacteria from developing in the first place, rather than for killing an existing colony - any gel that is suspected of being contaminated should be discarded, and its tank thoroughly cleaned. In order to break down the gel, bacteria secrete enzymes (similar enzymes to the breakers described above). These enzymes will cause a tank of gel to degrade, so that even if all the bacteria in a tank have been killed, their enzymes are still present in the tank. This is why contaminated tanks of gel need to be discarded, and not used again.

It should also be noted that in their concentrated form, biocides are very dangerous materials (after all, they are designed for killing living things) and should be handled with extreme care.

Magnacide 575
XCide 102, 207

Gel Stabilisers

Gel stabilisers are used to prolong the viscosity of crosslinked gels at high temperatures. They work by one of two methods:- they can scavenge the oxygen in the fluid; or they can chelate cations which can contribute to the degradation of the gel.

GS-1, GS-1L, GS-9
Methanol

Clay Control Additives

Clay control additives are used to prevent the swelling, migration and disintegration of clay minerals such as illite, smectite, chlorite and montmorillonite. Fresh water by itself will cause these problems. The addition of chloride ions to fresh water will prevent these problems in most formations, so that most treatments carried out with seawater do not need any additional clay stabilisers. However, exceptionally water sensitive formations may need additional protection.

KCl, NH_4Cl, NaCl etc	standard salts for brines
$CaBr_2$, $ZnBr_2$, etc brines	specialised salts for high density completion
Clay Treat 3C	KCl substitute, recommended for **Vistar**.
Clatrol	
Claymaster 5C, FSP	

Note that any salts containing calcium or magnesium should not be mixed with frac fluids, as these are incompatible with some crosslinkers. Also note that some of the synthetic claycontrol additives are cationic in nature and should not be mixed with any anionic products.

Fluid Loss Control

Fluid loss control additives can be used for two main reasons; firstly, to lower a very high matrix leak off rate; and secondly, to prevent fluid loss down natural fractures. The use of fluid loss additives is becoming less and less common, as the understanding of fluid leakoff increases. Most Engineers also believe that pumping more fluid is preferable to using additives that can potentially produce permanent damage.

Silica flour, 100 mesh sand	Used for blocking natural fractures
5% diesel	
Adomite Regain®	

The word proppant comes from the abbreviation of two words - "propping agent". Proppants are granular materials, which are placed inside the fracture in order to "prop" the fracture open as the pressure falls below closure. The conductivity of the fracture is directly related to the quantity of proppant within the fracture, the type of proppant, the producing conditions and the size of the proppant grains.

The purpose of hydraulic fracturing is to place the right amount of the right kind of proppant in the right place. When this is done correctly, the well is effectively stimulated.

PROPPANT PACK PERMEABILITY AND FRACTURE CONDUCTIVITY

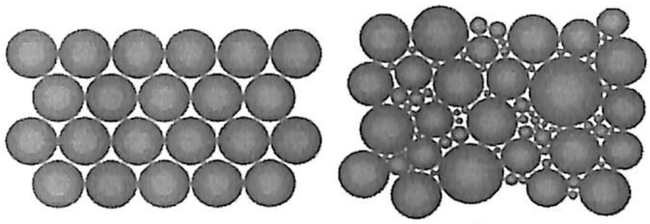
One of the major factors affecting post-treatment well performance is the fracture conductivity. This is the product of the proppant pack permeability and the width of the fracture. In other words, the fracture conductivity is a function of the type of material holding the fracture open and the amount of this material within the fracture.

The permeability of the proppant pack is controlled by several factors:-

i) Proppant Substrate. The material that the proppant is made from obviously has a big effect on the permeability of the proppant pack. Some materials are stronger than others and are better able to withstand the enormous forces trying to crush the proppant as the fracture closes. The weaker the material, the more the proppant grain will deform. Proppant deformation reduces the porosity of the pack and reduces the overall fracture width. The more brittle the proppant is, the more likely it is that the proppant will produce fines as the grains are pushed together in a series of point to point contacts. Any fines will significantly reduce the proppant pack permeability.

ii) Proppant Grain Size Distribution. A normal sedimentary formation has a wide variety of grain sizes, depending upon how well "sorted" the individual rock grains are. In general, any sandstone will be a mixture of small, medium and large grains. The mixture of grain sizes acts to reduce the formation's permeability and porosity, as the smaller grains will occupy the pore spaces between the larger grains and will also tend to plug up the pore throats. However, if a set of particles are of almost identical size, then there will be no fines to block up the pore spaces and pore throats, so that the porosity (and hence the permeability) are maximised.

This is why proppants are generally produced within a specific grain size distribution. This uniformity of grain size is one of the main reasons why proppant is usually several orders of magnitude more permeable than the formation, and also one of the main reasons why so much effort is spent in ensuring this uniformity of size. This is illustrated in figure below;



The effect of uniform and natural grain size distribution on porosity

Proppants are supplied within a specific grain size range. This grain size refers to the size of sieve used to sort the proppant. For instance, 20/40 size means that the vast majority of the proppant will fit through a size 20 sieve (20 holes per square inch), but will not fit through a size 40 sieve (40 holes per square inch). This is sometimes confusing, as larger grain sizes correspond to smaller mesh numbers. Common proppant sizes are 8/12, 12/20, 16/30, 20/40 and 40/60, although theoretically any combination of sizes can be produced.

iii) Average Proppant Grain Size. Generally, the larger the average proppant grain size is, the higher the permeability of the proppant (provided the grain size distribution is reasonably uniform). This is because larger grains produce larger pore spaces and pore throats, allowing an increased flow rate for a similar porosity. However, the larger grains are more susceptible to producing permeability reducing fines than are the smaller grain sizes. This is because larger grains distribute the closure pressure across fewer grain-to-grain points of contact and so the point contact loads tend to be greater. This is illustrated in figure below;

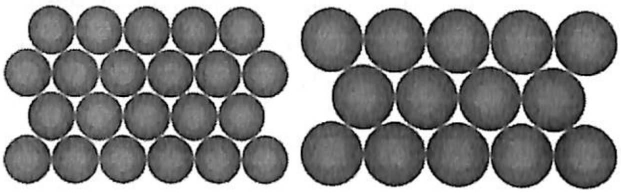


Diagram illustrating how larger grains have larger pore spaces and hence greater permeability

iv) Sphericity and Roundness. These quantities define how spherical the proppant grains are and how many sudden, sharp edges the grains have. Obviously, the smoother and more spherical the proppant grain is, the higher the pack permeability. There are standard API procedures for checking these quantities, but unfortunately they rely on some subjective analysis. Consequently, it is often difficult to see a clear trend between one proppant type and another. However, in general, artificial proppants will have better sphericity and roundness than naturally occurring types. This is illustrated in figure below;

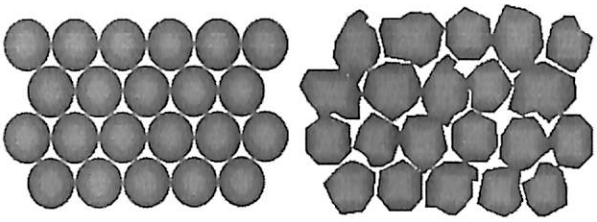
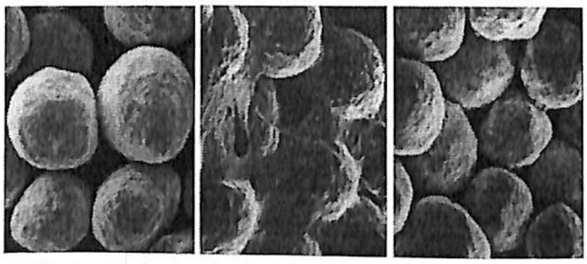


Diagram illustrating the difference between a proppant with good sphericity an roundness (left), and a proppant with poor sphericity and roundness (right)

Coarse, angular grains also tend to produce more fines, as corners and edges tend to get broken off as compressive stress is applied. Therefore, proppants with good sphericity and roundness also tend to retain greater permeability at high stresses. In addition, because proppant with low sphericity and roundness will produce a more convoluted flow path for the produced fluids, non-Darcy pressure losses tend to be greater in these materials (see Section 10.9), leading to decreased effective proppant pack permeability.

v) Frac Fluid Quality. The amount of residue left by the fracturing fluid can also have a big influence on the permeability of the proppant pack. In order to assess the effect of these fluids, a quantity called Regained Permeability is measured. Put simply, a sample of the proppant is put into a load sell and is subjected to a closure pressure, at an elevated temperature. A standard, non-damaging fluid is then flowed through the test cell. By analysing the pressure drop and flow rate, the permeability of the pack can be calculated. Next, the frac fluid is flowed through the test cell, and allowed to remain there for a specific time, during which it is designed to break. Once the fluid has broken, the permeability of the pack is measured again, by the same method as before. The two permeabilities are compared and the result (the regained permeability) is given as the percentage of the original permeability that remains after the test.

Figure below illustrates the difference between fluids with a high and low regained permeability;



Three SEM micrographs showing the effects of frac fluid residue. The micrograph on the left shows undamaged proppant before the addition of the frac fluid. The center micrograph shows the residue left by a poorly designed cross linked system. The final micrograph shows the same proppant pack after an enzyme breaker has been used

Proppant packs can lose significant proportions of their permeability to fluid damage. Cheap, poorly designed fluids can cause regained permeabilities to be as low as only 30% or even less, whereas the state-of-the-art fluids can produce values in excess of 90%.

vi) Closure Stress. As the proppant is crushed by the closure of the formation, it will start to produce fines. As discussed above, these fines will reduce the permeability of the pack. The stronger the proppant, the fewer fines are produced - nevertheless, all proppant types experience a decrease in permeability as closure stress increases, to a greater or lesser extent. In addition, most proppants also have a "maximum" stress, above which whole-scale disintegration of the proppant substrate starts to occur, rather than simple fines production. At this point, pack permeability falls dramatically.

It should be noted that the reservoir pressure has an influence on the closure stress experienced by the proppant. The relationship between reservoir pressure and closure pressure is dependent upon a number of factors - there are circumstances under which a decrease in reservoir pressure can result in an increase in closure stress. Additionally, there can be localised areas of low reservoir pressure (such as near the wellbore during drawdown) where once again the proppant experiences higher closure pressure. This potential increase in stress with the life of the well must be allowed for when selecting a proppant.

vii) Non-Darcy Flow. As the flow rate through the proppant pack increases, the pressure drop will increase at a rate faster than that predicted by Darcy's law. This is due to the effects of inertial energy loses, as the fluid rapidly changes direction as it moves through the pore spaces. As the fluid velocity increases, the pressure drop due to inertial flow effects increases with the square of the velocity. So at low flow rates, (such as in a reservoir rock), non-Darcy effects can safely be ignored, whilst at high rates (such as in a proppant pack), the effective proppant permeability has to be reduced to reflect this effect. The phenomenon is particularly significant in high rate gas completions.

viii) Multi-Phase Flow. Multi-phase flow has a similar effect upon proppant pack permeability as it does on formation permeability. It reduces it, by an amount that is dependent upon the absolute permeability, and the relative saturation of each phase. As it is very rare for a reservoir to produce a single phase (with the exception of some gas reservoirs), it is also very rare for proppant to conduct only a single phase. Therefore, the actual effective permeability of the proppant pack may be significantly less than the published data, which is generally produced for single-phase flow only (although this situation is improving).

PROPPANT SELECTION

There are a substantial number of variables that must be taken into account when selecting proppant. However, in many cases the selection process has been simplified.

All proppant suppliers and manufactures publish data for pack permeability against closure stress, for all their proppant types and grain size distributions. Provided the closure stress is known (taking into account any subsequent loss in reservoir pressure), the absolute permeability of the proppant pack can be easily found. This eliminates the need for the Frac Engineer to hold data on sphericity, roundness, crush resistance, grain size distribution, substrate material etc. Simply look up the proppant you are interested in, and see what the permeability is for a given closure stress.

Most fracture simulators already have this data for most major proppant types. This allows the simulator to predict the fracture conductivity for most given proppant/closure stress combinations. Usually, there is also a "proppant damage factor", which allows the user to simulate the regained permeability effects of the fracturing fluids.

Some - but not all - fracture simulators will also model the effects of non-Darcy flow, showing a decrease in effective permeability as production rate rises.

However, no current fracture simulators allow for the effects of multi-phase flow. Data on this has been published by a few sources, the most notable of these being the Stim-Lab Consortium's PredictK software and Carboceramics' FracFlow proppant permeability simulator.

Table below gives guidelines as the maximum closure stress each of the major proppant types can withstand, before substrate failure begins to occur. Obviously, these limits are very generalised, and are highly dependent upon factors such as grain size and the quality of the manufacturing process and/or source of sand.

Type	**Maximum Closure Stress, psi**	**Product Example**
Frac Sand	5,000	*Brady, Ottawa, Colorado*
Low Density Ceramics	9,000	*CarboEconoprop, CarboLite ValueProp*
Intermediate Density Ceramics	12,000	*CarboProp, InterProp*
Sintered Bauxite	14,000 *Carbo*	*HSP, Bauxite*

Generalised maximum closure stresses for the main proppant types.

Important Note

The quality of the proppant, and the subsequent conductivity of the fracture, has a bigger effect on post treatment production than virtually anything else under the Frac Engineer's control. In most cases, an economy made on proppant selection is a false economy. For instance, although low-density ceramics cost two to three times as much as frac sand, they have four to five times the pack permeability - even at low closure stresses - due to their high sphericity and roundness.

Resin-Coated Proppant

Many operating companies prefer to use resin-coated proppant or sand for some or all of their fracture treatments. There are many different types of resin coat and the manufacturers are continually improving and updating their products. Therefore, it is advised to consult the manufacturer's specifications for details of any specific product. However, broadly speaking, resin-coated proppant can be divided into two main categories as follows:-

<u>Curable</u>

Curable resin-coated sand or proppant is coated with a resin designed to harden when exposed to temperature and/or closure stress. This allows the resin-coated grains to adhere to each other, and hence dramatically reduce the effects of proppant flowback. At low temperatures, an activator is added to the fracturing fluid in order to improve the adhesion.

Tempered or Pre-Cured

Tempered or Pre-cured resin coatings are harder than curable resin coats. They rely more on closure pressure than temperature in order to make the sand or proppant grains adhere to each other. These resin-coatings also have a secondary effect. Because the resin coat acts to reduce thee localised contact stresses between proppant or sand grains and because any fines produced by this process are kept within the resin coat, these materials tend to have a higher closure pressure resistance than the same material without the resin coat. This means that they retain permeability under higher crush loadings and so can – for instance – extend the range over which a cheaper material, such as frac sand, can be used.

Resin coated proppant or sand has a number of significant drawbacks, however:-

1. Cost. Coating the grains with resin can substantially increase the cost of the proppant, especially when coatings designed for high pressure and temperature are used.
2. Resin coats tend to affect the properties of the fracturing fluid. The exact variation in properties depends upon the pH of the frac fluid and the type of resin coat. However, it is common for resin-coated proppant to make frac fluids much harder to break. It is recommended that when resin-coated proppant or frac sand is being used, testing is performed on the frac fluids with the proppant in the fluid.
3. Resin coat tail-in. Many operators like to save money on a treatment by only using resin coated sand or proppant for the last 20 or 30% of the treatment. The theory being that only the part of the proppant close to the wellbore actually needs to adhere together to prevent proppant flowback. However, due to the effects of proppant convection and settling , there is no guarantee that the proppant pumped last in the treatment will be the proppant that ends up right by the wellbore. In fact, the only way to guarantee this is to pump 100% resin coated material.

PREDICTING PRODUCTION INCREASE

Being able to accurately predict a production increase from a formation is an important part of the process of designing a frac treatment. All treatments have to be economically justifiable, before approval by the operating company. In order to be able to produce an economic justification, the Engineer must have a reasonable idea of what the post fracture production increase will be. Moreover, this prediction must be reliable, as the Engineer will have a hard time justifying subsequent treatments, if previous justifications have proved to be inaccurate.

In order to be able to produce an accurate prediction of the increase in production, the Engineer needs accurate pre-treatment production data. Items like permeability, skin factor, BHP and downhole producing rate are all critical. If accurate values for items such as these cannot be obtained, then the subsequent predicted production increase will also be inaccurate.

Nevertheless, because of the uncertainties associated with most of the data used in the analyses below, any estimate of post fracture production remains just that – an estimate. The Frac Engineer must make this clear to any customer. As a result, it is often more reliable to base post-treatment production estimate on the results of offset wells, if any are available.

STEADY STATE PRODUCTION INCREASE

Steady state production is when all reservoir parameters remain unchanged during the production process. Items such as radial extent and reservoir pressure are fixed. Most of the time this does not exist, and the reservoir is at least in a pseudo-steady state. Consequently, production increases based on steady state are an approximation only.

However, they are often useful as a "first look", "back-of-the-envelope" calculation, to quickly see if a fracture is viable or not.

Darcy's Equation (which is for steady state flow only) can be expressed as follows for a skin damaged reservoir:-

$$q = 0.00708\ k\ h\ \Delta P/\mu\ \ln[r_e/(r_w e^{-S})] \qquad \text{(A)}$$

where q is the downhole producing rate in bpd, k is the effective reservoir permeability in md, h is the net height of the formation in ft, ΔP is the pressure differential between the edge of the reservoir and the wellbore (the drawdown) in psi, μ is the downhole viscosity of the reservoir fluid in cp, r_e is the radial extent of the reservoir, r_w is the wellbore radius and S is the skin factor (dimensionless). Note that r_e and r_w should always have the same units, usually either feet or inches.

To provide a fair comparison between productions at different times, which may be at varying drawdown, the productivity index, J, is usually used instead of the production rate. The units of productivity index (or PI) are usually bbls/day/psi, or bpd/psi.

$$J = 0.00708\ k\ h/\mu\ \ln[r_e/(r_w e^{-S})] \qquad \text{(B)}$$

To avoid confusion, the symbol J will be used to signify the PI from a real, damaged reservoir. J_o is used to represent the PI from an undamaged reservoir and J_f for the fractured reservoir.

In Darcy's Equation, the term kh is often referred to as the permeability-thickness, or conductivity. This equates to the fracture conductivity, F_c, of the propped fracture. By replacing the term kh with F_c we can obtain an expression for the PI of the fractured reservoir:-

$$J_f = 0.00708\ F_c / \mu\ \ln[r_e/r_w] \qquad \text{(C)}$$

Equation (C) should be used with some caution. This is a steady state approximation to a situation that in reality is far from steady state. The Equation no longer uses the skin factor term, as it is assumed that the fracture has completely bypassed the skin, rendering it irrelevant. This Equation also assumes that all production into the wellbore comes via the fracture. This is a valid assumption for fractures with a very high C_{fD}, but becomes less and less accurate as the contrast between the fracture and reservoir conductivity becomes lower. Indeed, if the fracture conductivity is too low, this method may actually predict a production decrease – something that is theoretically impossible, unless the fluid or proppant somehow damages the formation. This Equation also assumes that the formation has no difficulty delivering reservoir fluids to the fracture – the Equation is independent of fracture length.

Nevertheless, Equation (C), still provides a "first guess" to see how viable a fracture treatment is. However, it is less accurate for low permeability reservoirs and for fractures which relatively low fracture conductivity.

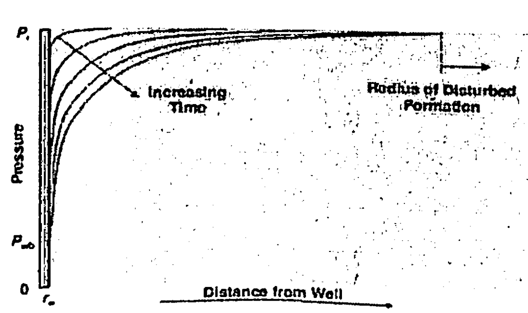
The "folds of Increase" (J_f/J) can be calculated, by dividing Equation (C) by Equation (B), which gives the following:-

$$(J_f/J) = (F_c/kh)\ (\ln[r_e/(r_w e^{-S})]/\ln(r_e/r_w)) \qquad \text{(D)}$$

Another way of getting a "quick look" at potential post-treatment production is simply to use a skin factor of -5 in Equation (A).

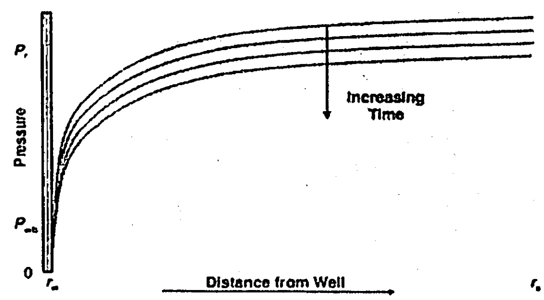
PSEUDO-STEADY STATE PRODUCTION INCREASE

Pseudo-steady state flow is when the reservoir has been producing for a sufficient period of time, so that the effects of reservoir boundary can be felt. In practical terms, this means that the reservoir has an outer boundary.



Transient production. The red lines illustrate the variation of pressure wit distance from the wellbore, as time increases. The radius of the disturbed formation is continually increasing

As the well is produced, the radius from the wellbore at which the reservoir has been disturbed by production increases at a rate proportional to the square root of the producing time. During this period, flow into the wellbore can be described as transient, as the effective radial extent of the reservoir is continually increasing. However, at some point the area of formation disturbed by the production from the well will hit an outer boundary. At this point, the radial extent of the reservoir ceases to expand, and the reservoir pressure starts to fall. At this point, the reservoir switches from transient to pseudo-steady state. The difference between transient and pseudo-steady state is illustrated in Figures above and below.



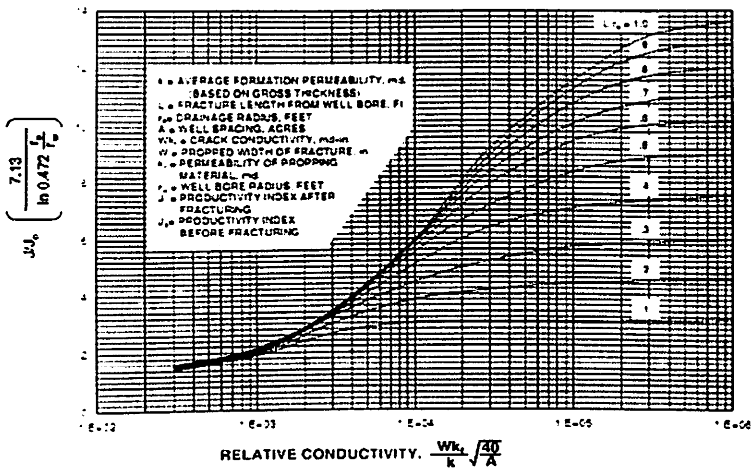
Pseudo-steady state production. The radius of the disturbed formation has reached the reservoir boundary, r_e, and now the reservoir pressure is decreasing

Most reservoirs will spend the majority of their producing lives in pseudo-steady state production.

McGuire and Sikora

The best known method for predicting production increase during pseudo-steady state production was developed in 1960 by McGuire and Sikora. This work was based on earlier work carried out on electrical circuits by Dyes, Kemp and Caudle. Basically, they used a series of resistors and capacitors to represent the reservoir – resistors to represent permeability (the lower the resistance the higher the permeability), capacitors to represent the porosity or storage capacity of the reservoir, voltage to represent pressure and current to represent flow rate.

These experimentally-derived curves, shown in figure below, define for a given dimensionless fracture length (L/r_e) and a given fracture relative conductivity, the dimensionless production increase that can be expected. McGuire and Sikora used L for fracture half length, instead of the usual x_f.



McGuire and Sikora curves

$$\text{Dimensionless fracture half length} = L/r_e \qquad \text{(E)}$$

Where L is the fracture half-length (x_f normally) in feet and r_e is the reservoir drainage radius or radial extent, also in feet.

$$\text{Dimensionless production increase} = (J/J_o)\,(7.13/[\ln 0.472(r_e/r_w)]) \qquad \text{(F)}$$

Where J is the pre-frac productivity index, J_o is the post-frac productivity index (J_f normally) and r_w is the wellbore radius.

McGuire and Sikora is an approximation based on the limits of the experimentation they conducted. The main assumption is that the fracture is significantly more conductive than the formation, so that the main rate limiting variable is the fracture half length. Vertical fluid flow is assumed to be negligible, fluids are assumed to be incompressible and in single-phase flow and skin factor is assumed to be zero. However, it is often relatively easy to find the production increase if the skin was reduced to zero. The McGuire-Sikora production increase can simply be added to this.

Skin Bypass Fracs

Rae et al presented a simple method for predicting the production increase from a skin bypass frac. It combines elements of the McGuire-Sikora and Prats methods and allows for the existence of a skin factor:-

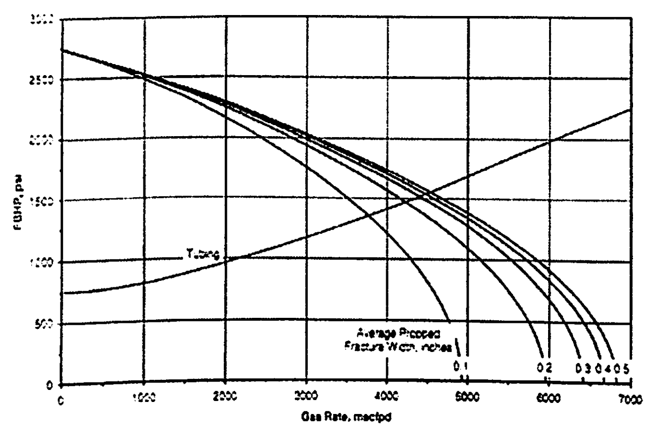
$$(J_f/J) = \ln(r_e/r_w\, e^{-S}) / \ln[4/(F_{cd}.x_{fD})] \qquad \text{(G)}$$

This method is valid for fracture with a C_{fD} greater than 1 – i.e., more conductive than the formation.

NODAL ANALYSIS

The most modern method for predicting production increase is the Nodal Analysis programme. These simulators work by analysing the flow from the reservoir at a node, which can be down hole at the "sand face", at the wellhead or at some distance from the wellhead in a separator. By defining the flowing conditions at this node, the software can then calculate back to the flow rate from the reservoir.

Nodal analysis can be used to produce inflow performance relationship (IPR) curves, which relate the ability of the reservoir to deliver fluids, with the ability of the completion to carry fluids out of the reservoir. These curves are particularly useful for oil wells with a GOR (i.e. real wells and not "black oil" approximations), gas wells and wells producing at significant water cuts, where the ability of the completion to carry the fluids is not always easy or straightforward to calculate. Figure given below shows an example for a gas well with a fracture of varying average propped fracture width.



Nodal analysis IPR curves for a gas well with a fracture of varying propped fracture width.

With reference to the example in figure above, note the following points:-

- The blue curves represent five different production scenarios. In this case, each curve represents varying propped fracture width. However, they could just as easily be varying skin factor, permeability or water cut. This ability to test the sensitivity of the system to varying producing scenarios makes nodal analysis very powerful.

- The blue curves are the inflow curves. For these, the node is fixed at bottom hole (or the "sand face"). Each of these curves represents the inflow into the well from the formation for hydrocarbons at various FBHP's (flowing bottom hole pressures). The drawdown is the difference between the reservoir pressure and the FBHP, so the smaller the FHBP, the greater the drawdown.

- The red curve is the outflow or tubing curve. This represents the ability of the completion to carry the hydrocarbons out from the well. In this case, the node is fixed at the wellhead. A set of wellhead conditions are specified, and then the software calculates (for a fixed

FWHP – flowing wellhead pressure – and surface temperature) what the bottom hole pressure must be for a variety of different flow rates.

- The point at which the red curve and the blue curve cross represents the point at which the two sets of conditions coincide. Therefore, this is the rate and FBHP at which the well will produce. For instance, in figure above, for a frac width of 0.2 inches, the well will flow at 4250 mscfpd at a FBHP of +/- 1450 psi.

Most nodal analysis programmes allow the user to produce the well through a propped hydraulic fracture of varying geometry. This is very useful to the Frac Engineer, who may well end up spending more time with the nodal analysis than with the fracture simulator. When using nodal analysis to predict production increase, the following steps should be followed:-

1. Get production data from the well. If the well is new, get production data from an offset. If no offsets are available, use the well test data.

2. History match the production data with the nodal analysis (and without a fracture being present). Vary items such as skin factor, permeability and reservoir pressure to make the nodal analysis production match the historical production data. The nodal analysis production simulator is now tuned to the real data.

3. Introduce a fracture. Vary characteristics such as fracture length and fracture conductivity (or average propped width) to produce the biggest possible increase in production.

4. Be aware of what is achievable and what is efficient. For instance, the nodal analysis may indicate that doubling the fracture length gives an extra 50% production. What it does not tell you is that doubling the fracture length means at least 4 times as much proppant, 8 times as much fluid and a corresponding increase in equipment. Such an increase in job size may not be practical and could well be uneconomic.

5. Once the optimum fracture geometry has been obtained, go to the fracture simulator and design a treatment to make a fracture of these dimensions. Often, it is at this point that the Engineer finds out what is realistically achievable and so the final design may be the product of several alternating runs on both the nodal analysis and the fracture simulator.

Of all the things under our control, the position, number, size and phasing of the perforation has the single biggest influence on the effectiveness of the hydraulic fracture treatment. Man times this is outside of the control of the Frac Engineer, as a high proportion of treatments ar carried out on existing wells that have already been perforated. However, if a well or a interval is new, the Frac Engineer can often greatly increase the effectiveness of a treatment by perforating for fracturing, rather than in a more conventional manner.

When perforating for fracturing, it is often desirable to only perforate a very limited section of wellbore, usually located towards the centre of the gross interval. This controls the point of fracture initiation and helps to reduce tortuosity. However, there are quite legitimate reason for wanting to perforate all of the net pay (which can often result in several sets of perforations). One of these reasons is well testing, which is used by reservoir engineers to help determine the recoverable reserves in the formation - obviously a very important task. Results from well test analysis can be misleading if the entire interval is not perforated, especially if the formation contains several discrete intervals. Therefore, the need to reduce the number of perforations and to reduce the length of the perforated interval, must be balanced with the operating company's other interests. A compromise must be reached.

CONTROLLING FRACTURE INITIATION

Perforations can be used to control the point of fracture initiation, as illustrated in Figure I, below. On the left-hand side, there is an interval that has been perforated across it entire section. When the treatment commences, fracture initiation takes place. At this point, it should be remembered that fractures are initiated by pressure, not by rate. As Frac Engineers, we often use rate to create pressure (as a consequence of Darcy's law), but it's the pressure that makes the fracture. As the pressure increases, a fracture will initiate when the pressure rises above the breakdown pressure of the weakest point along the perforated interval. This can be in at the top of the zone (frac A, below), in the middle of the zone (B), at the bottom of the zone (C) or somewhere else. There can also be more than one fracture – wherever the fluid pressure exceeds the breakdown pressure, a fracture will be initiated. Multiple fractures can result in poor fracture conductivity and early screenouts.

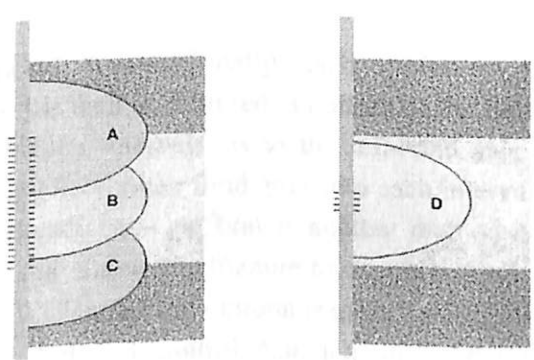


Figure I - The Effect of perforations on fracture initiation

If the interval is perforated as shown in the left-hand side of Figure I, the point at which the fracture or fractures initiate is beyond the control of the Frac Engineer. Fracs A and C have substantial sections propagated outside the interval. This results in poor coverage of the interval and a considerable amount of wasted proppant. There is also a risk that Frac A could penetrate into a gas cap or that Frac C could penetrate into a water zone.

Alternatively, the interval could be perforated as shown in the right-hand side of Figure I. In this example, the zone has been perforated over a very short interval (5 to 10 ft). This controls the point at which the fracture initiates, and dramatically reduces the chances of multiple fractures forming. If this short perforated interval is in the center of the zone, then there is a good chance that the fracture will propagate both up and down, covering the entire section and using the proppant efficiently. Alternatively, if there is a water zone close by, the interval can be perforated towards the top. This causes the fracture to initiate near the top, reducing the chances of the fracture penetrating down into the water.

Of course, once the interval has been fractured, there is nothing - other than cost – to stop a second perforation run being made to cover the rest of the interval. However, if the treatment has been effective, the fracture will be many times more conductive than the formation. Consequently, any perforation that is not directly connected to the fracture will be unproductive.

Another example of perforating to control fracture initiation is the case when multiple zones are treated simultaneously in a single treatment. The conventional method is to try a limited entry treatment but these are unreliable and difficult to control.

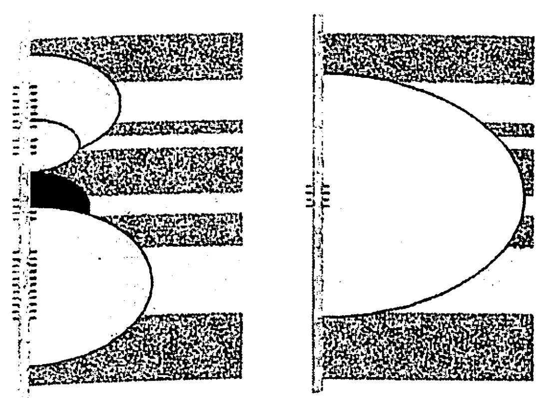


Figure II - Perforating for zonal coverage

Figure II illustrates this concept. Conventionally, each productive section of the formation is perforated individually. When this well is fractured, a portion of the fluid (dependent upon a number of variables) will enter each of the intervals, as in the left-hand side of Figure II. Limited entry fracturing is all about controlling how much fluid goes into each interval and can be very unreliable. However, if the well has not already been perforated, another method is to perforate a small section in the center of the formation, and allow the fracture to connect up all of the individual intervals (right-hand side of Figure II). Under any circumstances, a treatment that produces a single fracture is much easier to predict and control than a treatment that produces multiple fractures.

Once again, a small section (5 to 10 ft) of perforations is shot. These need to be placed roughly in the center of the interval to be covered, or slightly towards the bottom, depending upon the stress regime. Consequently, this may even mean deliberately perforating a non-productive formation, such as a shale. It can often be quite hard to convince an oil or gas company to deliberately do this.

CONTROLLING TORTUOSITY

In order to minimize tortuosity, it must be as easy as possible for the fracture to propagate from the perforations. Every single perforation is a potential source of fracture initiation, so one of the steps taken is to reduce the number of perforations to an absolute minimum, consistent with the anticipated production rate. This in turn means big holes.

Figure III - Perforation strategy for vertical wells

Another important factor is the phasing of the perforations. Ideally, this should be 180°, with the guns oriented so that they shoot perpendicular to the maximum horizontal stress. This way the holes are lined up with the direction of fracture propagation, minimizing any changes of direction between the hole in the casing and the main fracture. Most of the time it is not possible to orientate the guns in this fashion – the best strategy will then depend upon factors such as the contrast between the maximum and minimum horizontal stresses and the formation's Young's modulus. The situation is complex, but in general it is best to minimize the number of holes shot, to use big holes to minimize perforation friction, and to perforate to that the holes line up along the wellbore (see Figure III), rather than produce a spiral of holes around the circumference. The best strategy for perforating for fracturing was presented by Behrman in 1998. However, it is the author's experience that 90° phasing usually produces the least near wellbore friction in vertical or near-vertical wellbores, without getting involved in very complex strategies.

Deviated Wellbores

Hydraulic fractures tend to propagate on a vertical or near vertical plane. On a vertical well, this means that the fracture will propagate along or close to the wellbore. This minimizes the formation of multiple fractures, as the compression of the rock on either side of the fracture will make it harder for parallel fractures to grow. However, on a deviated or horizontal wellbore, the horizontal distance between potential points of fracture initiation is much greater, making it much easier to produce tortuosity and/or multiple fractures. Consequently, it is common practice for highly deviated or horizontal wells, to perforate a very short section of the formation (+/- 2 ft or less), with as many big holes as possible. This is shown in Figure IV (for a horizontal well):-

Figure IV - Perforation strategy for horizontal wells

PERFORATING FOR SKIN BYPASS FRACTURING

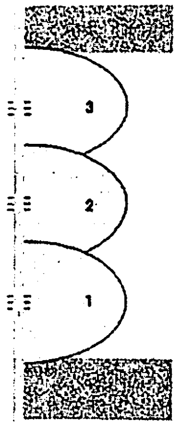


Figure V - The Effect of fracture initiation point on skin bypass fracs

Skin Bypass Fracturing is a special type of small-scale fracturing operation designed to penetrate through skin damage, and to provide effective stimulation without the cost and logistics of larger-scale treatments. Whilst it is true that SBF's may not necessarily offer such a large production increase as conventional fracturing, the stimulation is still effective, and is usually more than adequate to justify the cost of the treatment. As with any type of fracturing, the position of the perforations can have a significant effect on the results of the treatment.

STEP RATE TESTS

Step rate tests are usually performed before a hydraulic fracture treatment, as part of the fracture design process. Together with the minifrac, they are often referred to as calibration tests, as they are used to adjust the fracture model to the actual pressure response of the formation.

There are two types of step rate test, the step up test and the step down test. One is used for determining fracture extension pressure, whilst the other is used for determining near wellbore friction. Both tests can be extremely useful when designing the treatment. Whenever possible, bottom hole pressure data should be used, as this is more accurate and reliable than calculated BHTP.

THE STEP UP TEST

The step up test is used to determine the fracture extension pressure, P_{ext}. This is usually 100 to 300 psi higher than the fracture closure pressure, $P_{closure}$, which is a very important factor in fracture design. Usually the results of the step up test will be used to determine an upper boundary for $P_{closure}$ and to give the expected BHTP.

To carry out the step rate test, it is common practice to use either KCl water or linear gel. However, if this test is to be combined with the minifrac, then the actual frac fluid should be used. The test itself consists of pumping fluid into the formation at various rates. These rates start off slowly and gradually increase. For example, these could be the pump rates for a typical test; 0.25 bpm, 0.5, 0.75, 1.0, 1.5, 2.0, 3.0, 5.0 and 10 bpm. The first step is usually the lowest rate that the pumps can manage. It is important to get as many stages at low rate as possible. At each stage, first achieve the rate, then wait for the pressure to stabilize and finally record the exact pressure and rate. Then move on to the next stage.

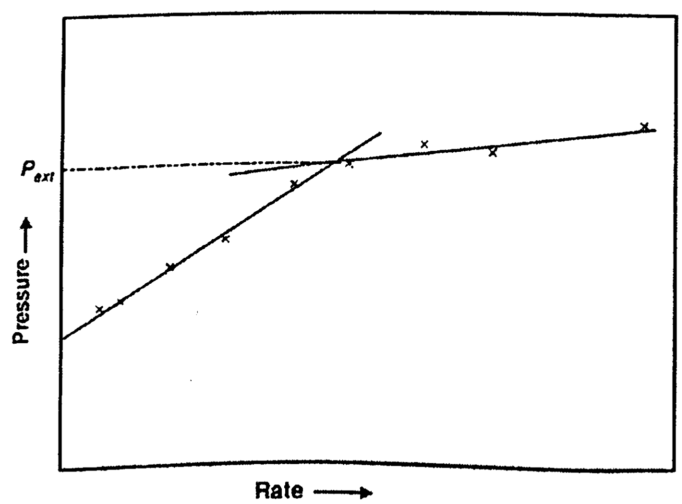


Figure I – Step Up Test

What is important with this test is to get stabilized pressure. It is not that important to get the exact rates. Often, pump operators will fiddle with the rate for 30 seconds or so in order to get exactly 0.75 bpm. This is not necessary. Get approximately the correct rate and then leave it alone, so that the pressure can stabilise and be recorded. Once the test has been carried out, a plot of pressure against rate can be made, as illustrated in Figure I.

The change in gradient of the slope shown in Figure I marks the change from Darcy radial flow (lower rates) to Darcy linear flow at higher rates. This is the point at which our fracture is created and hence this is our extension pressure.

When carrying out a step up test it is important that no artificially induced fracture exists prior to the test. Thus, if any pumping above the frac gradient has already been carried out, sufficient time should be taken for the fracture to heal up before commencing the step rate test. On very tight rocks, this could be several days.

The step rate test can also provide an indication of fracture toughness, at least in the formation close to the wellbore. In theory, the difference between the extension pressure and the closure pressure (usually obtained from the minifrac) is directly related to the fracture toughness. However, it is also heavily influenced by wellbore orientation, perforation strategy and the orientation and magnitude of the horizontal stresses.

THE STEP DOWN TEST

This test is used to determine the nature of any near wellbore friction that may exist, i.e. to see if it is perforation or tortuosity dominated. As the name suggests, the step down test is the opposite of the step up test. Instead of starting at low rates and increasing, the rates are started high and decreased.

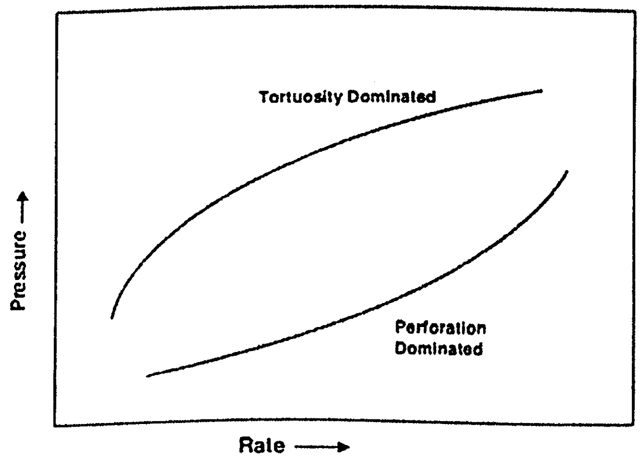


Figure II - Step Down Test

When performing the step down test, it is important that the fracture is open the whole time, otherwise the test is invalid. Therefore, this test is often carried out after a step up test. It is not uncommon to step up then step down right after. Another factor to remember when conducting a step down test is keeping the stages short as the rate is stepped down. Unlike the step up test, which starts with no fracture and ends with an open fracture, the step down test must be performed with the fracture open all the way through. Consequently, if the steps down take too long, the fracture will close before the end of the test, making the low rate data points invalid. 4 or 5 steps down, taking 10 to 15 seconds each, is all that is required. Also, make sure that before starting the step down, that the fracture has been open for at least 5 minutes - the longer the better, as smaller fractures will close more quickly than larger fractures.

Figure II shows the relationships between pressure and rate for the step down test. The different shapes of the curves indicate how the near wellbore friction is dominated by the perforations, by the tortuosity or by a combination of the two.

For perforation friction:-

$$P_{nwb} \alpha \ Q^2$$

In theory, perforation friction follows the same theory as flow through orifices, involving Bernoulli's Equation and stagnation pressure. Allowances have to be made for the diameter of the perforation (assumed to be constant) and for the discharge coefficient (a measure of how "smooth" the flow is as it goes through the orifice). The discharge coefficient is also assumed to be constant. As a result, the pressure loss is proportional to the rate per perforation, as illustrated in equation above. Generally, at this stage no significant volumes of proppant have been pumped and so the assumption that perforation diameter is constant is valid.

For tortuosity:-

$$P_{nwb} \alpha \ Q^{1/2}$$

In theory, for tortuosity dominated near wellbore friction, as the pumping rate increases, so does the width of the near wellbore flow channels, as the width of these is dependent upon pressure – the higher the rate, the higher the pressure and hence the greater the width. This is why, for tortuosity, Pnwb does not increase as fast as rate.

STEP RATE TEST EXAMPLE – STEP UP/STEP DOWN TEST

The following data was taken from a step rate test in which the rate was stepped up and then immediately stepped down again, using slick water. The data generated by the step rate test is given in table below.

Figure III shows the step up pressure-rate crossplot. Figure IV shows the step down crossplot, while Figure V shows the same step down crossplot using surface pressure. This illustrates why bottom hole pressure must always be used for step rate test analysis, even if it has to be calculated from surface data

Rate (bpm)	STP (psi)	BHTP (psi)
0.5	2030	5958
0.9	2310	6211
1	2445	6337
1.2	2600	6474
1.6	2730	6559
2	2850	6623
2.3	2910	6636
3.2	3120	6671
4.2	3450	6753
5.2	3780	6783
6.3	4224	6838
8.4	5290	6996
10.2	6280	7041
11.8	7281	7076
8.4	5180	6886
6.3	4160	6774
4.2	3271	6574
2	2580	6353

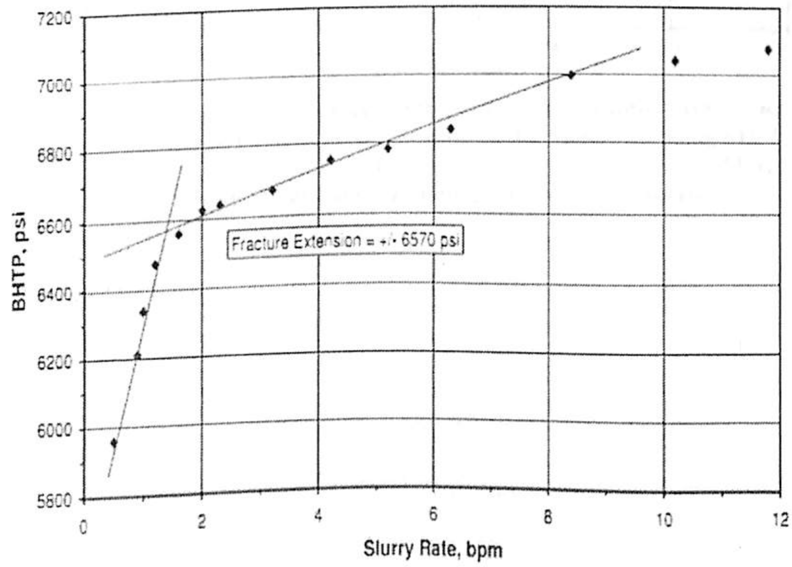


Figure III - Step up pressure-rate crossplot using the example data. This plot shows thefracture extension pressure to be at +/- 6570 psi.

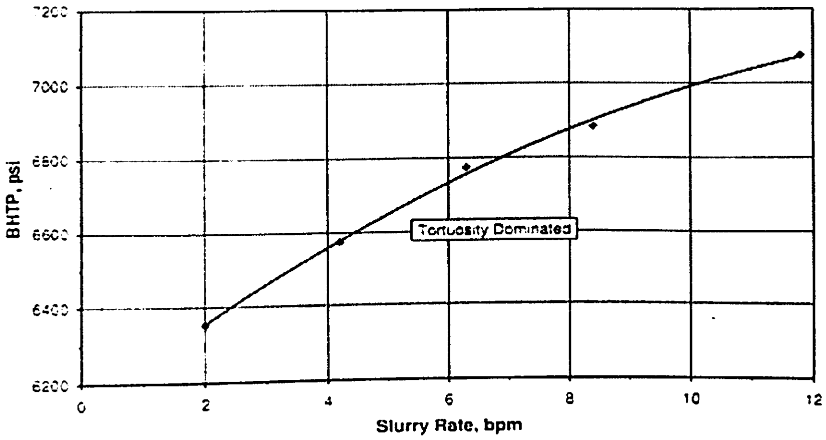


Figure IV - Step down pressure-rate crossplot for the example data. The convex shape of the curve indicates near wellbore friction dominated by tortuosity

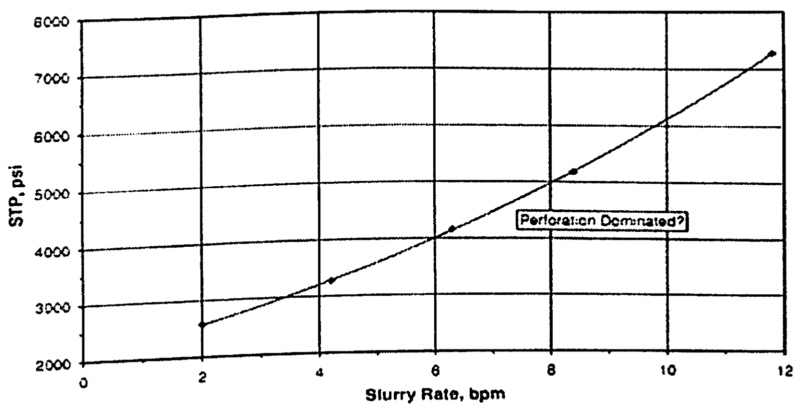


Figure V - Step down pressure-rate crossplot for the example data, using surface treating pressure (STP). This graph illustrates the danger of using STP for step rate test analysis, as in this case, the near wellbore friction would have been incorrectly diagnosed as being perforation dominated.

The purpose of the minifrac is to provide the best possible information on the formation, prior to pumping the actual treatment. Any time that the quality of information available for a frac candidate is poor, a minifrac should be planned. This includes most wells, as it is not usual to have detailed rock mechanical and leakoff data for a formation (and for the non-productive formations surrounding the zone of interest). The only time a minifrac should not be pumped is when there is reliable data available from offset wells that have been fractured (as is often the case in the US).

The minifrac is designed to be as close as possible to the actual treatment, without pumping any significant volumes of proppant. The minifrac should be pumped using the anticipated treatment fluid, at the anticipated rate. It should also be of sufficient volume to contact all the formations that the estimated main treatment design is anticipated to contact. A well planned and executed minifrac can provide data on fracture geometry, rock mechanical properties and fluid leakoff – information that is vital to the success of the main treatment.

PLANNING AND EXECUTION

Bottom Hole Data

Do whatever it takes to get bottom hole pressure data for the minifrac (and also for the step rate test), as this is far more accurate than data calculated from the surface pressure. Bottom hole data can be obtained using three acquisition methods:-

1. Real Time Gauges. These can be run on wireline or can be part of the well's completion. These gauges allow both pressure and temperature to be recorded real time at the surface. Usually, it is possible to run a data cable so that the pressure data can be incorporated real time with the standard frac data already being recorded. This is the best possible situation for the Frac Engineer.

2. Memory Gauges. These are gauges that are run in on wireline or slick line, and hung in either a specially designed gauge carrier, or some other suitable position (such as an empty gas lift mandrel). Alternatively, they can just be held on slick line at a specific depth. After the mini-frac and the step rate test are completed, the gauges are retrieved and the data is downloaded at the surface. This data is then merged with the surface data that has already been collected. This is the most common method of using gauges, even though there is a delay caused by the retrieval of the gauges.

3. Dead String/Live Annulus. Both of these methods work on the same principle. With the live annulus, the well is completed with tubing but no packer (or the packer has not been set, or the packer is fitted with a circulating valve that is left open during the treatment). Basically, the annulus is exposed to the BHTP during the treatment, and shows a corresponding surface pressure. As the fluid is not moving in the annulus, BHTP can be easily calculated, provided the density of the fluid in the annulus is known. Most fracture monitoring programmes have the capability to perform this real time. A dead string relies on the same principle, but instead employs a

small diameter tubing string, inside the actual treatment tubing. A common example of this is coiled tubing placed inside a large diameter frac string.

Remember that it is more important to get downhole pressure data during the minifrac and the step rate test, than it is during the actual treatment. Companies that supply gauges are often reluctant to have proppant pumped past them (this also applies to wireline cables). Consequently, it is common to have the gauges in the well for the minifrac and the step rate test, and then retrieve them prior to pumping any proppant.

Most bottom hole pressure gauges also record temperature. This data, whilst not as important as pressure data, can also be useful:-

1. The data can provide a good check of the bottom hole static temperature, to ensure that the correct temperature has been used for designing the fluid system.
2. The data can provide a good value for the bottom hole treating temperature. This is especially important when performing treatments with nitrogen and/or carbon dioxide and also for treatments where tubing shrinkage due to cooldown is critical.
3. If the gauges have been run on wireline or slick line, then it is possible to run the gauges past the perforations after the minifrac and the step rate test, to perform a temperature log. This is a plot of temperature against depth. By looking at how far each the perforations have cooled down – and how this cooling down varies across the perforated interval – it is possible to get a qualitative indication of where the fluids are going and hence were the fracture(s) is(are) initiating.

Because the rheology of the fracturing fluid is constantly changing as the minifrac is being pumped, and because the well is continually cooling down, calculated friction pressures can often be unreliable. This in turn means that a BHTP calculated from a STP can also be unreliable. This is why it is important to obtain reliable downhole data, from which to base the frac design.

Fluid Volumes and Rates

Deciding what volume to pump for the minifrac can be difficult. Ideally, we wish to pump the minimum volume necessary to gather accurate formation and fracture data. However, remember that we are not just interested in getting data on the producing formation – we are also after data on any formation above and below that may be contacted by the fracture. This means that as a minimum, we must pump at least the two-thirds of the anticipated pad volume. On low permeability wells we may have to pump significantly more than the pad volume.

The best method to decide the minifrac volume, is to run a few simulations for the minifrac, based on the data used to design the main treatment. Adjust the minifrac volume such that it will contact all the formations that main treatment will contact.

As we are trying to create a treatment that is a close as possible to the actual treatment (minus the proppant), the minifrac should be pumped at the same rate as the anticipated treatment.

The minifrac should be displaced with slick water. The displacement volume should be enough to displace the minifrac to just short of the perforations, to ensure that the near wellbore fracture(s) close on frac fluid, rather than slick water. To do this, it is common to under-displace by +/- 5 bbls.

Fluid Type

As stated above, we are trying to create a test that is as close as possible to the actual treatment, minus the proppant. This means that the minifrac should use the same fluid as the anticipated treatment. In fact, every step should be taken to ensure that the fluids used in the minifrac and the main treatment are as identical as possible, so that fluid related data gathered in the minifrac is as valid as possible for the main treatment.

Often, an operating company will suggest using slick water for the minifrac, as a way of saving time and money. This is a false economy, as the subsequent minifrac will have only a passing resemblance to the fracture that will be created by the main treatment. In particular, the fluid leakoff will be (usually) significantly greater with slick water. This results in faster than normal fracture closure, and smaller than normal fracture geometry.

Recently, some Engineers have argued that because of the wall building effects of the fluid used in the minifrac, the leakoff for the main treatment can be lower than that for the minifrac. To compensate for this, increased breaker loadings are used in the minifrac.

Wellbore Fluid

Usually, there is some kind of fluid in the wellbore prior to the minifrac. Often, this fluid will be slick water from the step rate test, or produced fluids. Unless this fluid can be circulated out of the well ahead of the minifrac fluid, it will be injected into the formation as part of the minifrac. Obviously, having two different fluid types in the fracture makes the job of analysing the minifrac data that much more difficult, so every effort should be taken to minimise the volume of fluid ahead of the minifrac fluid. On some wells, this can be achieved by circulating the minifrac fluid into position. However, on most wells this cannot be done, and the Frac Engineer has to live with the situation.

Pressure Decline

The data collected during the pressure decline (i.e. after the minifrac has been displaced and the pumps are shut down) is just as vital as the data collected whilst pumping. It is therefore important to monitor the pressure decline, sometimes for up to 2 hours after the minifrac is completed. During this period, it is important that nothing is done to compromise the quality of this data. Any opening or closing of valves, hammering on equipment or circulating of fluids should be avoided at all costs. In particular (and this may sound obvious, but it does happen) the wellhead should not be closed during this period. There should also be no pumping into the annulus, as this will affect the tubing pressure. Once the Frac Engineer is sure that the fracture has closed, the well can be shut in and normal activities resumed.

Proppant Slugs

Many Engineers prefer to pump a proppant slug in the minifrac. This is a proppant stage in the middle of the minifrac, often containing as little as 500 lbs of proppant. This slug will test the near wellbore region for tortuosity. Ideally, the proppant slug should pass into the formation with no detectable pressure rise. If the pressure rises when the proppant flows into the formation (and worse still, if it rises and does not come down again), then there is restricted flow in the near wellbore region – tortuosity. A series of proppant slugs of increasing concentration can be use to effectively diagnose the severity of a tortuosity problem.

Multiple Minifracs

Some companies, especially those operating in high permeability formations, prefer to use more than one minifrac. The first minifrac is designed to be small, to penetrate only into the zone of interest and provide good leakoff and closure data on this formation. The second minifrac is larger, designed to penetrate further and give a better idea of the overall fracture geometry. Obviously, the use of two minifracs provides more data than just a single treatment. However, in most cases this is probably not necessary. A well-designed and executed treatment should be able to provide the Frac Engineer with all the necessary data. However, there are cases when it is very difficult to interpret the minifrac data, through no fault of the treatment. Some formations are just too complex to easily analyse. In such cases, when the data from the first minifrac defies scrutiny, often the only way to proceed is to pump a second minifrac, in the hope that this data will be better.

ANATOMY OF A MINIFRAC

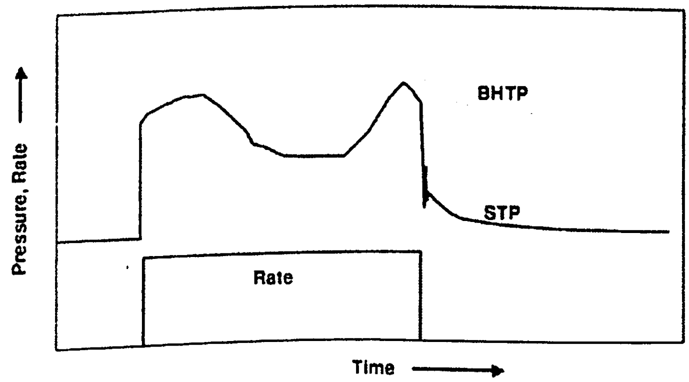


Figure I - Typical minifrac job plot, showing BHTP, STP and rate

Figure I shows a typical job plot from a minifrac:-

Three important parameters are used – to a greater or lesser extent – in obtaining the required data from the minifrac. The BHTP (ideally actual pressure data, rather than calculated) is the main variable, as this tells us the way the fracture is behaving and the amount of work being performed on the formation by the fluid (or vice versa). The rate is important for determining the fracture geometry, as the volume of fluid pumped into the formation, less the volume of fluid which has leaked off, is equal to the volume of the fracture.In addition to these two parameters, the proppant concentration can also be important, if proppant slugs have been pumped.

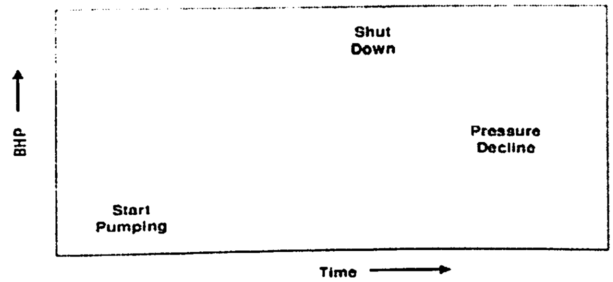


Figure II - Expanded plot showing BHTP

Figure II shows an expanded portion of Figure I, giving the BHTP more detail. Generally, a large number of minifracs will have this same basic shape, although by no means all. The area between the start of pumping and the shut down is often shaped like this, with the pressure declining initially and then increasing towards the end. In terms of Nolte analysis, this means that the fracture is initially growing in a shape which is radial or preferentially vertical (rather than horizontal), but after a period of time the height growth becomes more controlled, and the preferential growth direction is horizontal.

DECLINE CURVE ANALYSIS

As soon as the pumps shut down, the pressure will start to decline. Initially, the net pressure will still be positive, and the fracture may still propagate. However, as soon as the fluid input into the fracture stops, the fracture will start to decrease in volume, as fluid is still leaking into the formation. As the fluid volume in the fracture (and hence the volume of the fracture itself) decreases, the fracture width also decreases until the fluid volume in the fracture is zero – the fracture has closed.

The time taken for the fracture to close defines the rate at which the leakoff is occurring, whilst the pressure at which the fracture closes (and the difference between the treating pressure and the closure pressure) tells us how hard it will be to produce the required fracture. the size and shape of the fracture.

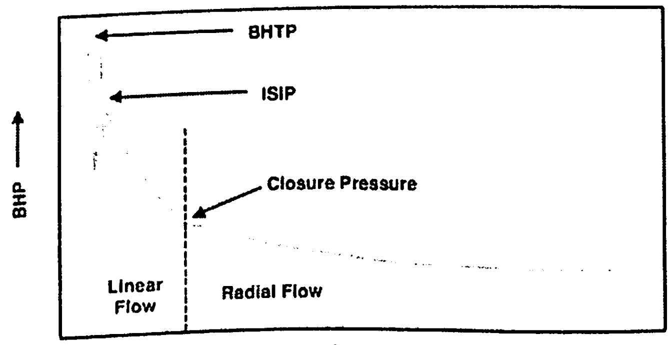


Figure IV - Typical minifrac pressure decline curve

It is possible to see several distinct features on above curve, although it must be emphasized that Figure IV is idealised and that actual minifrac pressure decline curves are rarely thisclear. Features which the Frac Engineer needs to identify include:-

1. BHTP – the actual bottom hole treating pressure. This is the pressure inside the well, at the middle of the perforated section that is being treated. Ideally, this should be measured via a gauge or a dead string.

2. ISIP – the instantaneous shut-in pressure, also referred to as the instantaneous shut down pressure, or ISDP. This is the bottom hole treating pressure just after the pumps shut down, and before the pressure the pressure starts declining. Often, this point is hidden by noise generated by "pipe ring" as the pressure suddenly drops. In that case, the decline curve has to be extrapolated backwards in order to find the ISIP.

The difference between the ISIP and the BHTP is due purely to friction pressure loses in the near wellbore area. Therefore, this difference can often be used as a quantitative assessment of tortuosity.

3. Closure Pressure, $P_{closure}$, is the pressure at which the fracture closes, and is often denoted by a change in gradient on the pressure decline curve. The difference between the ISIP and the closure pressure is referred to at the net pressure, or P_{net}. The net pressure is a measureof how much energy is being used to create the fracture and so is a very important parameter. However, it should be remembered that the net pressure will usually vary throughout the treatment, and that this method only captures the net pressure right at the end of the treatment. The closure pressure is also a measure of the in-situ stresses in the formation

4. Closure Time. The closure time is the time taken for the fracture to close, after the pumps have shut down. If the geometry of the fracture is known (or, more likely, can be estimated from a model), then the volume of fluid in the fracture is also known. Therefore, if the length of time taken for the fracture to close is also known, the rate at which the fluid is leaking off can be easily calculated.

The are various different methods for helping the Frac Engineer pick closure pressure, as often it is very difficult to spot the change in gradient on the pressure decline curve.Additionally, there may be more than one closure pressure, if multiple fractures are closing. Finally, the effects of tortuosity may mask the closure pressure, as there is evidence to suggest that the tortuosity can, in some cases, close before the main part of the fracture.

PRESSURE MATCHING

Another method for analysing minifrac data, is to carry out a process known as a pressure match (also referred to as a history match). In this process, the fracture simulator is "tuned" until the simulator's predicted net pressure matches the actual net pressure. This "tuning" process is carried out by adjusting variables such as Young's modulus, Poisson's ratio, fracture toughness, stress gradient, near wellbore friction, leakoff rate, and spurt loss.

Pressure matchingis a very powerful tool, providing the user is aware of the limitations. The user is actually adjusting the computer model to produce the same pressure response as the formation. Once the model has been adjusted (the pressures have been "matched"), any potential treatment schedule can be runon the simulator, and its effects assessed. This means that once the match has been made, the Frac Engineer can very quickly adjust the treatment schedule to produce a fracture of the required geometry.

Limitations of Pressure Matching

1. Complexity. Because so many variables are adjusted, in so many different rock strata, a Frac Engineer may often have to keep track of 20 or more variables. Each of these variables can

affect the overall outcome of the simulation. Therefore, a Frac Engineer must remain aware of what variable changes and values are realistic and what are not.

2. Non-Unique Solution. Because there are so many variables to adjust, it is quite possible for 2 Frac Engineers to produce good pressure matches, using different values. Often, these solutions will only produce similar net pressure responses for the particular data set being analysed, so that when a different treatment schedule is simulated (such as the actual treatment schedule to be pumped), two significantly different fractures are generated. Which one is closest to the truth?

3. Data Quality and Model Inaccuracies. As with any type of computer analysis, the results are only as good as the raw data (garbage in = garbage out). In particular, errors generated by the use of surface pressure data to calculate BHTP can sometimes render pressure matching almost ineffective. For instance, it is quite possible to interpret a gradual rise in STP as good fracture containment, whereas in reality it may have been caused by variations in fluid properties. Even if the quality of data is good, the final result is only as good as the model itself. Just because a model predicts a fracture that is 150 ft long and 100 ft high, doesn't mean that this is what happens in the ground. In fact, two different fracture simulators will almost always produce different fractures, when fed the same input data. Again, which one is closest to the truth?

The study of the theory of how the fracture models work will only get a Frac Engineer so far in trying to solve these conundrums, especially as the companies responsible for the most widely used fracture models do not publish significant parts of their theory. Unfortunately, in this case there is no substitute for experience.

The Frac Engineer's job is not over once the treatment has been pumped. Aside from monitoring fluid samples and preparing a post job report, the Engineer also needs to evaluate exactly what has happened in the formation. This is essential if the operating company plans to do more than one frac in a formation.

The simplest method for assessing the effectiveness of the treatment is to compare before and after production. However, this does not really tell us much. In order to increase the effectiveness of future treatments, we need some idea of the size and shape of the fracture that was actually produced.

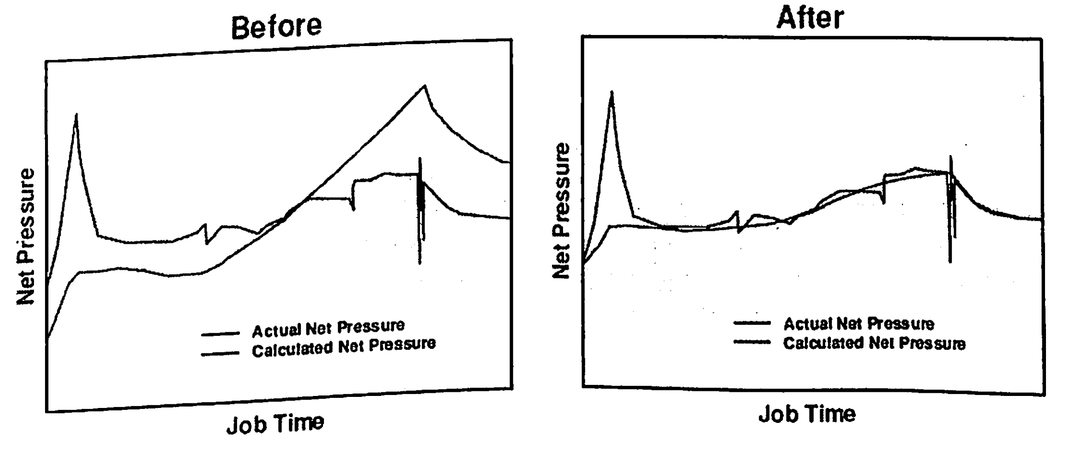
Some of the methods described below – such as pressure matching - are relatively easy for the Frac Engineer to perform. However, other methods, such as tiltmeters and microseismic, require considerable expenditure and planning by the operating company. This means that plans for post-treatment evaluation must be made when planning for the treatment itself.

PRESSURE MATCHING

Pressure matching is part science and part art. In order to perform a quick and efficient pressure match, it is essential to have a good knowledge of the fracturing process, an understanding of the various rock mechanical properties, an understanding of fracture mechanics and, ideally, a reasonable idea of how the fracture simulator works. In spite of this need for an understanding of the physics behind the fracturing process and the fracture simulation, there is still an art to pressure matching. Some Frac Engineers have a feeling for this process, and some do not.

Pressure matching is a very powerful tool that allows the Frac Engineer to "tune" the fracture simulator to the formation. The idea being that once the simulator has been tuned, further fracture simulations can be performed with a high degree of accuracy.

The Process of Pressure Matching
Pressure matching is all about making the simulator predict the same pressure response as the reaction actually produced by the formation. This is illustrated in Figure below:-



Pressure matching. The variables in the simulator are adjusted to make the calculated net pressure match the actual net pressure.

With reference to figure, before the pressure match (LHS), the net pressure predicted by the fracture simulator does not match the actual net pressure in any way. After the pressure match has been performed (RHS), the computer predicts a very similar pressure response to that of the actual treatment data. Now - according to the theory - the simulator has been "tuned" to the formation. This allows the Frac Engineer to input any desired treatment schedule, and the simulator will be able to predict the fracture geometry with a reasonable degree of precision.

There is no doubt that the advent of pressure matching has greatly improved the success rate and effectiveness of hydraulic fracturing. Modern fracture simulators equipped with this facility have gradually made the process increasingly user-friendly, helping to reduce the "black art" associated with frac engineering, as more and more Engineers feel capable of designing a fracture treatment.

However, there are some definite limitations to this process:-

1. **Garbage In = Garbage Out**. The computer model of the formation generated by this process is only as good as the data used to create it. Poor data on items such as permeability, net height, fluid properties (both formation and fracturing fluids) and perforations can make an otherwise perfect pressure match almost irrelevant. Another major source of errors is the use of surface pressure data to calculate *BHTP*. In order to calculate *BHTP*, the model first needs to calculate the fluid friction pressure, something that is notoriously difficult to do for a crosslinking fluid. Variations in fracturing fluid properties (such as those caused by problems with liquid additive systems, or varying gel properties) can also be very difficult to account for. Therefore, the Frac Engineer should do everything possible to get reliable bottom hole pressure data, such as that from a gauge or dead string.

2. **No Unique Solution.** The process of pressure matching involves adjusting four major variables (Young's modulus, stress, fracture toughness and leakoff) and many other minor variables, for each rock strata affected by the fracture, until the pressure response predicted by the model matches the actual pressure response of the formation. This means that the Frac Engineer may have 30 or 40 variables available for adjustment. It is therefore quite possible for two Frac Engineers to get good pressure matches, but with significantly different sets of variables.

3. **The Fracture Model.** At the end of the day, the results of the pressure match are only as good as the fracture model itself. Without a doubt, modern fracture simulators are tremendously advanced – the product of more than 20 years of innovation, experimentation and inspiration. However, the fact remains that different fracture simulators will predict different fracture geometries for the same input data. Which one is right? Probably they are all wrong – so the correct question to ask is which one is closest to the Truth? This is difficult to say, and the subject of considerable debate in the fracturing industry. The popular conception is that one fracture simulator is good for a certain type of formation, whilst another is good for a different type. The debate continues.

It should also be remembered that in general (*GOHFER* excepted) the widely used frac models all predict a single eliptically-shaped fracture, either side of the wellbore, symmetrical around the wellbore. In reality, the fracture is probably much more complex than this. It is highly unlikely that the fracture - or more likely fractures - behaves in such a regular and predictable manner. What the fracture simulators do is predict a simplified fracture that behaves, on average, in a similar fashion to a much more complex reality

THE FOUR MAIN VARIABLES

There are four main variables that the Frac Engineer should be adjusting in order to achieve the pressure match – that is to say, four main variables in each formation affected by the fracture. These variables are Young's modulus, stress, fracture toughness and fluid leakoff.

Fracture Toughness, K_{Ic}

Strictly speaking, K_{Ic} is the critical stress intensity factor for failure mode 1. However, it is commonly referred to as the Fracture Toughness and is a measure of how much energy it takes to propagate a fracture through a given material. In hydraulic fracturing, where the energy needed to propagate the fracture comes in the form of fluid pressure, fracture toughness tells us what proportion of the available energy is used to physically split the rock apart at the fracture tip. As pressure is essentially energy per unit volume, K_{Ic} tells the Frac Engineer how much net pressure is required to propagate the fracture.

Generally speaking, soft plastic formations will have high fracture toughness, whilst hard brittle formations will have low fracture toughness. There is also an approximate inverse relationship between Young's modulus and fracture toughness – hard formations tend to have a high E and a low K1c, and soft formations tend to be the other way around. For the Frac Engineer, increasing the value of fracture toughness will tend to make it harder for a fracture to propagate through the rock. Therefore, an increase in fracture toughness will generally make the fracture shorter and wider. However, an increase in fracture toughness for just one formation will tend to divert the fracture into an adjacent formation. For example, if the K_{Ic} is increased in the perforated interval, the fracture will grow into the adjacent formations, above and below. This has the effect of limiting the fracture length and increasing the fracture height.

In soft formations, do not be afraid to use quite large values for this property, even several times the default values included in the simulator

Fracture toughness is a material property and cannot be altered by anything under the control of the Frac Engineer. It is also a property that is very difficult to measure. There are several laboratory methods for determining K1c, but these are limited in their reliability, as fracture toughness is highly dependent upon down hole conditions and the overall geometry of the fracture. However, if core samples are available, fracture toughness can be estimated from laboratory measurements of yield stress and Young's modulus, provided this is determined under tri-axial loading, at bottom hole temperature and pressure.

Remember that some fracture models (e.g. *FracPro* and *FracproPT*) have moved away from the concept of Fracture Toughness and instead model non-linear elastic effects at the fracture tip as being more significant. In such models, variations in Young's modulus and in-situ stresses are far more significant.

Young's Modulus, *E*

In order for the fracture to propagate it must obtain width, to a greater or lesser extent. In order to do this, the rock on either side of the fracture has to be compressed. Young's modulus defines how much energy is required to perform this compression. Rocks with a high Young's modulus will require a lot of energy (a.k.a. net pressure) to compress. In these formations, fractures tend to be relatively thin, and the rock is referred to as "hard". Similarly, rocks with a low Young's modulus require relatively little energy to produce width. In these formations, fractures tend to be relatively wide, and the rock is referred to as "soft".

Young's modulus is a fundamental material property and, like the fracture toughness, cannot be altered by anything under the Frac Engineer's control. It can be measured from core samples, provided these tests are carried out under tri-axial load conditions, at bottom hole temperature and pressure. In some formations (especially weak or unconsolidated rocks), Young's modulus may not be constant.

Fracture mechanics, rock mechanics and fracture simulation require the use of the static Young's modulus. This is the Young's modulus measured under static - or relatively static –conditions, such as those that occur whilst fracturing. Another form of Young's modulus, the dynamic Young's modulus (the Young's modulus measured under dynamic conditions), can be measured by so-called "stress logs". These logs, generated by a dipole sonic wireline tool (also called a sonic array), measure dynamic Young's modulus and Poisson's ratio by measuring the transit time of both shear and compression sonic waves. However, there can often be a significant difference between dynamic and static values, which renders the actual values reported on stress logs to be unreliable.
However, stress logs can accurately report contrasts in Young's modulus, which are almost as important as the absolute values themselves.

An increase in Young's modulus makes it harder for the fracturing fluid to produce width. Therefore, increasing this variable will make the fracture thinner, higher and longer, and *vice versa*. Increasing E only in the perforated interval will have the effect of forcing the fracture out of the zone of interest – i.e. increasing fracture height. A decrease in E has the opposite effect.

In-Situ Stress, σ

In-situ stress (often referred to as confining stress or horizontal stress) is the stress induced in the formation by the overburden and any tectonic activity. Put simply, it is pre-loading on the formation, the stress that has to be overcome (or pressure that has to be applied) in order to actually start pushing the formation apart. The actual bottom hole fracturing pressure is the pressure required to overcome these in-situ stresses, plus the pressure required for propagating the fracture (as a consequence of fracture toughness) and the pressure required to produce width.Factures will tend to propagate perpendicular to the minimum horizontal stress (i.e. along the line of least resistance). So the in-situ stress of a formation is the minimum horizontal stress of the formation, plus any tensile strength the rock may posses, and less any effects due to reservoir pressure.

As the horizontal stress only exists because of the overburden (ignoring tectonic effects), it is highly dependent upon the Poisson's ratio of the formation. At the limit, a Poisson's ratio of zero means that the horizontal stresses are equal to zero, plus the effects of pore pressure. This is a theoretical minimum – in practice no material will ever have a Poisson's ratio of zero. At the other limit, the maximum theoretical value for Poisson's Ratio is 0.5 – at this value, the horizontal stresses will be equal to the overburden, plus the effects of pore pressure.

So-called "stress logs" actually measure the dynamic Young's modulus and Poisson's ratio of the formation. Therefore, if the overburden is known (derived from a density logs and the TVD of each formation), the approximate in-situ stress can be calculated. However, the stresses generated from this procedure are derived from the dynamic (rather than static) Poisson's ratio. Therefore, any stresses generated by this method are unreliable. The absolute value of these stresses cannot be trusted – however, stress contrasts between formations can be used as an indication of potential fracture height containment.

In the pressure matching process, an increase in s means a reduction in net pressure (for a fixed *BHTP*). This means that the fracturing fluid has less energy available to fracture the formation, and so the width, the height and the length of the fracture are all decreased. This in turn means that the volume of the fracture has decreased. However, the same volume of fluid has been pumped into the formation, so an increase in s also has the effect of increasing leakoff rate and decreasing fracture efficiency. The opposite effect applies for a decrease in in-situ stresses.

Fluid Leakoff Rate, Q_L

The fluid leakoff rate can be controlled by altering a number of variables, depending upon the fracture simulator being used, and the fluid leakoff model being employed:-

Pressure differential (fracturing fluid pressure minus pore pressure)
Formation permeability
Formation porosity
Formation compressibility
Formation fluid viscosity
Fracturing fluid filtrate viscosity
Fracturing fluid wall-building coefficient
Spurt loss.

A lot of these variables are difficult to measure or determine. However, the Frac Engineer should remember the ultimate objective of determining fluid leakoff – to calculate the volume of the fracture. To this end, the simulator has to be able to accurately calculate the volume of fluid lost through each unit area of the fracture face. Whether or not this is achieved by varying the permeability or the wall building coefficient is almost irrelevant. On top of this, fluid leakoff can be dramatically complicated by fracture fluid flow into fissures or natural fractures, the geometry of which can vary with the net pressure.

In most cases, the Frac Engineer will have reasonable data for some of these values – and will have to guess at others. Therefore, a good strategy is to fix those values that have reasonable data, and vary the others, until the desired leakoff is obtained.

Fluid leakoff is a loss of energy from the fracturing fluid, as the total energy available for propagating the fracture is equal to the net pressure multiplied by the fracture volume. High leakoff means low fracture volume, and *vice versa*. Therefore, and increase in fluid leakoff will tend to decrease width, height and length. The opposite applies for a decrease in leakoff.

Summary of the Effects of the 4 Main Variables

The basic effect of each of these variables – when applied to a fracture in a single formation – can be summarised in table below:-

Variable	Effect of an Increase in Selected Variable			
	Height	Length	Width	Net Pressure
Fracture Toughness, K_{1c}	Decrease	Decrease	Increase	Increase
Young's Modulus, E	Increase	Increase	Decrease	Increase
In-Situ Stress, σ	Decrease	Decrease	Decrease	Decrease
Fluid Leakoff Rate, Q_L	Decrease	Decrease	Decrease	Decrease

The effects of an increase in each of the four, main pressure matching variables. Note that these are the overall effects when the change is taken in isolation (i.e. no other changes take place). It also assumes that the fracture is unaffected by boundary layers above and below.

This table should be used with caution, as it applies only when the fracture is confined within a single formation. If the fracture propagates into separate formations above and below the productive interval, then an increase in (for instance) fracture toughness will make it harder for the fracture to propagate through the main formation, forcing the fracture up and down. So, in this instance, an isolated increase in a property in just one formation, can actually *increase* the fracture height.

The Effect of Poisson's Ratio

Poisson's ratio is at the same time both important and largely irrelevant to pressure matching. It is important, because it has a major effect of defining the horizontal stresses in a formation. However, in most cases, the Frac Engineer will be determining these stresses form pressure data, not from Poisson's ratio data. In most fracture simulators, Poisson's ratio is used in the form $(1 - v^2)$ to modify Young's modulus (i.e. $E/(1 - v^2)$ – the plane strain Young's modulus). This means that a large change in Poisson's ratio, say from 0.25 to 0.35, only produces a change in $(1 - v^2)$ from 0.9375 to 0.8775 (so that a 40% increase in n produces only a 6.4% decrease in$(1 - v^2)$.

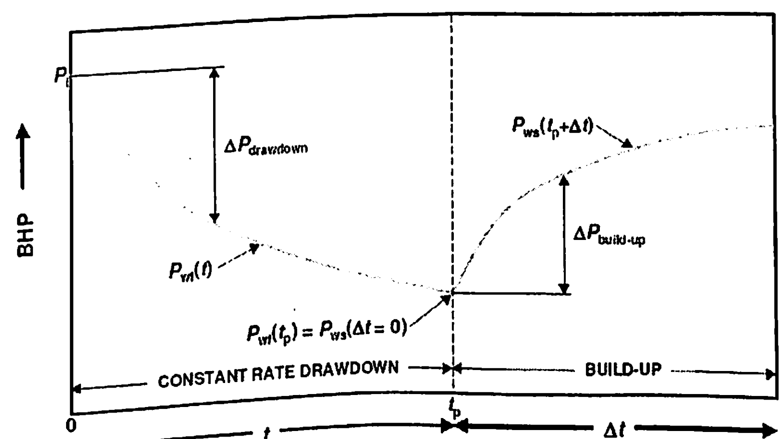
Therefore, the Frac Engineer should not spend too much time varying Poisson's ratio during the pressure match. Input what seem to be reasonable values, and then ignore it.

WELL TESTING FOR FRACTURE EVALUATION

Well testing is sometimes used both to assess the effect of the treatment and to help determine the size and shape of the fracture. To do this, well tests have to be performed both before and after the treatment. Data that is collected before the treatment is used to help evaluate the fracture geometry afterwards.

Both pre- and post-treatment tests should be performed at constant rate (or as near as possible), rather than at constant drawdown, and should be followed by a shut in (or pressure build-up) period, lasting for at least as long as the flow time. In practice, it is possible to monitor the pressure build-up real-time and see when the build-up can be terminated. The post-treatment well test can take some time, as treatment fluids must be recovered first, and the well must reach some kind of relatively steady flow.

Figure below illustrates the basic anatomy of a drawdown / build-up well test.



Anatomy of a drawdown / build-up well test (after Agarwal, 1980)

In Figure, there are several variables that are often referred to in well test analysis, which can be broken down into two groups – time and pressure. All pressures refer to BH pressure. At the start of the well test $t = 0$, and the BHP = P_i, which ideally will be the reservoir static pressure. Sometimes this is not the case, if the well has not been left static for a long enough period. However, this can be allowed for in well test analysis. As the well is produced at a constant rate, the length of time the well has produced for is called t and the flowing BHP is referred to as P_{wf}. Because this variable is dependent upon t (the longer the well is produced, the lower the BHP), it is said to be a function of t, and so the notation $P_{wf}(t)$ is used to denote this. The difference between the initial pressure (P_i) and the actual flowing pressure ($P_{wf}(t)$) is referred to at the drawdown, or $\Delta P_{drawdown}$. The well is flowed at a constant rate (which may require the varying of chokes) until it is shut in. At this point, t is said to equal the producing time, t_p (which is a constant, for any given test). After the well is shut in, the nomenclature Δt is used to describe the shut in time, such that at the point of shut in $t = t_p$ and $\Delta t = 0$. Thereafter, time is described as $t_p + \Delta t$, with t_p fixed and Δt increasing as the build-up progresses. At the point of shut in, the BHP pressure is referred to as $P_{wf}(t_p)$ – well flowing wellbore pressure at t_p – or as $P_{ws}(\Delta t = 0)$, the static wellbore pressure at $\Delta t = 0$. These two pressures are identical. After shut in, during the pressure build-up, the now static BHP is referred to as $P_{ws}(t_p+\Delta t)$ – this means that the wellbore static pressure (P_{ws}) is a function of shut in time ($t_p+\Delta t$). Finally, the difference between the shut in pressure ($P_{wf}(t_p)$ or $P_{ws}(\Delta t=0)$) and the wellbore static pressure ($P_{ws}(t_p+\Delta t)$) during the build-up is referred to as the build-up pressure, or ΔP build-up.

Figure above illustrates the most basic type of well test, the constant rate drawdown and static build-up test. This type of test can be applied to the well both before and after the treatment.

HORSEPOWER REQUIREMENTS

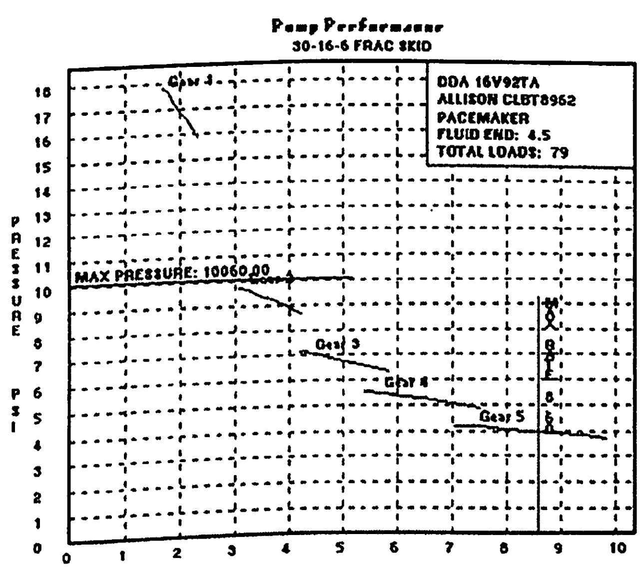
Working out horsepower requirements is a relatively easy thing to do, provided you know the expected treating pressure and slurry rate:-

$$HHP = STP \times \text{Slurry Rate}/40.8$$

where STP is in psi and Slurry Rate is in bpm. The 40.8 is simply a conversion factor for the units (in the SI system, pumping power – in kW – is directly equal to pressure (kPa) multiplied by rate (m^3/sec)). This formula will tell you how many pumps of what size you need on location. Remember to have at least 20% excess horsepower on location and - as a minimum - mobilise at least one spare pump. This excess capacity is required in case of pump failure or higher than expected treating pressures.

It is also worthwhile looking at the set of curves supplied with each pump – called "pump curves". These curves show the maximum rate and pressure that the pump can run at in each gear. Figure given below shows an example.

If a treatment is going to be close to the maximum power for a given pumping unit, it is recommended that the pump curves be consulted in order to confirm that the pump can actually do the treatment.



Typical pump curves. This set is for a 30-16-6 frac skid, with a 16V92TA engine, CLBT8962 transmission and a pacemaker pump with a 4.5 inch fluid end. Nominal rating of th pump skid is 700 HHP

HOSES

Suction Hoses

It is essential that sufficient suction hoses be used between the tanks and the blender. The only force available to move the fluid to the blender is the suction of the inlet pump and hydrostatic pressure from a difference in fluid levels. This is not much. In order to ensure that the suction pump receives fluid at sufficient rate, a simple rule applies;

One 4" diameter 10' suction hose will carry up to 10 bpm of gel

If 20 bpm is required, then two hoses will be needed, and so on. In addition, longer hoses will carry less rate. For instance, 20' of 4" diameter hose will only carry half as much rate, i.e. 5 bpm. So if 20 bpm were required from tanks which were 20' away, 4 x 4" flow lines would be required.

From this it is easy to see why the blender is usually placed as close as possible to the frac tanks, and why the frac tanks are often manifolded together with 8" (or larger) diameter lines.

Also consider the comparative diameter of manifolds and suctions hoses. For instance:-

An 8" manifold has a flow are of 50.26 sq inches. This corresponds to the same flow area as 4 x 4 inch hoses (50.24 sq inches). Therefore, there is little point in building an 8" manifold and then using only 3 x 4" suction hoses.

Finally, remember that there is a difference between suction and discharge hoses. Suction hoses need to be rigid, otherwise the suction pump of the blender can suck them flat. Discharge hoses, which generally do not have to carry suction, are often made from non-rigid hoses, which collapse flat when there is no fluid in them. This makes for easier storage and makes the hoses easier to carry. As a general rule-of-thumb, suction hoses can be used for the discharge (provided they have the correct pressure rating) but discharge hoses cannot be used on the suction.

Discharge Hoses

The discharge hoses run from the blender to the high pressure frac pumps. Generally, one discharge hose is required from the blender to each pump. These hoses do not need to be rigid but must have sufficient pressure rating. They must also have crimped connections (similar to high pressure hydraulic hose connections) and not the old-style clamps. Discharge hoses should also be fitted with "whip-checks" at each connection.

For rates below 5 bpm per pump, a single 3" discharge hose is required for each pump. At rates above 5 bpm, a single 4" hose should be used - although at very high rates (15 bpm +), more than one hose may be required.

High Pressure Flow Lines

When pumping abrasive fluids – such as a frac gel with proppant – down a high pressure treating line, there is a limit to how fast it is advisable to pump. Above this pump rate, seals on chiksans, swivels and hammer unions start to wash out. It is generally accepted in the industry that the velocity of the frac fluid should not exceed 40 ft sec-1. Therefore:-

$$Q_{max} = 2.33\ d^2$$

where Q_{max} is the maximum flow rate down any single high pressure line, in bpm, and d is the inside diameter of the line, in inches.

Important Points

1. The actual inside diameter of high pressure flow lines is often significantly less than the nominal diameter. Equation given above should be used with the actual diameter. This is illustrated in figure given below.

2. HP flexible lines, such as Coflexip hoses, have separate guidelines. For these, follow the manufacturer's instructions.

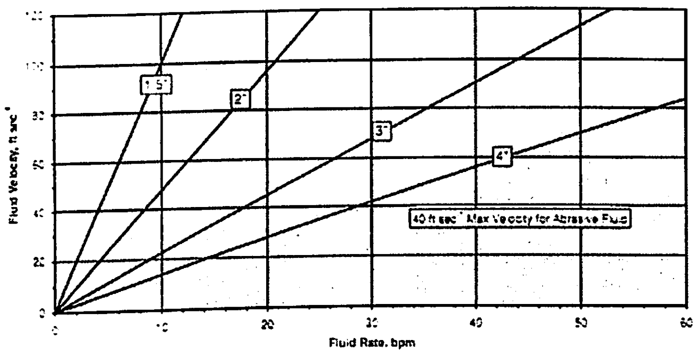


Chart showing fluid velocity against fluid rate for various nominal diameters of high pressure iron.

HIGH PRESSURE PUMPS

Most high pressure pumps used in hydraulic fracturing are of the triplex variety, although quintuplex pumps are becoming more popular. Triplex means that there are three pistons acting to pump the fluid, quintuplex means that there are five. These pistons are driven by a rotating crankshaft, as illustrated in Figure I.

Figures II and III show what happens whilst the pump is operating. Figure III shows the suction or inlet stroke of the cycle. As the plunger moves back towards the power end, fluid is pushed through the suction valve by the blender. The spring acting to close this valve requires 20 to 40 psi just to lift it up, so the blender must provide a boost pressure significantly greater than this in order to quickly fill the fluid end.

Figure III shows the power or discharge stroke. As the plunger moves away from the power end, the increased pressure in the fluid end causes the suction valve to close, and once this pressure is high enough, the discharge valve to open.

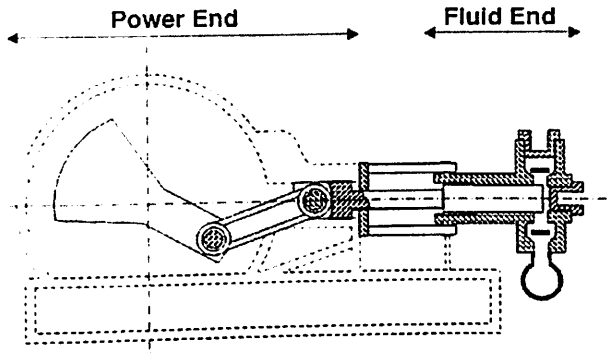


Figure I - Schematic diagram of a generic frac pump

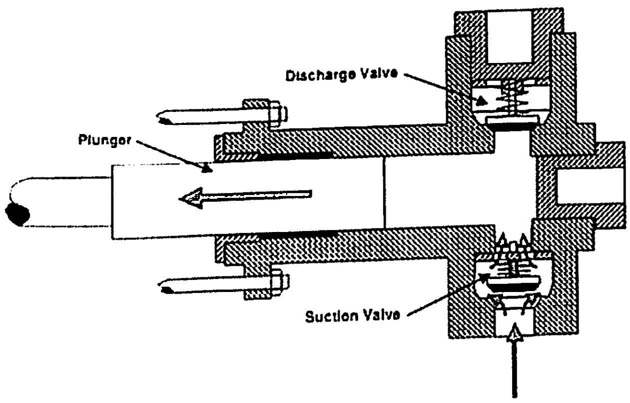


Figure II - Generic frac pump, suction stroke

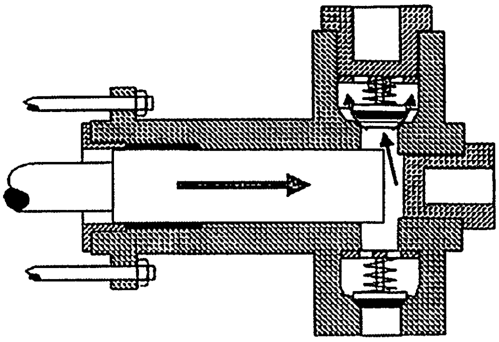


Figure III - Generic frac pump, discharge stroke

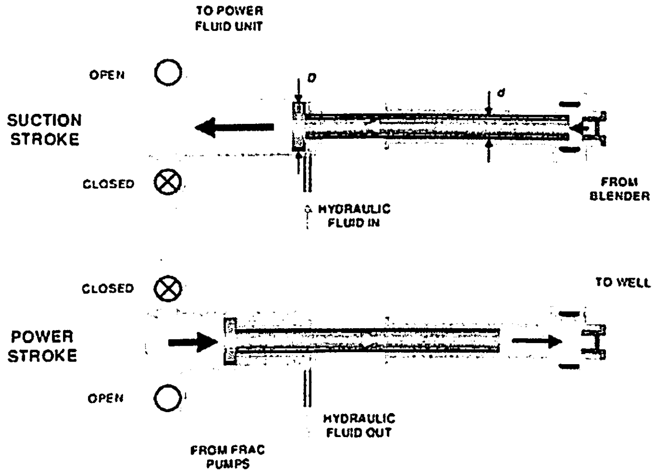
INTENSIFIERS

Intensifiers are devices that are used for pumping frac treatments for extended periods at high pressure and rate. They reply on conventional frac pumps to power them, and work on the principle that at constant power, high rate and low pressure is the same as low rate and high pressure.

At the power fluid end of the intensifier, the frac pumps supply power fluid at high rate and (relatively) low pressure. This acts to displace a large diameter piston down the power end. At the other end of this piston is a smaller diameter piston, which is mounted inside the downhole fluid end. This acts to pump the frac fluid at high pressure and (relatively) low rate, as illustrated in figure given below..

Suction Stroke – Hydraulic fluid is forced behind the power fluid piston to force the piston back. This allows the downhole fluid end to fill with frac fluid from the blender.

Power Stroke – The pressure on the hydraulic fluid is released. At the same time, the inlet valve from the frac pumps is opened, allowing the power end to fill with power fluid. This forces the piston down the power fluid end. At the other side of the intensifier, the frac fluid is forced out of the downhole fluid end at high pressure.



Schematic diagram of a generic intensifier

BLENDING EQUIPMENT

The blender is the heart of the fracturing operation. Although modern blending equipment is often highly automated, the blender operator (or Blender Tender) still retains one of the most critical positions on any location. Figure given below shows a generic schematic diagram of a frac blender.

The blender performs the following functions:-

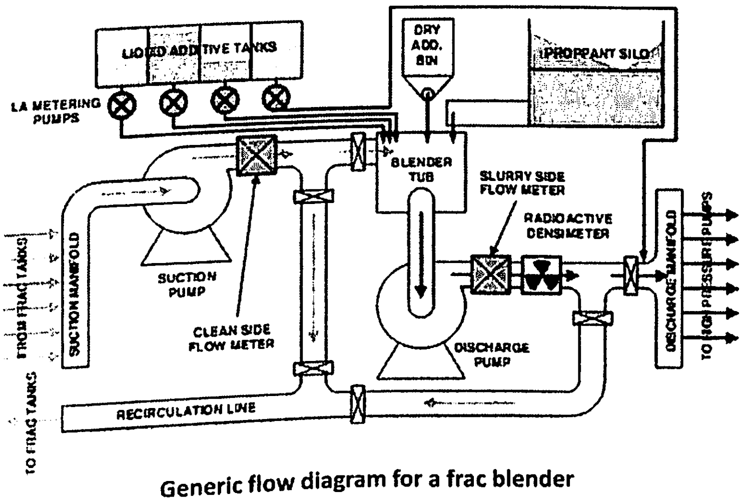
i) Pre-gelling tanks.

ii) Blending liquid and dry additives on the fly.

iii) Blending proppant on the fly.

iv) Providing supercharge for the high pressure pumps.

v) Metering and recording a variety of job critical parameters.



Generic flow diagram for a frac blender

THE WELLHEAD ISOLATION TOOL

The Wellhead Isolation Tool (WIT), often referred to as a "Tree Saver", is a device that allows treatments to be pumped at a STP higher than the maximum pressure rating of the wellhead. This allows treatments to be pumped at much higher rates than would normally be possible. The WIT does this by completely isolating the wellhead from the treating fluid, as illustrated in figures below.

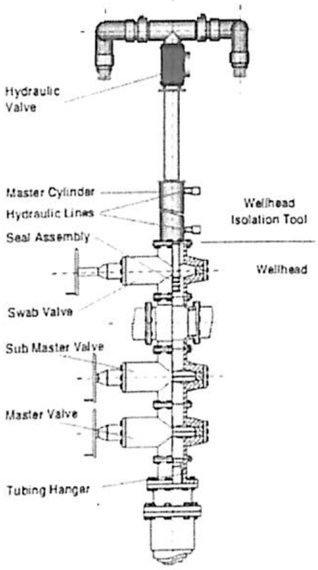
The tool is used in the following manner:-

- Prior to the treatment, the WIT operator obtains data for the type and size of wellhead top flange connection, the distance from the top flange to the tubing hanger, the tubing size and the tubing weight. This allows the WIT operator to assemble the stinger and seal assembly to match the wellhead.
- The wellhead master valve is closed, and any pressure between the master valve and the top flange is bled off.
- The WIT is assembled to the top flange.. Some WIT's are fitted with a master valve above the stinger (below the Tee section), whilst others require additional valves to be fitted.
- The WIT operator applies hydraulic pressure to the lower connection on the master cylinder, to ensure that the tool is fully extended, or stung out of the wellhead.
- The valves at the top of the WIT are closed and the tool is pressure tested.
- The wellhead master valve is opened and the WIT is exposed to wellhead pressure.
- The tool is stroked down by pumping hydraulic fluid into the top connection on the master cylinder.
- The stinger and the seal assembly are sized so that the seal assembly stings into the top of the tubing, at the point when the stinger is fully stroked into the well.
- The upper section of the WIT and the master cylinder are clamped together, so that hydraulic pressure is no longer required to keep the tool stung into the tubing.

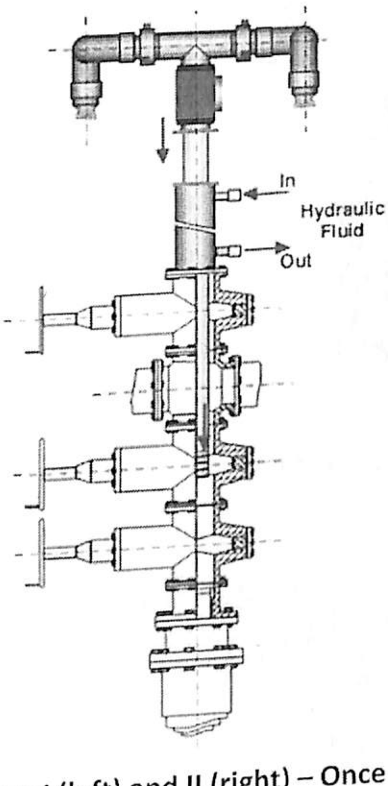
The WIT tool can be extremely useful, as it can be operated on a live well. This then eliminates the need killing the well and replacing the wellhead.

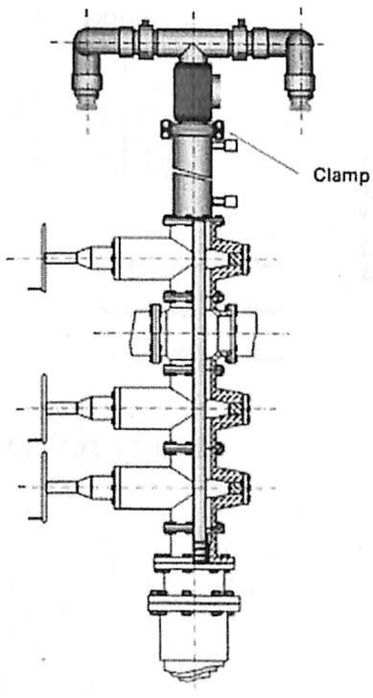
Use of the WIT on a live well is a very specialised process, requiring a trained operator. The tool can be very dangerous if not assembled or operated correctly.

The WIT is generally available in two main sizes, big and small. The small size is used for stinging into most tubing sizes, from 2-3/8" up to 4" or larger. The large sized tool is used for stinging directly into casing, with no tubing in the well.



Generic wellhead isolation tool rigged up to wellhead. The WIT is connected to the wellhead via the wellhead's top flange. At this point the wellhead master and sub master valves are closed, maintaining control of the well and allowing the frac lines and WIT to be pressure tested.



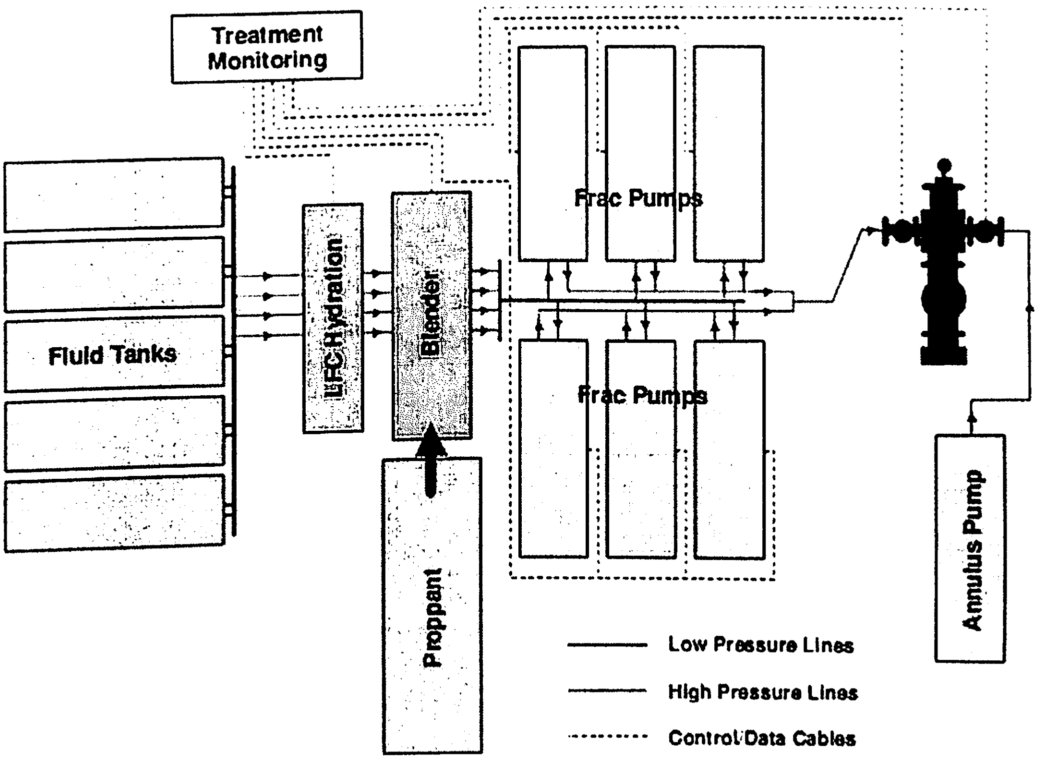


Figures I (left) and II (right) – Once the WIT has been connected to the wellhead and pressure tested (Fig I), the next stage is to close the valves of the frac lines (not shown – note that some WIT's have their own master valves) and open the master and sub master valves on the wellhead. One the wellhead is open, the stinger is stroked down into the top of the tubing by pumping hydraulic fluid into the master cylinder.

THE FRAC SPREAD – HOW IT FITS TOGETHER

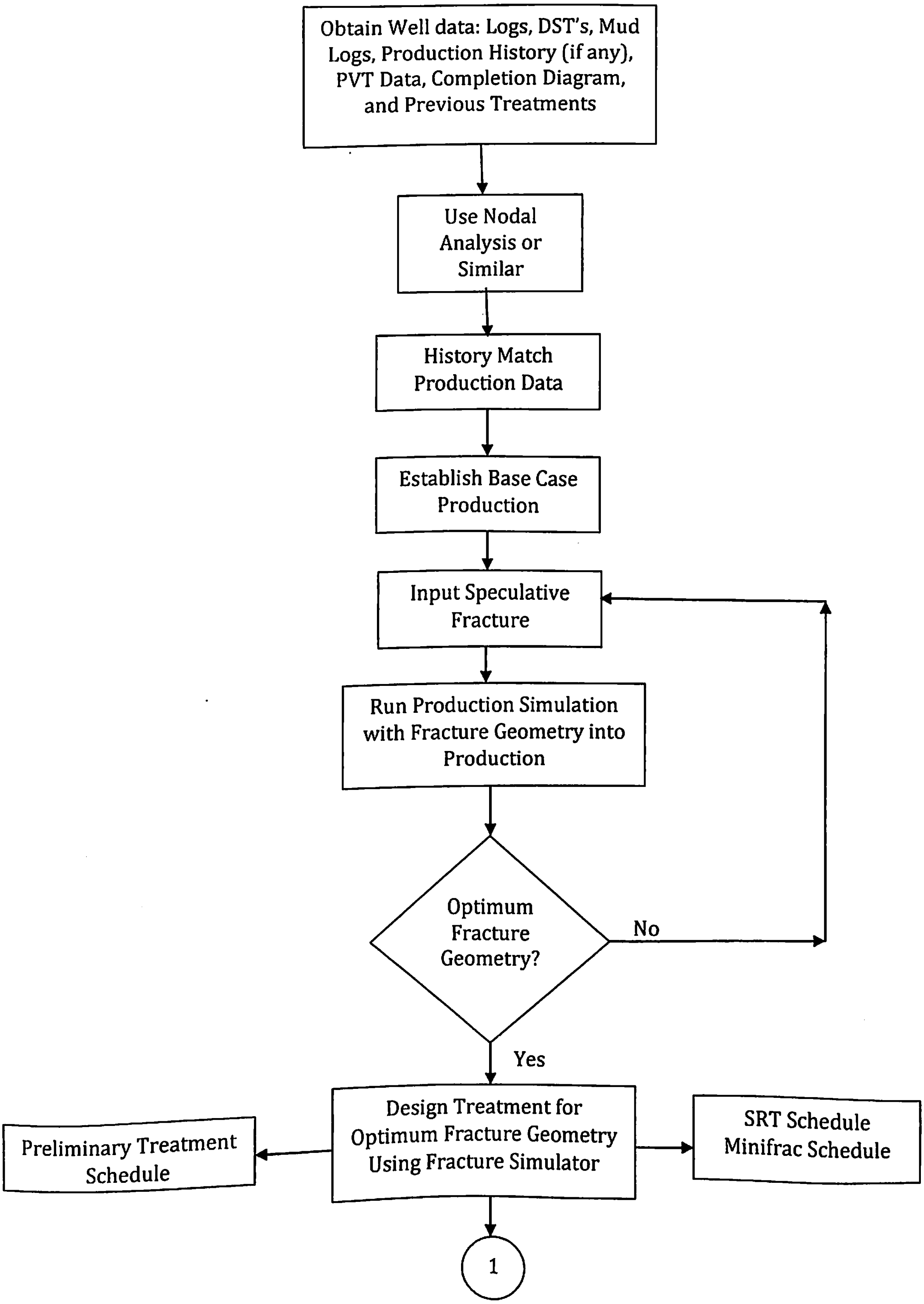
Figure given below illustrates how all the various components of the frac spread fit together. All frac spreads will basically look like this, although the size and number of components may vary. Some treatments will not use an LFC hydration unit, as the gel will be batch mixed prior to the treatment. Some treatments may use intensifiers, whilst some treatments ("batch" fracs, or Liquid Proppant fracs) may not have separate proppant handling equipment.

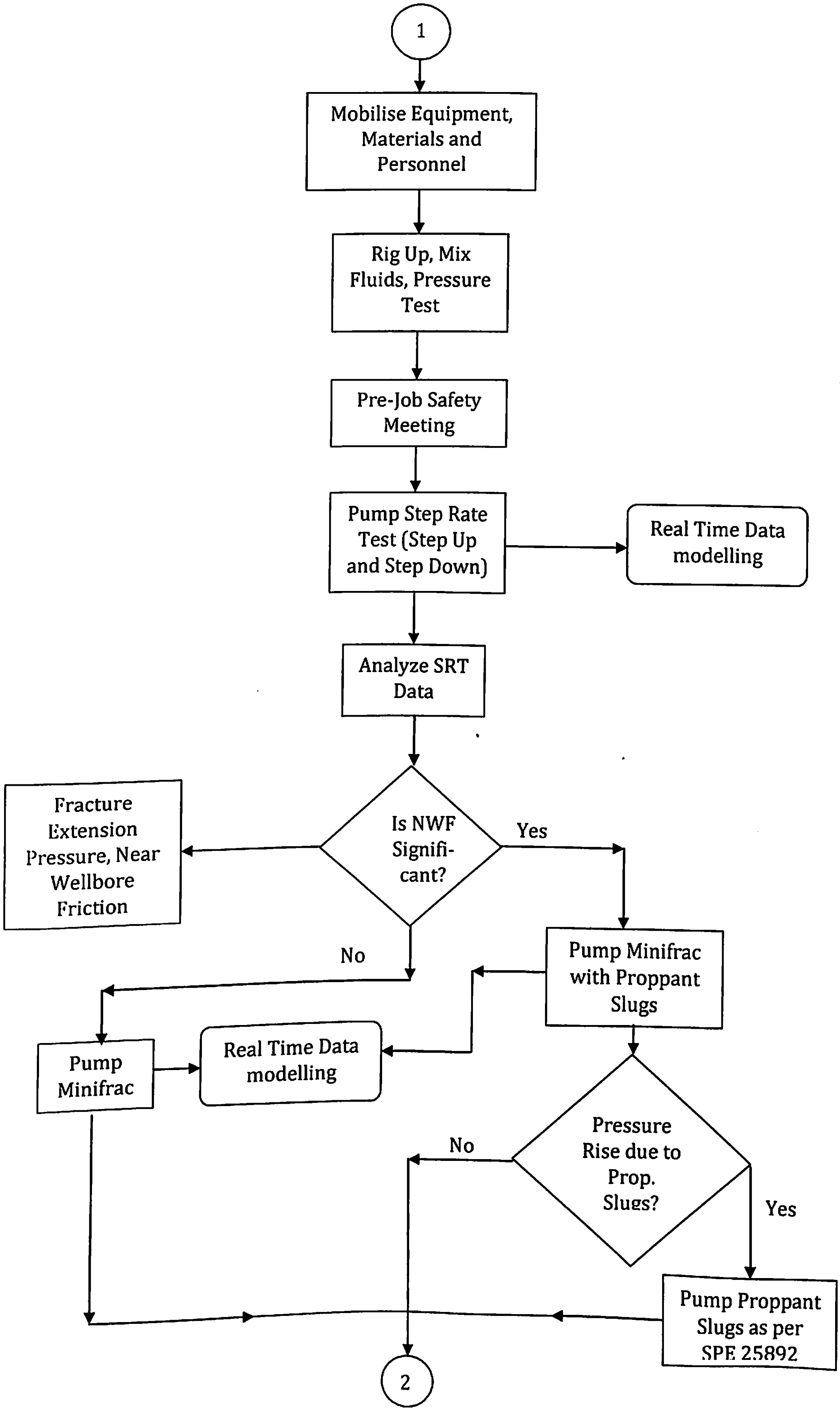
However, the basic process is the same, no matter what kind of treatment is being performed. Fluid (usually water) is moved from the storage tanks and is usually blended with gelling agents to increase its viscosity. It is then blended with the proppant and pumped down the well.

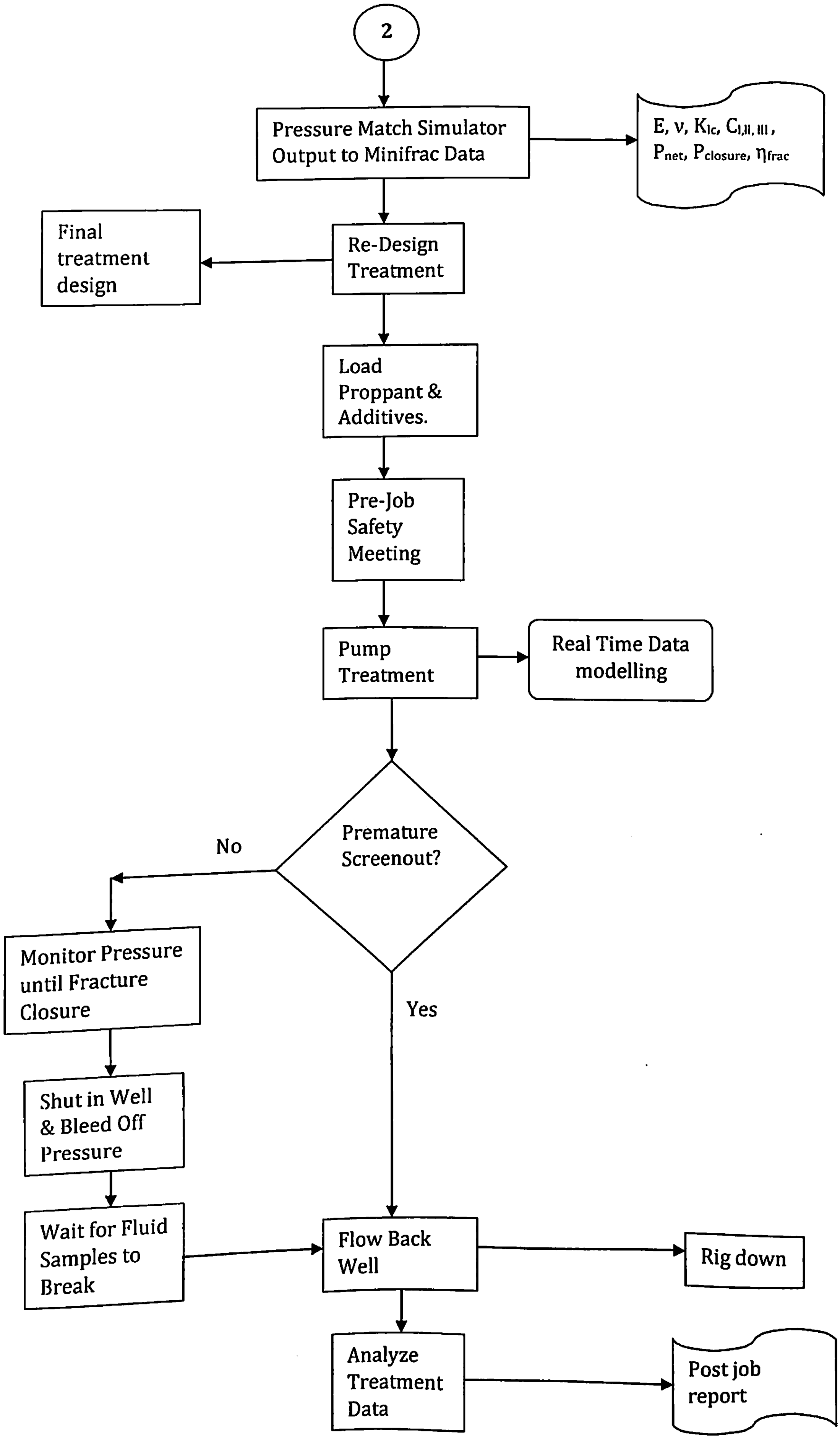


Schematic diagram of a frac spread

FRAC JOB FLOW-CHART




1
Mobilise Equipment, Materials and Personnel
Rig Up, Mix Fluids, Pressure Test
Pre-Job Safety Meeting
Pump Step Rate Test (Step Up and Step Down)
Real Time Data modelling
Analyze SRT Data
Is NWF Signifi-cant?
Fracture Extension Pressure, Near Wellbore Friction
Yes
No
Pump Minifrac with Proppant Slugs
Pump Minifrac
Real Time Data modelling
Pressure Rise due to Prop. Slugs?
No
Yes
Pump Proppant Slugs as per SPE 25892
2



2
Pressure Match Simulator Output to Minifrac Data
E, v, K_{Ic}, $C_{I,II,III}$, P_{net}, $P_{closure}$, η_{frac}
Final treatment design
Re-Design Treatment
Load Proppant & Additives.
Pre-Job Safety Meeting
Pump Treatment
Real Time Data modelling
Premature Screenout?
No
Yes
Monitor Pressure until Fracture Closure
Shut in Well & Bleed Off Pressure
Wait for Fluid Samples to Break
Flow Back Well
Rig down
Analyze Treatment Data
Post job report

The design and execution of a frac job can be broken down into 5 major steps:-

1. DATA COLLECTION

Collect as much data as possible on the well, and on treatments carried out on offset wells. This data includes, but is not limited to:-

i) Wireline logs. Useful for spotting boundaries between formations, high and low permeability and porosity, and also for spotting fluid contacts. Specialised logs can also give dynamic Young's modulus and Poisson's ratio, stresses and the quality of the cement bond. Get summary or evaluated logs whenever possible – there is no point in doing a full log analysis when somebody else has already done this. Also – if you are not confident with logs - a good first step is to mark where the perforations are, as these will be the productive intervals.

ii) Well test data. Useful for obtaining values such as reservoir pressure, permeability and skin factor. Again, get the report with the analysis already done. No one will expect you to be an expert well test analyst. These reports may also contain calculated data for porosity, viscosity, fluid saturation and compressibility.

iii) Completion diagram. Essential, as this will contain all the details you will need on the perforations, depth and sizes of tubing and casing strings etc.

iv) Wellhead diagram. Usually, all the Frac Engineer needs from this is a description of the top connection, so that the crew can have the appropriate crossover when they rig up to the wellhead. However, if a wellhead isolation tool is being used, a detailed diagram will be required.

v) Deviation survey. If the well is not vertical, the Frac Engineer will need to know MVD vs TVD for all formations, perforations and tubulars.

vi) Core data. If the well has been cored, this report may contain useful data on porosity, permeability and fluid saturation. In addition, the report may contain rock mechanical data and mineralogy (useful if the formation is suspected to be "water-sensitive").

vii) Core samples. If core samples are available, get hold of them and have them tested for Young's modulus and Poisson's ratio.

viii) Reservoir fluid samples. It is important to carry out compatibility testing between the frac fluid and the reservoir fluids. Problems are rare, but when they do occur they can ruin a well.

ix) Production data. Production data is useful for two reasons. First, this data is the basis for post treatment production forecasts. Secondly, a qualitative analysis should\ be performed to check for items such as water or gas coning and fines migration.

x) Produced sand samples. Essential if a frac and pack treatment is being designed, as a sieve analysis will be required to find the correct proppant size. However, getting a representative sample can be difficult. Surface samples tend to have a higher proportion of fines, as these are more easily carried out of the well. Bottom hole samples tend to be the other way around – high proportions of the fines have been\ carried away out of the well.

xi) Offset treatment data. Often, this is the most important and reliable source of data. Perform a complete analysis of these treatments, including a pressure match, if the data is available. If the data is reliable enough, this may even eliminate the need for a minifrac and step rate test.

xii) Location diagram. The Frac Engineer needs to know what size the location is, to ensure that all the equipment can be placed. If not, a smaller treatment needs to be designed. Especially important offshore, where additional factors such as crane maximum lift and deck loading must also be considered.

xiii) Other information, such as production logs (i.e. spinner surveys), temperature logs, caliper logs, mud logs, stress surveys, core flow testing, workover reports and drilling records can all provide useful information.

2. PRELIMINARY DESIGN

This stage uses all the data gathered in step 1 to produce a preliminary frac design. The initial step is to analyse the reservoir and production data and derive the optimum fracture geometry required. This step is best accomplished using nodal analysis. Then the fracture simulator is used to design a treatment to produce this fracture. Often, this design has to be tempered by considerations such as cost, mobilisation and equipment availability, so that the Engineer may go back and forth between the nodal analysis and the simulator several times. Unless the Engineer has good data from offset treatments, a step rate test and a minifrac will be required. The minifrac needs to be designed on a well by well basis. It should be pumped at the same rate as the preliminary frac design, using the same fluid and then displaced at the same rate using slick water. The volume of the minifrac should be at least equal to the anticipated pad volume. The minifrac fluid volume should be large enough to contact every formation that the actual frac will contact. This means that for tip screen out designs, the minifrac should be the same size as the pad, whereas for tight gas fracturing it must be considerably larger. Remember – it is much better to pump too much fluid than too little.

The minifrac is exactly what its name suggests – a small frac. In fact, it should be as close as possible to the actual treatment, in order to produce data as relevant as possible. Remember that if minifrac and step rate tests are being performed, there is no point in doing too detailed a design at this stage. The real design work will be done on location after these calibration tests. At this stage, what is required are reasonable estimates for the expected production increase, the quantity of materials and equipment that must be mobilised and the cost of the treatment.

Preliminary design work also includes designing the frac fluid. This often involves the use of Fann 50 (or similar) HPHT rheometers in order to ensure that the frac fluid has the right combination of stability and break.

3. CALIBRATION TESTS AND REDESIGN

Finally, the frac spread and crew gets mobilised and is rigged up on location. The next major step in the design and execution process is to perform the calibration tests (minifrac and step rate test). It is vitally important to get good data from these. Whenever possible, get bottom hole pressure data, either from a gauge or from a dead string.

For the step rate test, remember the following points:-

i) Get as many low rate steps as possible. Ideally, this means 4 steps below 2 bpm, although this is not always easy with big frac pumps. However, the more steps that can be taken before the frac starts to initiate, the better the results will be.

ii) Don't fiddle with the rate. When moving from one step to another, change the rate and then leave it alone. Getting a stabilised pressure is difficult enough without someone fiddling with the throttles. As long as the rate is approximately what it should be, that is good enough.

iii) Use the step rate test procedure as a guideline only, especially with regard to volumes. Getting a stabilised rate and pressure for each step is what we are after. Once this has been achieved, move on to the next step.

iv) It is important that the step rate test (step up variety) is performed on an unfractured formation. So either do the step rate test before the minifrac, or wait for a significant period of time after the minifrac is finished.

v) The opposite is true for the step rate test. An open fracture is needed before the step down begins, and the fracture must be open throughout the entire test. It is common to combine the two tests – step up and then step down again.

vi) Remember that the well must be full of fluid before the step rate test commences. If the well has to be filled up, do it at low rate to ensure no fracture forms.

For a minifrac, the following points are important:-

i) Keep the rate constant, even if this means pumping at a different rate than programmed. This makes the analysis easier and more reliable.

ii) Keep the fluid quality constant, again to make the analysis easier and more reliable. If necessary, gel up a couple of frac tanks, rather than mixing on the fly.

iii) Understand the wellbore fluid. Know its fluid properties and it's volume. Remember that this fluid will be injected into the fracture ahead of your carefully prepared fracturing fluid. So if you don't know the wellbore fluid, the careful preparation of the frac fluid is wasted. If necessary, circulate the well to completion fluid, or something similar before pumping the minifrac.

iv) Monitor the pressure decline. During this period, don't let the frac crew do anything, except drink coffee. It is all too easy for a silly mistake to ruin data collection. The Frac Engineer can also do his part by zero-ing out the rate on the fracturing monitoring computer – so that any fluid pumping by the blender does not show up as an erroneous downhole rate. Remember also to collect data for long enough – if data collection stops before closure (or closures) has happened, then the minifrac will have lost at least half of its value.

4. JOB EXECUTION

After all the planning and preparation has taken place, the actual treatment can sometimes take a surprisingly short period of time. During this period, the fate of the treatment no longer rests in the hands of the Frac Engineer. It is now up to the Supervisor and the rest of the frac crew to put the job in the ground as closely as possible to the revised treatment design.

Of course, on longer treatments, real-time redesign may be performed. In which case, the Frac Engineer may still have some influence on the treatment. However, usually it is time for the Engineer to sit back and let the crew get on with their job. Some Frac Engineers like to run the monitoring computer or check the fluid samples – both these occupations are useful and need to be performed. It is also important that the Frac Engineer stays in close contact with the Supervisor, just in case something unexpected happens.

5. POST TREATMENT ANALYSIS

There is no such thing as the perfect frac job. Every job has room for improvement, however slight. This applies to the Frac Engineer's job as well and the post treatment analysis is the way to find out what could have been done better.

Post treatment analysis comes in two parts:-

i) Analysing the pressure and rate data from the job. The best way to do this is with a pressure match, although don't spend too much time on this if you have no downhole pressure data. Results obtained from this will improve the success rate of future treatments.

ii) Assessing the production increase. Sometimes it is easy to loose sight of the objective of the entire process – to increase production. It is vitally important to keep track of the production of fractured wells. Remember that production over the first few days doesn't really count – we should be looking at the stabilised production several weeks after the treatment is performed. If production does not meet or exceed expectations, then the following three questions must be satisfied; Was the well a good candidate (i.e. reserves and pressure)? Was the optimum fracture placed in the formation? And were the post treatment expectations realistic?

The case history analyzed is of Cauvery basin, India. Hydraulic fracturing was done in three tight gas wells – CY-1, CY-2 and CY-4. Out of the three, CY-1 is considered in this report.

The well schematic, completions including spud date, target depth, hole sizes in different sections, casing details, tubing details and well head details and formation encountered of well CY-1are given below:

WELL COMPLETION

Location: CY-ONN-2002/1 block lies in the Ariyalur-Pondicherry depression of Cauvery basin.

Spud date: 21st August 2007

TD: 4210 m MDRT/ 4208.5m TVDRT/ 4187.5m TVDSS

Hole size:

26"	50 m (MDRT)
17 1/2"	903 m (MDRT)
12 1/4"	3014 m (MDRT)/3012.9 TVDRT
8½"	4210 m (MDRT) /4208.52 TVDRT

Casing details:

size	Type	ppf	Depth	Cement rise
20"	K-55, BTC	133	48 m	Surface
13 3/8"	K-55, BTC	72	900 m	250 m
9 5/8"	P-110, NSCC	53.5	3010 m	750 m
7"	P-110, NSCC	35	4208	2850 m

Wellhead: 15K FMC, Tested at 15000 psi

Tubing size: 3 ½", 12.7 ppf, 20 m above perforation

WELL SCHEMATIC

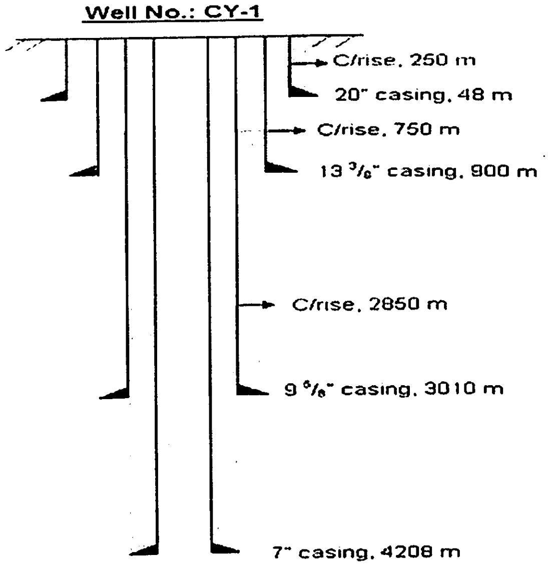


Fig: Well Diagram of CY-1

Formations Encountered In CY-1

Formation name	Formation top	Lithology
Nannilam	1869 m TVD	Claystone with interbedded unconsolidated Sand and Sandstones and traces of limestone
Kudavashal Shale	2563 m TVD	Claystone with interbedded sandstones at the bottom of the section and traces of limestone
Bhuvanagiri	3160 m TVD	Predominantly consists of massive Sandstone and thin streaks of claystones.
Sattapadi	3532 m TVD	Predominantly consists of massive Sandstone and thin streaks of claystones
Andimadam	3863 m TVD	Consists of intercalations of Claystone and Sandstones.

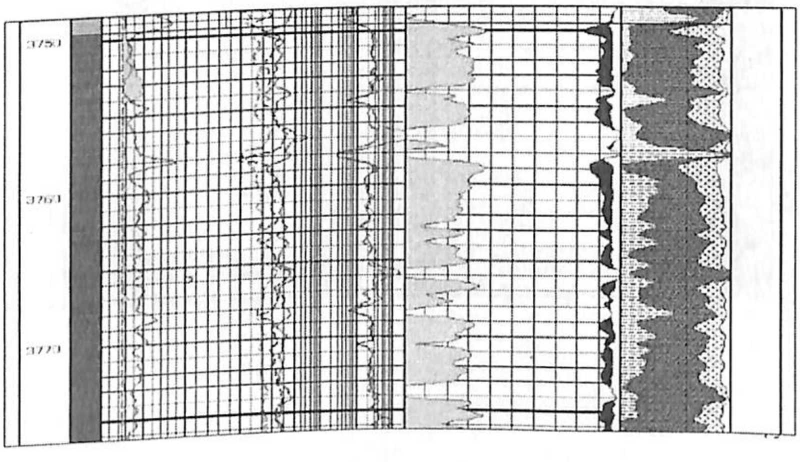
WELL TEST HISTORY

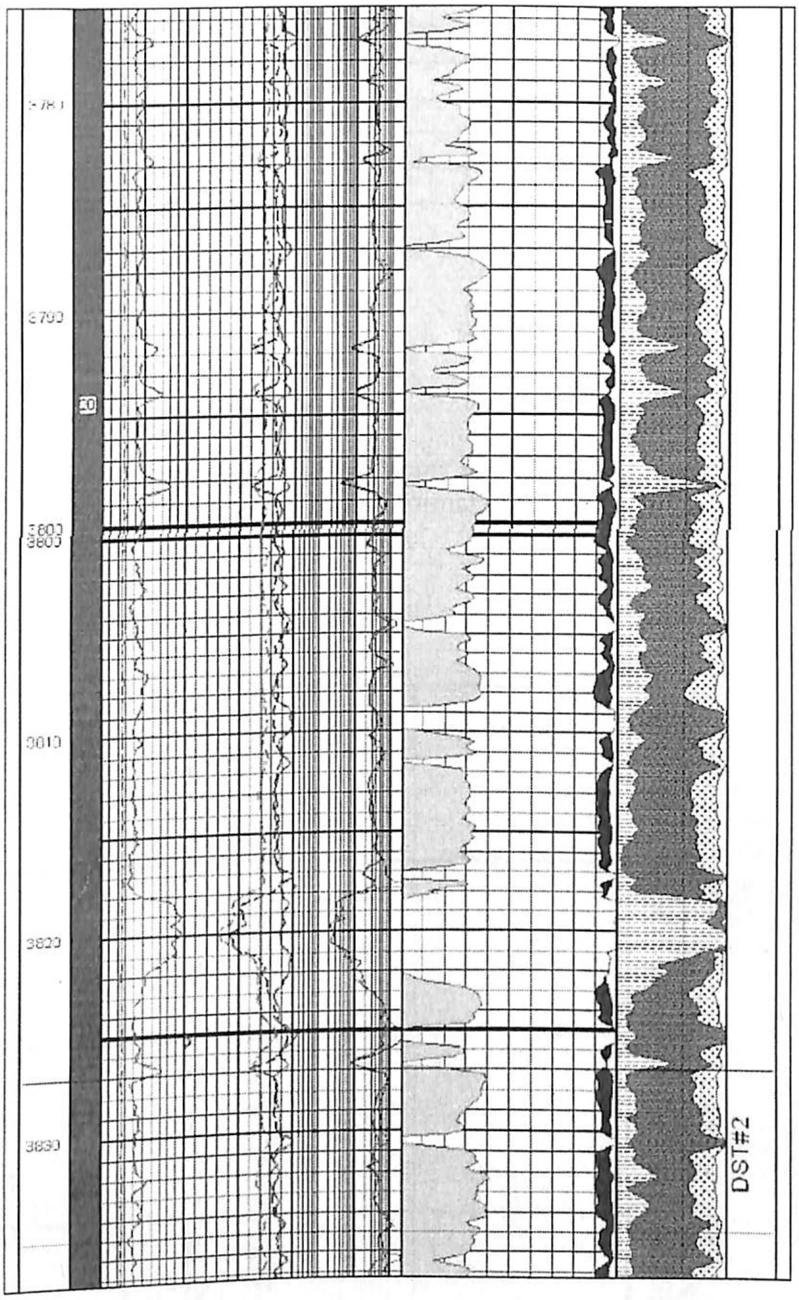
DST was done in CY-1 in Sattapadi and Andimadam formations. The details of the DST are given in the following table:

DST-1	Conducted in Andimadam formation within the interval of 3944- 3950 MD.The well flowed gas at 0.035 MMSCF/D through 16/64" choke and produced 10 bbls of condensate (Specific gravity .79, 480 API)
DST-1A	Conducted in Andimadam formation again within the intervals of 3944-3950m, 3953-3956m, 3959-3965m, 4005-4010m and 4016-4020m MD. The well flowed Gas at 0.021MMSF/D through 16/64" choke.
DST-2	Conducted in Sattapadi formation within the intervals 3827-3835m and 3845-3861m MD. The well flowed gas at 0.034MMSCF/D through 12/ 64" Choke and approximately 9 bbls of 360 API was recovered during reversing out

IDENTIFICATION OF TARGET ZONE:

The reservoir porosity and hydrocarbon saturation in various formations of CY-1 were evaluated from the log reports. Based on the logs evaluation the Sattapadi formation in this well is having gas saturation in the range of 40–70% and hence, identified for hydro-fracturing. Sattapadi formation is encountered in 3532–3863 m. The logs of various sections of the Sattapadi formation are given in the following figures:




3790
3800
3810
3820
3830
DST#2

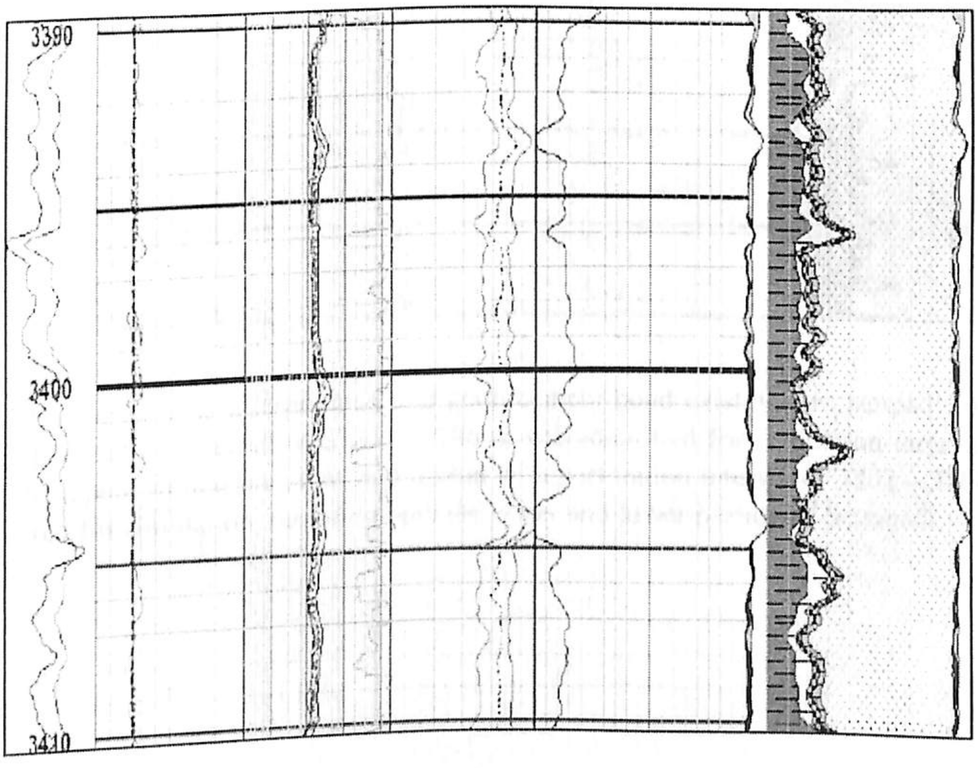
The lithology and reservoir properties of layers above and below are given in the following table:

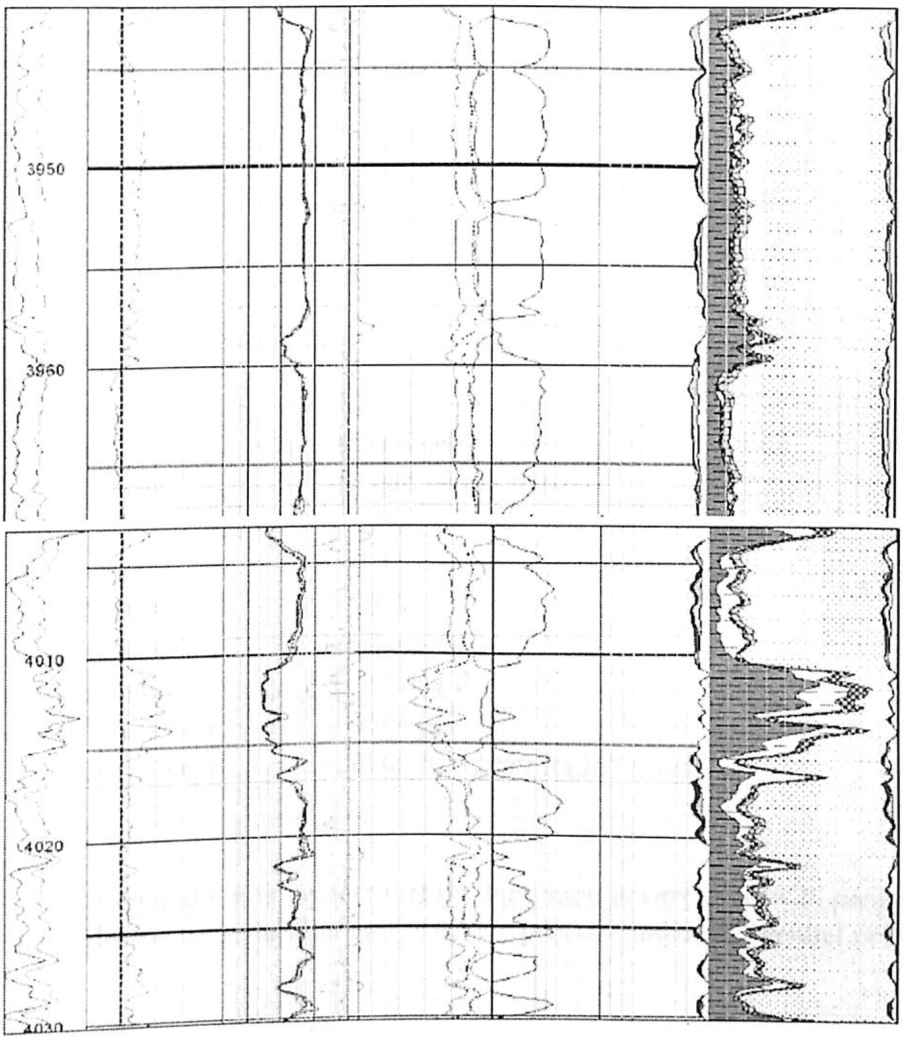
Formation	Depth top, m	Lithology	Φ, %	Sg, %
Sattappadi	3721	SST	10	50
	3725	Silty SST	8-36	10-50
	3738	Shale		
	3750	SST	6-18	40-75
	3817	Shale		
	3824	SST	4-12	60-80
	3840	Shale		
	3845	SST		

Bottom hole temperature : 2530F

Reservoir pressure : 9554 psi

The cement bond is not adequate for fracturing operation in Bhuvanagiri and Andimadam formations. The CBL of Bhuvanagiri and Andimadam formations is given in figure below.





As per the CBL records, it is interpretated that good cement bond exist against sattpadi formation. Therefore, the perforation interval of 3781 – 3786 m was identified for simulation targeting upper portion of the Sattapadi formation. A second option with perforation interval of 3802 – 3808 m, can also be considered for simulation, targeting both the upper and lower portion of Sattapadi.

FRACTURE OPTIMIZATION AND JOB DESIGN

Design basis:

A. Well completion:

o	Drilled hole	: 4210 m
o	Hole size	: 8.5 in
o	7" casing, p-110, 35ppf	: 4207 m
o	Tubing, 12.7ppf	: 3755 m
o	Packer	: 3755 m
o	Perforation, 6 spf	: 3781-3786 m

B. Reservoir parameters:

o	Formation	: Sattapadi
o	Reservoir type	: Tight Gas sandstone
o	Porosity	: 10%
o	Permeability	: 0.02 mD
o	Avg. Gas saturation	: 40%
o	Gross/Net pay	: 68 m / 59 m
o	Reservoir temp	: 253 deg F
o	Reservoir pressure	: 9544 psi
o	Reservoir drainage	: 2000 ft X 2000 ft (367 acres)

From the above data and information, it is evident that the formation is very tight with permeability 0.02 mD. However, the hydrocarbon saturation and reservoir pressure indicate potential production after fracturin.

Design process:

The simulations for optimization and job design have been carried out by the state of the art fracturing simulator "FRACPRO". The simulator consists of various modules viz. reservoir simulation, fracture optimization, hydraulic fracture simulation etc. The reservoir simulation module was used for estimating the production prediction of a fractured as well as un-fractured well. The fracture optimization module was used for optimization of the treatment size based on the production scenario, NPV and return on investment. The fracture simulation module was used for designing the optimized treatment for generating the best optimum schedule, estimating the requirement of fracturing fluid, predicting the treating pressure, horse power requirement and predicting the fracture dimensions and conductivity.

The result of process in case I (perforation interval 3781-3786) is tabulated below:

PARAMETERS	UN FRAC	FRAC
Initial HC rate, MscfD (10 days) MscmD	**849** 24.1	**5216** 149
Final HC rate, MscfD (20 yrs) MscmD	**652** 18.6	**1831** 52.3
Cum prodn, MMscf MMscm	**4812** 137.7	**15300** 437.1
HC Recovery, %	**11**	**34.8**
ROI, %	**72**	**300**

The result of process in case II (perforation interval 3802-3806) is tabulated below:

PARAMETERS	UN FRAC	FRAC
Initial HC rate, MscfD (10 days) MscmD	**849** 24.1	**8977** 256.5
Final HC rate, MscfD (20 yrs) MscmD	**652** 18.6	**3121** 89.1
Cum prodn, MMscf MMscm	**4812** 137.7	**26141** 746.8
HC Recovery, %	**11**	**35.1**
Return on invest, %	**72**	**640**

The comparison of HC rate, Cumulative Production, recovery and payback period in case-I and case-II are tabulated below.

Parameters	Case-I	Case-II
Perforation Interval, m	3781-3786	3802- 08
Gross/Net Pay, m	68/59	113/100
Initial HC rate (10 days), MscfD	5216	8977
Final HC rate (20 yrs), MscfD	1831	3121
Cumulative Production, MMscf	15300	26141
Recovery, %	34.8	35.1
Return on investment, %	300	640
Payback period, days	1005	510

From the study it is evident that the production rate and cumulative production is much better in case-II. Therefore a 100 MT size job considering perforation interval of 3802 – 08 m would be the better choice for this well.The details of fracturing job design are given below:

FRACTURE STIMULATION

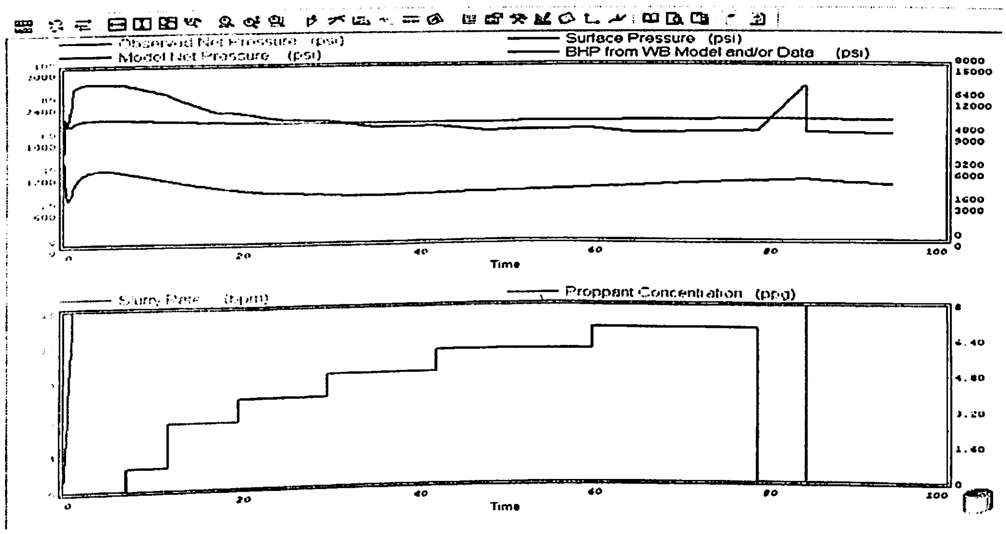
FracPRO was run on fracture simulation mode for treatment design with following wellbore and lithology options:

- Model Wellbore and Perforations
- Complete Wellbore Configuration
- Lithology Based Reservoir
- Vertical Fracture
- Allow Fracture Growth at Shut-In
- Proppant convection

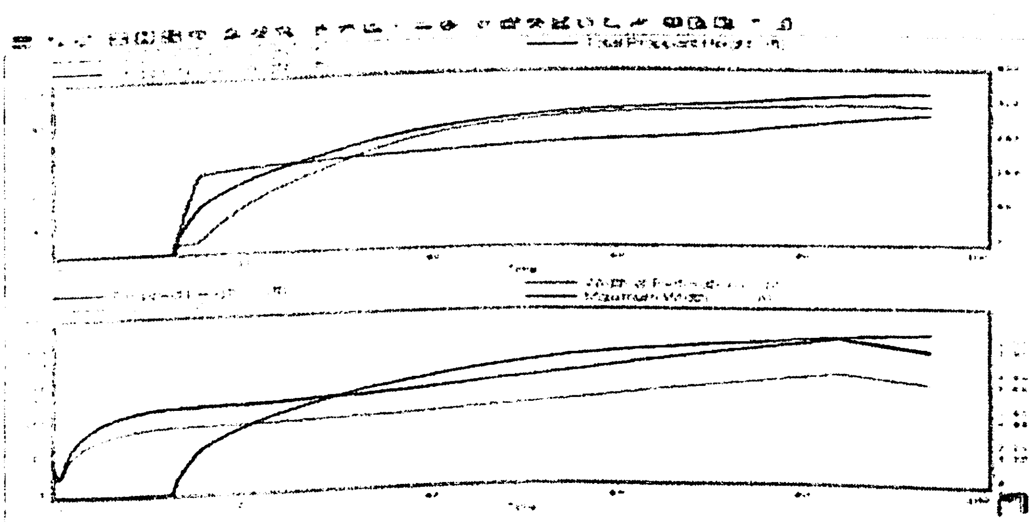
Reservoir simulation module was run using fracture simulation data for production prediction and economic evaluation. The various output parameters of the simulation are given in the table below.

Total proppant	**100.8 Tons**	Fracture half length	218 ft
Scheduled clean vol.	1238 bbls	Propped half length	210 ft
Schedule slurry vol.	1420 bbl	Fracture upper height	211 ft
Max Surface Pressure	7260 psi	Fracture lower height	136 ft
Max BH Pressure	10500 psi	Total fracture height	347 ft
Avg. Hydraulic Power	2303 hp	Propped fracture height	335 ft
Fracture efficiency	0.55	Max width at well	0.81 in

The pressure match plots are given in the figure below.



The fracture and propped dimensions are given in the figures below:



Average proppant concentration and dimensional conductivity are 2.0 lb/ft2 and 1279 respectively. The treatment schedule is tabulated below:

Stage	Elapsed Time (min:sec)	Fluid Type	Clean Volume (bbls)	Proppant Conc. (ppg)	Slurry Rate (bpm)	Proppant Type
1	1:06	YF540HT W/10 LB/K J	10.0	0 - 0	1.0 - 17.0	
2	6:59	YF540HT	100.0	0	17.00	
3	11:33	YF540HT	75.0	1.00	17.00	SntBaux2040
4	18:02	YF540HT	100.0	3.00	17.00	SntBaux2040
5	28:04	YF540HT	150.0	4.00	17.00	SntBaux2040
6	41:51	YF540HT	200.0	5.00	17.00	SntBaux2040
7	59:36	YF540HT	250.0	6.00	17.00	SntBaux2040
8	78:34	YF540HT	260.0	7.00	17.00	SntBaux2040
9	84:04	YF540HT	93.6	0	17.00	
10	89:04	SHUT-IN	0	0	0	

PROPOSED COMPLETION FOR HYDRAULIC FRACTURING:

Well head and X Mass tree: 15000 psi

Casing:

- Size & grade : 7", P-110, 35 ppf
- Collapse resistance : 13,010 psi
- Internal yield : 13,700 psi

Perforation:

- Perforation Interval : 3802- 08 m
- 6 spf, preferably 60 deg phasing with big hole diameter.

Packer:

- Type : Permanent packer
- Packer depth : 3780 m
- Pressure rating: 15000 psi

Tubing:

- Size & grade : 3-1/2 in, P-110, 12.7 ppf
- Collapse resistance : 17,940 psi
- Internal yield : 20,630 psi

CONCLUSION

Hydraulic fracturing is one of the best well stimulation techniques to enhance oil well productivity or injectivity. It provides excellent result for stimulation jobs than other methods. It is widely used method for Tight Formations, CBM Treatments and Shale Gas Formations. Today, thousands of these treatments are pumped every year, ranging from small skin bypass fracs at $20,000, to massive fracturing treatments that end up costing well over $1 million. Many fields only produce because of the hydraulic fracturing process.

The process consists of choosing the right formation or well, fluid system, proppants, and designing the process for the well chosen. Fracturing – as with any other operation performed on an oil or gas well – has to be economically justified. That is to say, the increased revenue generated by the treatment must satisfy economic criteria set by the operating company.

The designing of fracturing process includes selecting the fluid, perforation, maximum pressure at which pumping can be done, fracture monitoring, simulation and post treatment evaluation. A flowchart defining the whole process has been displayed in the report.

Hydraulic fracturing in itself is a complex process but increasing energy demand and increasing oil cost has resulted in high employment of this technique throughout the whole world. Though it started as acid fracturing which could be only done in carbonate rocks, today it is also known as hydraulic fracturing or proppant fracturing as other fluids came into existance.

As this technique increase the natural permeability of the formation by several folds, it can be employed in formations whose permeability is very low . Shale rocks which were considered non- producing rocks, today has a become a major source of energy.To produce from shale, two complex techniques are used on large scale- horizontal drilling and hydraulic fracturing.

Though this technique had been studied for various years, further research needs to be done to make it more economical and environmentally sustainable as it will be used more extensively in the future as countries have started producing from tight formations like shale.

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