

CHAPTER 1

INTRODUCTION

Hydraulic fracturing has been used in wells having low to moderate permeability to increase the performance. In certain situations fracturing cost of a well may reach to 100% of the well drilling cost (Economides *et al.* 1989). Therefore, a number of factors must be considered to optimize a particular treatment.

Two types of hydraulic fracturing techniques in use are acid fracturing and propped hydraulic fracturing. Both types of treatments create a high conductive path from deep in to the reservoir to the wellbore.

In the propped hydraulic fracturing a viscous fluid is pumped in to the completion at a sufficiently high pressure into completion interval so that a two wing hydraulic fracture is formed. This fracture is then filled with a high conductivity proppant which maintains the high conductive path to the wellbore and keeps the fracture open after the treatment. The propped fracture can have a width of 5mm to 35mm and a length of 100 m or more which depends on the design technique and size of the treatment (Davies. 2007). Hydraulic fracturing can be applied to both clastic and carbonate reservoirs (Davies. 2007). Propped hydraulic fracturing is aimed to raise the well productivity by increasing the effective wellbore radius of wells completed in low permeability reservoirs.

The radial well inflow equation is:

$$Q = \frac{kh(P_e - P_{wf})}{141.2\beta_o\mu_o \left[\ln \left[\frac{r_e}{r_w} + S \right] \right]} \quad (1.1)$$

Where,

$Q \equiv$ Volumetric flowrate (bbls/day)

$k \equiv$ Permeability (md)

$h \equiv$ Formation thickness (ft)

$\beta_o \equiv$ Oil formation volume factor (rb/stb)

$\mu_o \equiv$ Oil viscosity (cp)

$P_e \equiv$ Reservoir pressure (psi)

$P_w \equiv$ Wellbore flowing pressure (psi)

$r_e \equiv$ External radius (ft)

$r_w \equiv$ Wellbore radius (ft)

$S \equiv$ Skin

As can be seen in the above equation (1.1), that flowrate can be increased by:

- i. Increasing formation flow capacity (k.h)
- ii. Bypassing flow effects that increase the skin (s)
- iii. Increasing the wellbore radius (r_w) to an effective wellbore radius (r_w')

Fracture may increase the effective formation height (h), connect to a high permeability formation and increase wellbore radius (r_w) to effective wellbore radius (r_w'). Where effective wellbore radius (r_w') is a function of the fracture length (L_f). If a fracture has infinite conductivity then the wellbore radius can be expressed as:

$$r_w' = L_f/2 \quad (1.2)$$

Thus high conductivity fractures allow fluids to flow to the well whose effective radius has been enlarged to a value equal to half length of the single wing fracture length. Since hydraulic fracture stimulation is required for the economic development of low permeability reservoirs, there should be certain guidelines for the selection of the hydraulic fracture treatment. Hydraulically fractured well will have a negative skin and great production rate. However, propped hydraulic fracture well stimulation should only be considered when meeting the following cases (Davies. 2007):

- i. Well is connected to adequate producible reserves
- ii. Reservoir pressure is high enough to maintain flow
- iii. Production system can process the extra production
- iv. Professional, experienced personnel are available for the treatment design and execution.

There are minimum criteria for the treatment for the hydraulic fracturing treatment and is summarized in **Table 1.1** below (Davies. 2007):

Table 1.1: Minimum hydraulic fracturing candidate well selection screening criteria (Davies. 2007)

Parameter	Oil Reservoir	Gas Reservoir
Hydrocarbon Saturation	>40 %	>50 %
Water Cut	<30 %	<200 bbls/MMscf
Permeability	1 – 50 mD	0.01 – 10 mD
Reservoir Pressure	<70 % depleted	Twice abandonment pressure
Gross Reservoir Height	>10 m	>10 m
Production System	20 % Spare Capacity	

Since stated before that hydraulic fracturing treatment is costly and in some cases reaches to well drilling cost. Therefore, it is necessary for the candidate well to fulfill the minimum criteria required. **Table 1.1** lists minimum hydrocarbon saturation, reservoir pressure, gross reservoir thickness, maximum water cut and permeability range for oil and gas wells. A well will therefore be fracture stimulated once above conditions have been satisfied.

Inflow performance of hydraulically fractured well is controlled by the dimensionless fracture conductivity (F_{cd}) (Davies. 2007).

$$F_{cd} = \frac{k_f \times W}{k \times L_f} \quad (1.3)$$

Where,

$k_f \equiv$ Fracture permeability (md)

$W \equiv$ Conductive fracture width (ft)

$k \equiv$ Formation permeability (md)

$L_f \equiv$ Conductive fracture single wing length (ft)

Therefore, fracture conductivity can be increased by increasing proppant permeability, increasing fracture width and minimizing damage to the proppant pack from the fracturing fluid. When hydraulic fracturing treatment is carried out increased production is usually represented by “Folds of Increase (FOI)” (Davies, 2007).

$$FOI = Q_f/Q_o \quad (1.4)$$

Where,

$Q_o \equiv$ Well production after carrying out hydraulic fracturing treatment

$Q_f \equiv$ Well production after carrying out hydraulic fracturing treatment

As stated earlier that cost of treatment can increase to 100 % of the well drilling cost (Economides *et al.* 1989) therefore, optimization of the fracture treatment is very important. Therefore, first parametric studies is carried out, allowing the variation of execution variables and then detection of differences in their respective design “Net Present Value” (NPV) (Economides *et al.* 2008).

Following issues are recommended to be evaluated during the design (Davies, 2007):

- i. Transport of the proppant to the fracture tip

- ii. Settling of the proppant due to inadequate fracturing fluid viscosity
- iii. Creation of the required proppant pack width and degradation of the fracturing fluid to minimize permeability damage to the proppant and the formation
- iv. Containment of the hydraulic fracture to the pay zone.

Table 1.2 lists some of the main variants in fracturing technology for vertical wells and their areas of application.

Table 1.2: Treatment selection guidelines (Davies, 2007).

Reservoir Type	Treatment Applications	Candidate Well	
		Skin (S)	Permeability (K)
Sandstone or Carbonates	Conventional propped fracture	High / Low	Low
	Skinfrac	High	Medium
Naturally fractured reservoirs filled with Calcite Cement	HCL acid pumped near or above Fracture Propagation Pressure (FPP)	Low	Low (Matrix)
Inhomogeneous Carbonates	HCL acid pumped above FPP	High / Low	Low
Homogeneous Carbonates	WISPER – Pump visious Pad follow by HCL Acid. Both above FPP	High / Low	Low
	CFA – Pump visious Pad above FPP, follow by HCL acid just below FPP	High / Low	Low

Propped hydraulic fracturing is applicable to both sandstone and carbonate formations. Proppant transport and hydrocarbon fracture containment within the pay zone are key issues to be addressed during the treatment design (Davies. 2007).

Skin fracing which is the creation of short but highly conductive fractures is applied to medium permeability reservoirs ($K > 100$ mD). In naturally fractured carbonate

formation increased conductivity is achieved by pumping hydrochloric acid in the formation.

Acid fracture treatment can be applied to an inhomogeneous carbonate formation. These naturally occurring inhomogeneities will ensure that some parts of rock will react more quickly with acid than others, resulting in a deeper etching of the fracture wall at this point. Providing the formation is strong and inhomogeneous enough, the (deeper) etched channels will remain open after the treatment is finished, forming a conductive flow path to the wellbore (Davies. 2007).

Soft homogeneous carbonates (e.g. chalks) require the artificial creation of the necessary inhomogeneities.

1.1 PROBLEM STATEMENT

Wells in low to moderate permeability zones are treated for hydraulic fracturing to increase their performance. Hydraulic fracture treatment is costly which might equal to 100% of well cost. It is necessary to optimize a particular hydraulic fracture treatment. Although the job is always designed to get maximum benefit, there are operational problems which can cause failure in hydraulic fracture treatment. Main challenges in hydraulic fracturing of a well are:

- Fracture Containment
- Fracture Conductivity

Failure to contain the fracture and achieving desired conductivity will not only give less than expected production but also sometimes cause decline in production. There is a need to study root causes or elements that caused problem in fracture containment and fracture conductivity.

1.2 PROJECT OBJECTIVE

The objective of this study is to:

- Gather information from reported field cases on limitations of hydraulic fracturing treatment applied to low permeability formations.
- Recognize key challenges faced in hydraulic fracturing treatment in low permeability reservoirs
- Propose possible solutions for hydraulic fracturing in low permeability reservoirs.

1.3 SCOPE OF WORK

1. Literature review
2. Identification of key challenges
3. Case studies on controlling identified challenges.
4. Conclusion of the study
5. Recommendations and suggestions.

CHAPTER 2

LITERATURE REVIEW

2.1 INTRODUCTION

The Hydraulic fracturing technique is one of the major well stimulation developments. This technique was first introduced to the industry by J.B Clark (1949) of Stanolind Oil and Gas Co. in 1948. After that the technique was extended very fast and by the end of 1955 more than 100,000 hydraulic fracturing treatments have been performed (Economides *et al.* 1989).

This technique itself is mechanical and is related to three other phenomena such as:

- i. Pressure parting in water injection wells
- ii. Lost circulation during drilling
- iii. Breakdown of formation during squeeze cementing operations.

All of above three shows opening of the formation by applying pressures in the wellbore. The most popular interpretation of this mechanism has been that the pressure has parted the formation along the bedding plane and lifted the overburden, notwithstanding the fact that in the great majority of cases where pressures were known they were significantly less than those due to the total weight of the overburden as determined from its density.

Prior to 1948, this prevalent opinion had already been queried by Dickey and Andresen (1945) in a study of pressure parting and (Walker, 1946 and 1949) who in studies of squeeze cementing pointed out that the pressures required were mostly less than those of the overburden and inferred that the fracture should be vertical (Walker, 1949). Later on

Howard and Fast (1950) and Scott, Bearden and Howard (1953) reported that the entire weight of the overburden is not needed to be lifted to produce horizontal fractures instead it is only necessary to lift an effective overburden, relatively a smaller pressure. (Hubbert, 1953) discussed the paper by Scott and associates and pointed out that normal state of stress underground is one of unequal principle stresses and in tectonically relaxed areas the least stress should be horizontal. Therefore, in most cases fracturing should be possible with pressure less than that of the overburden and moreover fractures should be vertical.

2.2 PRE-TREATMENT DATA REQUIREMENT

There are three technical areas that need to be addressed when preparing a stimulation design; well potential, fracture geometry and orientation and treatment fluids and proppants. Proper evaluation of these areas requires the knowledge of various rock and fluid properties. The four common sources of information include geology, core testing, geophysical and petrophysical logging, and dynamic (flowing) downhole testing (Economides *et al.* 1989).

Results of hydraulic fracturing treatments varied from extremely successful to extremely disappointing failures. The failures and economics aspects require the need to critically study the stimulation process (Veatch, 1986: Murphy and Carney, 1977).

2.2.1 Formation Flow Potential

It is imperative that the present well potential be critically evaluated prior to the job. The important data and parameters that fall in this category include:

- Porosity (Hydrocarbon, Water)
- Saturation (Hydrocarbon, Water)
- Permeability (Absolute, Relative)
- Petrographic description of minerals
- Reservoir pressure
- Gas-Oil and Water-Oil Contacts

For the formation flow potential only pay zone data is required while to perform Leakoff studies, one needs to gather data from the pay zone as well as the bounding formation rocks (Economides *et al.* 1989).

2.2.2 Fracture Geometry

Figure 2.1 illustrates ideal propped fracture geometry. Hydraulic fracturing treatment creates a highly conductive path from deep into the reservoir upto the wellbore. As seen earlier in equation (1.3) that parameters, L_f (fracture half length), r_w' (effective wellbore radius), w (fracture width), p_e , r_w (external pressure and radius respectively) and k_f is (fracture permeability) combines to create fracture conductivity.

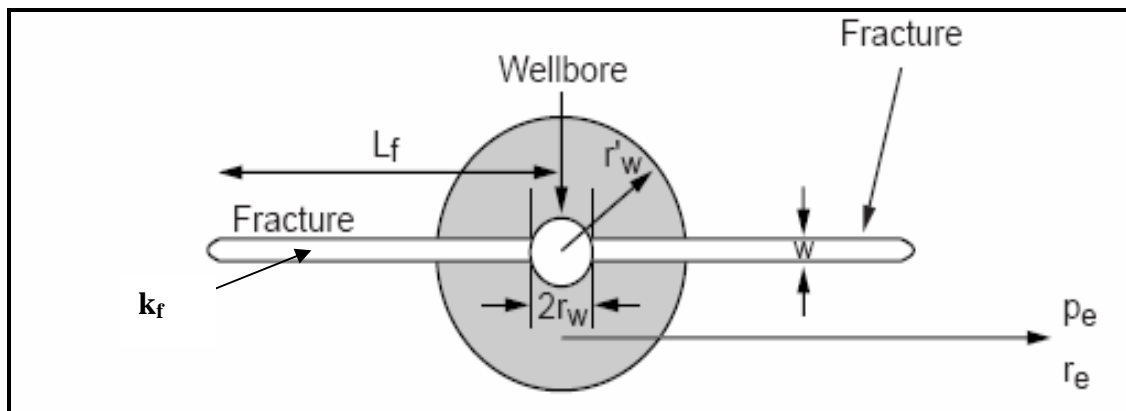


Figure 2.1: Propped hydraulic fracture geometry (Davies. 2007)

2.3 TREATMENT FLUID AND PROPPANT EVALUATION

There are three primary areas that need to be addressed when optimizing fluid and proppant requirement.

- The ability of the treatment fluid to carry the proppant to a certain fracture penetration length
- Fluid loss control

- Assurance of minimum impairment of the created fracture flow capacity and fracture face permeability caused by the treatment fluid.

2.4 FRACTURING FLUID

The fracturing fluid is a critical component of the hydraulic fracturing treatment. Its main functions are to open the fracture and to transport propping agent along the length of the fracture. Consequently, viscous properties of the fluid are often considered the most important (Economides *et al.* 2003). However, successful hydraulic fracture treatment requires that the fluids have some other special properties. In addition to exhibiting the proper viscosity in the fracture they should exhibit low friction pressure during pumping, providing good fluid loss control, break and clean-up rapidly after treatment and be as economical as practical (Economides *et al.* 2003). Since reservoirs vary in terms of temperature, permeability, rock composition and pore pressure therefore, a number of fluids have been developed to provide the properties described above.

2.4.1 Water Based Fluids

Because of their low cost, high cost and ease of handling water-base fluid is most widely used fracturing fluids. Potential problems with water-base fluids are formation damage caused by unbroken polymer and additives (Economides *et al.* 2003).

2.4.1.1 Polymers

Many water-soluble polymers can be added to water to make a viscosified solution capable of suspending proppants. One of the first polymers used to viscosify water for fracturing applications was guar gum. The guar polymer has very high affinity for water. When powder is added to the water guar particles swell and hydrate, which means the polymer molecules become associated with many water molecules and unfold and extend out into the solution (Economides *et al.* 1989).

Guar is a natural product. The process used to produce guar powder does not completely separate the guar from other plant materials which are not soluble in water.

Consequently, as much as 6 to 10 % of the guar powder will not dissolve and may cause damage to the formation face or proppant pack. To minimize this problem, guar can be derivatized with propylene oxide to produce hydroxypropylguar (HPG). The reaction changes some of the – OH sites to – O – CH₂ – CHOH – CH₃. The additional processing and washing removes much of the plant material from the polymer, so HPG typically contains only about 2 to 4 % insoluble residue. It is generally considered to be less damaging to the formation face and proppant pack than is guar although studies by (Almond *et al.* 1984) have indicated that both guar and HPG cause about the same degree of pack damage. However, HPG is better suited for high temperature wells (Economides *et al.* 1989).

Another derivative of guar which has been used in recent years is carboxymethylhydroxypropyl (CMHPG). This double derivatized guar contains the HPG functionality as well as carboxylic acid substitute. CMHPG is usually used in low – temperature wells (Almond *et al.* 1984).

Cellulose derivatives have also been used in fracturing fluids (Carico and Bagshaw, 1978). Hydroxyethylcellulose (HEC) or Hydroxypropylcellulose (HPC) is used when a very clean fluid is desired.

Another type of polymer is Xanthan gum. It is a biopolymer produced metabolically by the microorganism *Xanthomonas campestris* (Lipton and Burnett, 1976). Xanthan solutions behave as Power Law Fluids even at very low shear rates (Kirkby and Rockefeller, 1985), while HPG solutions become Newtonian. Xanthan is more expensive than guar or cellulose derivatives and therefore less frequently used.

2.4.1.2 Crosslinkers

The polymers mentioned above produce viscous solutions at ambient temperature, as the temperature increases these solutions thin significantly. To offset the thermal effects polymer concentration can be increased but this approach is expensive (Economides *et al.* 1989). Instead, crosslinking agents are used to dramatically increase the effective molecular weight of the polymer, thereby increasing the viscosity of the solution

(Economides *et al.* 1989). A number of metal ions have been used to crosslink water-soluble polymers (Conway *et al.*, 1980). Borate, Ti (IV) and Zr (IV) are by far the most popular. Al (III) is sometimes used to crosslink CMHPG and CMHEC because of the ion's affinity for crosslinking carboxyl groups at low pH. Antimony (V) has been crosslink guar and HPG for low-temperature applications.

2.4.2 Oil – Base Fluids

The original fracturing fluids were oil-base because these were perceived to be less damaging to the hydrocarbon-bearing formation than were water base fluids. Their inherent viscosity also made them more attractive than water (Howard and Fast, 1970).

Oil base fluids are expensive to use and are operationally difficult to handle. Therefore, oil based fluids are now only used in formations which are known to be extremely water sensitive or suffer permeability reduction when exposed to aqueous fluids (Economides *et al.* 1989).

In the 1960s industry used Aluminum salts of carboxylic acids (e.g. Aluminum Octoate) to raise the viscosity of hydrocarbon fracturing fluids (Burnham *et al.*). This improved the temperature stability and proppant carrying capability of the fluids. In the 1970s the Aluminum carboxylate salts replaced by Aluminum phosphate ester salts. Again the temperature range was extended and proppant transport was enhanced. Today, Aluminum phosphate chemistry remains the preferred method of gelling hydrocarbons for fracturing purposes.

2.4.3 Multiphase Fluids

There are situations in which the properties of standard water-base or oil-base fluids can be enhanced by incorporating a second phase into the fluids. Foams are created by adding gas to the water or oil-base fluids. Emulsions are created by mixing oil and water together.

2.4.3.1 Foams

Foam is a stable mixture of liquid and gas. To make the mixture stable surface-acting agent (surfactant) is used. The surfactant stabilizes the bubble surface and prevents coalescence.

Foam contains a pressurized gas (usually nitrogen or carbon dioxide) which expands when the well is flowed back and forces the liquid out of the fracture. Thus foams are excellent fluids to use in low-pressure reservoirs to achieve rapid cleanup. As foams contains 95 % gas (by volume) and liquid phase is minimal. In case of water-base fluid, foaming the fluid may significantly decrease the amount of liquid in contact with the formation. Therefore, foams perform well in the water sensitive formations (Ward, 1984; Ainley, 1983). Foams yield pseudoplastic fluids with good transport properties (King, 1982; Reidenbach et al, 1986). They provide good fluid loss control in low permeability formations where the gas bubbles are approximately the size of the rock pore openings.

2.4.3.2 Emulsions

An emulsion is a dispersion of two immiscible phases such as oil in water or water in oil, stabilized with a surfactant. Emulsions-base fracturing fluids are very viscous solutions with good transport properties. The higher the percentage of the internal phase the more resistance there is to droplet movement, resulting in higher viscosity.

The most commonly fluid is polyemulsion, composed of 67 % hydrocarbon internal phase, 33 % viscosified brine external phase and an emulsifying surfactant. Polymer acts as friction reducer. The polymer concentration used is generally 20 to 40 lb/1000 gal. The emulsion usually breaks through adsorption of the emulsifier onto the formation rock. Since so little polymer is used, this type of fluid is known for causing less formation damage and cleaning up rapidly (Roodhart *et al.* 1986).

Disadvantages of polyemulsions are high friction pressure and high fluid cost (unless the hydrocarbon is recovered). Polyemulsions also thin significantly as the temperature increases which limit their use in hot wells.

2.4.4 Additives

A fracturing fluid is generally not simply a liquid and viscosifying material such as water and HPG polymer or diesel oil and aluminum phosphate ester polymer. Various additives are used to adjust pH, control bacteria, improve high temperature stability, break the fluid once job is over, minimize formation damage and /or control fluid loss.

2.4.4.1 Buffers

Buffers are pH-adjusting chemicals which are added to aqueous fracturing fluids to maintain a desired pH. The buffers, weak acids or bases or both are used in sufficient quantity to maintain the pH at the desired level even if an extraneous acid or base is introduced through contaminated water or proppant.

2.4.4.2 Bactericides

Bactericides are added to polymer-containing aqueous fracturing fluids to prevent viscosity loss due to bacterial degradation of the polymer.

The polysacharrides (Sugar polymers) used to thicken water are a great food source for bacteria. Bacteria will not only ruin gel by reducing the molecular weight of the polymer but also they can turn sweet wells into sour ones. Once introduced into the reservoir, some bacteria survive and reduce sulfate ions to H₂S.

2.4.4.3 Breakers

Thermal breaking of the polymer gel generally occurs in the wells hotter than 225 °F. When treating lower temperature wells a breaker should be added to the fracture fluid. Ideally a gel breaker should be added to the fluid at surface which should not have any effect on the gel until pumping ceases (and fracture closes) and should rapidly react with

the gel. The viscosity of the gel and the molecular weight of the polymer should be significantly reduced to allow rapid cleanup of the sand pack (Almond *et al.* 1984).

2.4.4.4 Fluid – Loss Additives

Good fluid loss control is essential for an efficient fracturing treatment. Several types of materials are used to provide fluid-loss control but the effectiveness of the various types depends on the type of fluid-loss problem which is present such as:

- Loss to matrix
- Loss to minifractures
- Loss to macrofractures

During leakoff into the rock matrix fluid enters the pore spaces of the rock. Some polymers such as guar and HPG are filtered out on the surface of low permeability rocks. Fluids containing these polymers are called wall-building fluids because of the layer of polymer and particulates which builds up on the rock. This layer, called a filter cake is generally much less permeable than the formation. If the fluid contains particulates of the proper size, these particulates will tend to plug up the pore spaces and enhance the formation of the filter cake.

A material which has been shown to be an effective fluid-loss additive for helping to establish a cake is Silica Flour (Penny *et al.* 1985). This very fine sand is effective in reducing fluid loss to rock in the 2 to 200 mD range. Penny *et al.* 1985 reported that a 10 fold reduction in spurt loss for 5 to 100 mD rock when silica flour is used.

An effective and popular method for controlling fluid loss is to use emulsified fluids. These fluids are oil-in-water emulsions which contain a fairly small concentration of the diesel and exhibit good fluid-loss control.

2.5 PROPPING THE FRACTURE

The objective of propping is to maintain desired fracture conductivity economically. Fracture conductivity depends upon a number of interrelated factors such as, type, size

and uniformity of the proppant: degree of embedment, crushing, and/or deformation: and amount of proppant and the manner of the placement.

2.6 PROPPANTS

Sand was the first material used as a proppants (Economides *et al.* 1989). Some of the successful and more commonly used propping agents today include sand, resin-coated sand, intermediate-strength proppant (ISP) ceramics and high strength proppants (sintered bauxite, zirconium oxide, etc.). Because of its relatively low cost sand is the mostly used proppant especially in low closure stress (Economides *et al.* 1989). Since there are wide qualities of proppants therefore, American Petroleum Institute (API) established a test procedure to distinguish the quality and usefulness of each proppant. (API RP56, 1983)

2.6.1 Sand

Based on their physical properties sands can be divide into groups of excellent, good and substandard grades.

The excellent or premium sands come from Illinois, Minnesota and Wisconsin. They are mined from the Jordan sandstone and the St. Peter sandstone (Economides *et al.* 1989). They are commonly known as Northern sand, White sand, Ottawa sand, Jordan sand, St. Pete's sand and Wonewoc sand (Economides *et al.* 1989). These sands greatly exceed API standards and are used throughout the world.

The good or standard grade sands come from the Hickory sandstone near Brady, Texas. These sands have a darker color than the northern sands. Some of the common names are Texas brown sand, Brown sand, Brady sand and Hickory sand. These sands are less expensive and most widely used. The specific gravity of these sands is approximately 2.65 (Economides *et al.* 1989).

2.6.2 Resin-Coated Sand

Resin coatings may be applied to the sand to improve proppant strength. The resin is usually crosslinked (cured) during the manufacturing process to form a nonmelting inert film. Resin-coated sands have higher conductivity at high confining pressures than conventional sands (Economides *et al.* 1989). Resin helps to spread the stress over a larger area and reduces point loading. When the grain crushes, the resin encapsulates the crushed portions of the grains and prevents them from migrating and plugging the flow channel. The resin-coated proppants are pumped at the end of the treatment. The well is shut in for a time to allow the resin to bind contacting proppant particles together and cure into consolidated but permeable filter. Resin-coated sands usually have a specific gravity of about 2.55 (Economides *et al.* 1989).

2.6.3 Intermediate-Strength Proppants

Intermediate-strength proppants (ISP) are fused ceramic proppants that have a specific gravity between 2.7 and 3.3 (Economides *et al.* 1989). The variation in specific gravity is due to the raw material used to make the proppant. ISPs mainly used for closure stress ranges between 5,000 psi to 10,000 psi (Economides *et al.* 1989).

2.6.4 High-Strength Proppants

Sintered bauxite and zirconium oxide are high-strength propping agents with a specific gravity of about 3.4 or greater. Because of their higher cost they are limited only to the wells with very high closure stress (Economides *et al.* 1989).

2.7 PHYSICAL PROPERTIES OF PROPPANTS

The physical properties that affect the fracture conductivity include:

- Proppant strength
- Grain size
- Grain-size distribution
- Quality (amount of fines and impurities)

- Roundness and sphericity
- Proppant density

2.7.1 Proppant Strength

When a hydraulic fracture is created the in-situ stresses must be overcome to open and propagate the fracture. Once the hydraulic pressure is reduced, these same stresses tend to close the fracture. If the proppant is not strong enough to withstand the closure stress of the fracture it will be crushed and the permeability of the propped fracture will be reduced.

Figure 2.2a and 2.2b below shows conventional fracturing sand before and after an applied closure stress of 10,000 psi. Notice that proppant was of proper shape and well rounded before closure stress as shown in Figure 2.1a. while Figure 2.1b shows after applying closure stress. In this case proppant used are not of sufficient strength and could not withstand the 10,000 psi closure stress and crushed. This crushed proppants will reduce the fracture conductivity by reducing fracture width and also the crushed sand particles will plug the pore spaces between proppant grains.

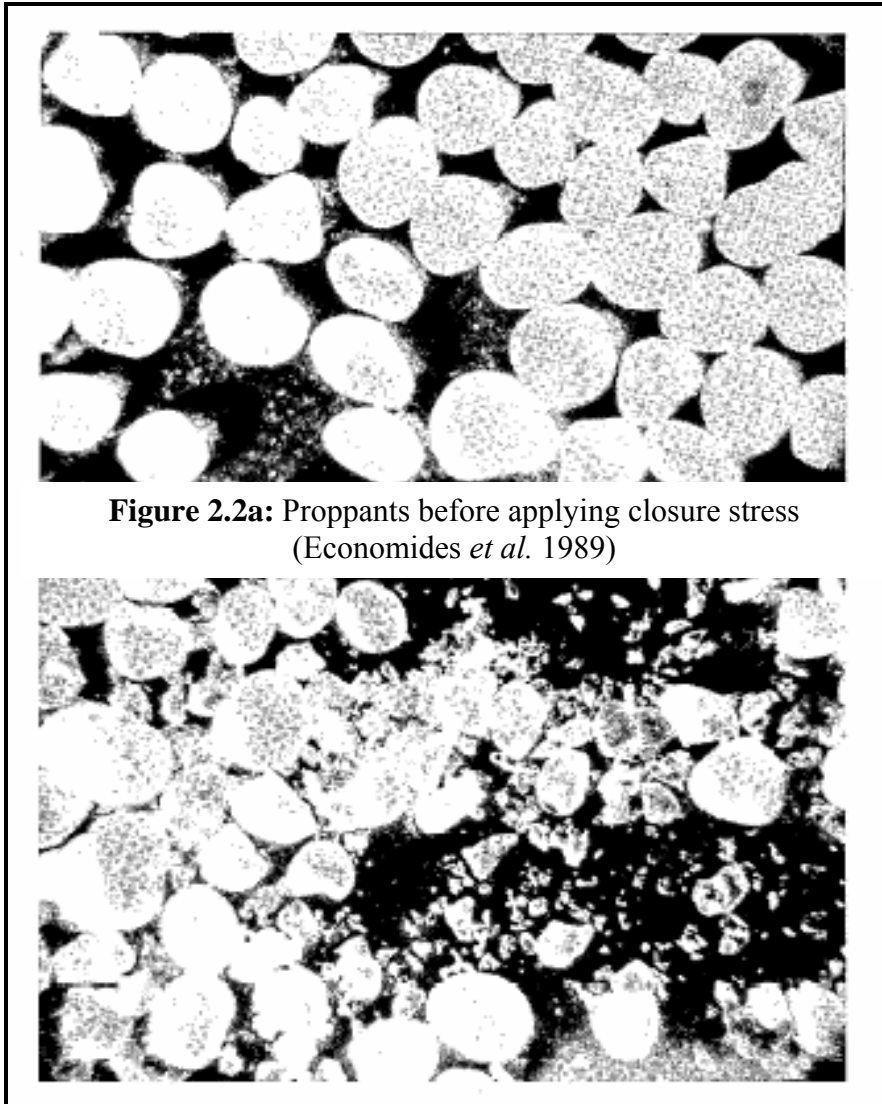


Figure 2.2a: Proppants before applying closure stress (Economides *et al.* 1989)

Figure 2.2b: Effect of very high closure stress on sand (Economides *et al.* 1989)

2.7.2 Grain Size and Grain Size Distribution

Proppants with larger proppant grain sizes provide a more permeable pack. However, their use must be evaluated in relation to the formation that is propped and the increased difficulties encountered in proppant transport and placement. Dirty formations or those subject to significant fines migration are poor candidates for large proppants. The fines tend to invade the proppant pack causing partial plugging and rapid reduction in permeability. In these cases smaller fines are more suitable although they offer less

conductivity. Larger grain sizes can be more difficult to use in deeper wells because of greater susceptibility to crushing as grain size increases, strength decreases and placement problems (Economides *et al.* 1989).

Figure 2.3 illustrates the effect of grain size on the permeability of high-quality sand at increasing closure stresses. Figure shows different size of sand particles i.e. 12/40, 20/40, 30/40 and 40/40. As can be seen that permeability reduces with increasing closure stress, however, closure stress has less effect on the greater grains.

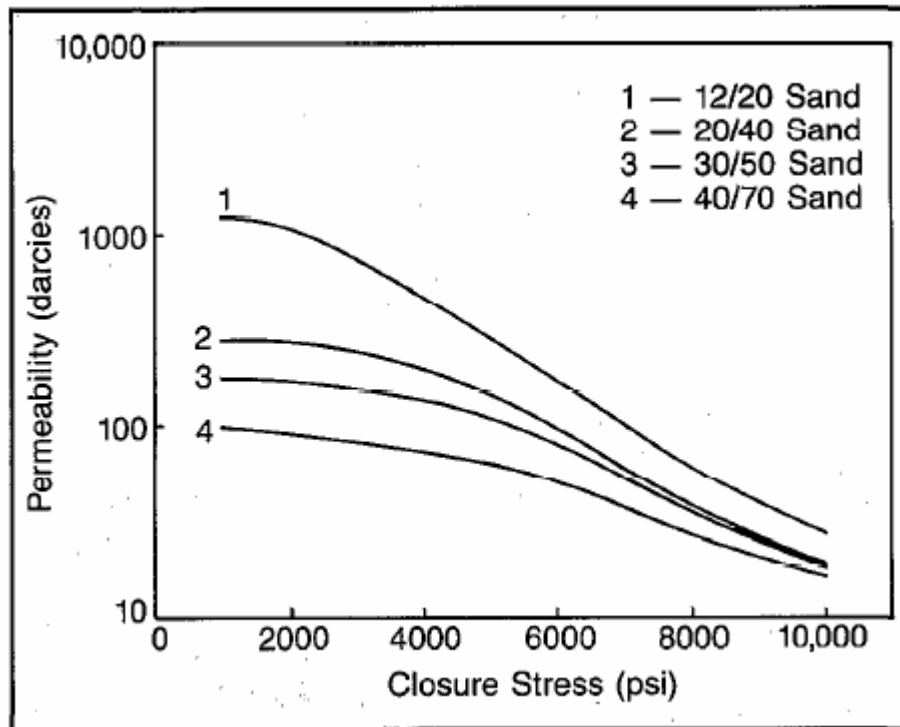


Figure 2.3: Effect of grain size on strength. Permeability vs Closure stress of northern white sand (Economides *et al.* 1989).

2.7.3 Quality

Grain-size distribution and proppant quality are closely related. A high percentage of smaller grains or impurities can have the same effect on the proppant-pack permeability as invading formation fines.

2.7.4 Roundness and Sphericity

Particle sphericity is a measure of how close the proppant particle grain approaches the shape of a sphere. The roundness and sphericity of a grain can have a dramatic effect on fracture conductivity. Stresses on the proppant grains are more evenly distributed when the grains are round and about the same size.

2.7.5 Proppant Density

Proppant density has an influence on the proppant transport and placement. High-density proppants are more difficult to suspend in the fracturing fluid and to transport in the fracture. Placement of the proppant can be achieved in two ways:

1. Using high –viscosity fluids which carry the proppant for the entire length of the fracture with minimal settling.
2. Using low – viscosity fluids and a higher flow velocity.

2.8 ROCK MECHANICS

Knowledge of rock mechanics is very important in hydraulic fracturing treatment design. Rock mechanics can affect the fracture by reducing fracture conductivity. As mentioned earlier that proppants will be crushed due to higher closure stress therefore, it is necessary that proppant selected must have sufficient strength to withstand stresses. Some of the important properties of rock mechanics are briefly explained in the following section.

2.8.1 Insitu Stress

There are three principle earth stresses oriented at right angles to one another as shown in **Figure 2.4**.

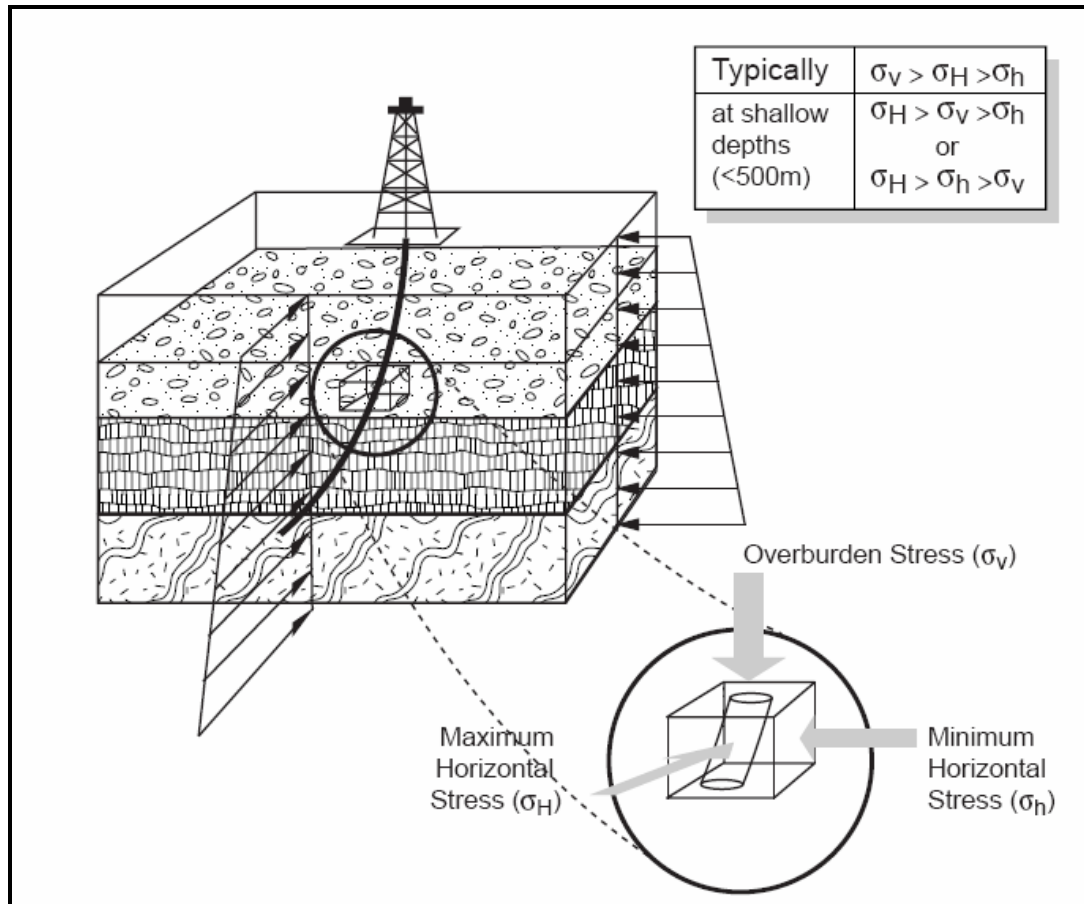


Figure 2.4: Insitu stresses in the subsurface (Davies. 2007).

Three principle stresses are:

$\sigma_v \equiv$ Vertical Stress (Overburden Stress)

$\sigma_H \equiv$ Maximum Horizontal Stress

$\sigma_h \equiv$ Minimum Horizontal Stress

Normally below 500 m in a tectonically relaxed environment the vertical stress is the greatest. An average value of 1.0 to 1.1 psi/ft is measured for wells at reasonable depth (Davies. 2007).

Above 500 m,

$$\bar{\sigma}_v > \bar{\sigma}_H > \bar{\sigma}_h$$

At shallow depth (< 500 m),

$$\bar{\sigma}_H > \bar{\sigma}_v > \bar{\sigma}_h \text{ or}$$

$$\bar{\sigma}_H > \bar{\sigma}_h > \bar{\sigma}_v$$

2.8.2 Young's Modulus

The amount of strain caused by a given stress is a function of the stiffness of a material. Stiffness can be represented by the slope of the axial stress-strain plot and is termed as Young's Modulus (E).

$$E = \frac{\text{Stress}}{\text{Strain}} \quad (2.1)$$

$$E = \frac{\sigma}{\varepsilon} = \text{lb/in}^2 \quad (2.2)$$

For mild steel, value of "E" is 30×10^6 Psi and for rock it ranges from 0.5 to 12×10^6 Psi.

2.8.3 Poison's Ratio

Compressive stress applied to a block of material along a particular axis causes it to shorten along that axis but also to expand in all directions perpendicular to that axis as shown in **Figure 2.5**. The ratio of strain perpendicular to the applied stress to strain along the axis applied stress is termed as Poison's ratio.

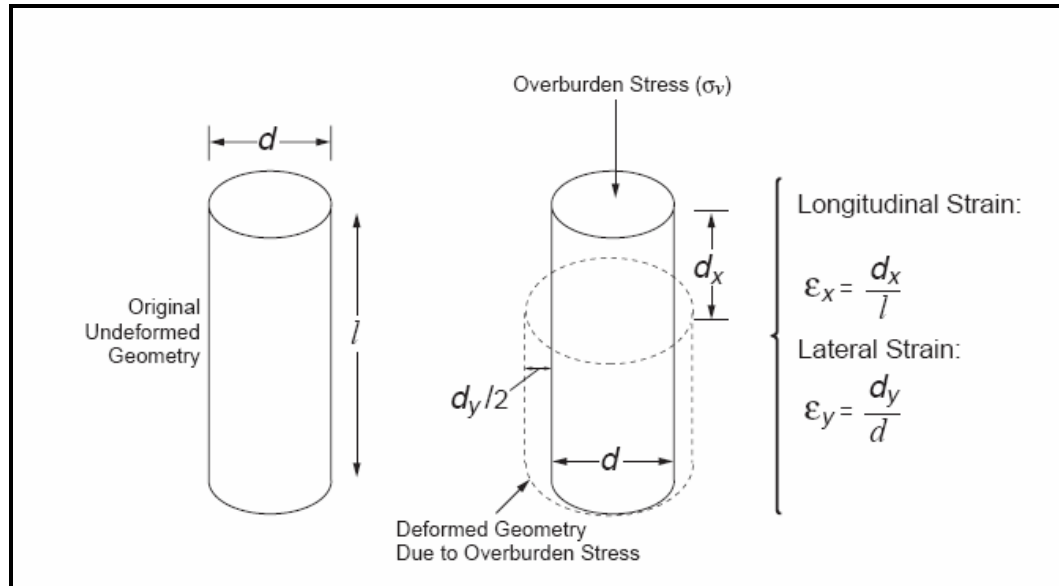


Figure 2.5: Measurement of Poisson's ratio (Davies. 2007).

$$v = \text{Lateral Strain}/\text{Axial Strain} \quad (2.3)$$

A material that under stress deforms laterally as much as it does axially would have a Poisson's ratio of 0.5 while a material that does not deform laterally under axial load would have a Poisson's ratio of 0.0.

2.8.4 Effective Stresses

The pore fluids present within the rock matrix will support a proportion of the total applied stress. This means that effective stress (σ') carried by the rock matrix grains is smaller than the total stress (Davies *et al.* 2007).

$$\sigma' = \sigma - P \quad (2.4)$$

Where σ is the total stress, P is the pore pressure and σ' the effective stress which will govern the failure of the material.

It was later recognized that the intergrain cementation does not allow the pore pressure to completely counteract the applied load (Davies *et al.* 2007). A correction factor, the elastic constant α , was introduced:

$$\sigma' = \sigma\alpha - P \quad (2.5)$$

Where α can vary between 0 and 1 but has a typical value of 0.7 for petroleum reservoirs.

One important conclusion from these equations is that the values of the stresses which control fracture propagation can change as the reservoir pressure depletes during the life of a petroleum reservoir. Hence the stress profile measured early in a field's lifetime may become invalid as the field matures (Davies. 2007).

2.8.5 Fracture Size

Greater volumes of fracturing fluid will create larger fractures with greater treatment costs but also potentially more productive. However, often uncontrolled growth of fractures is not desirable from a production point of view, e.g. when the target oil zone is overlain by a gas with water underneath as shown in **Figure 2.6** (Davies. 2007).

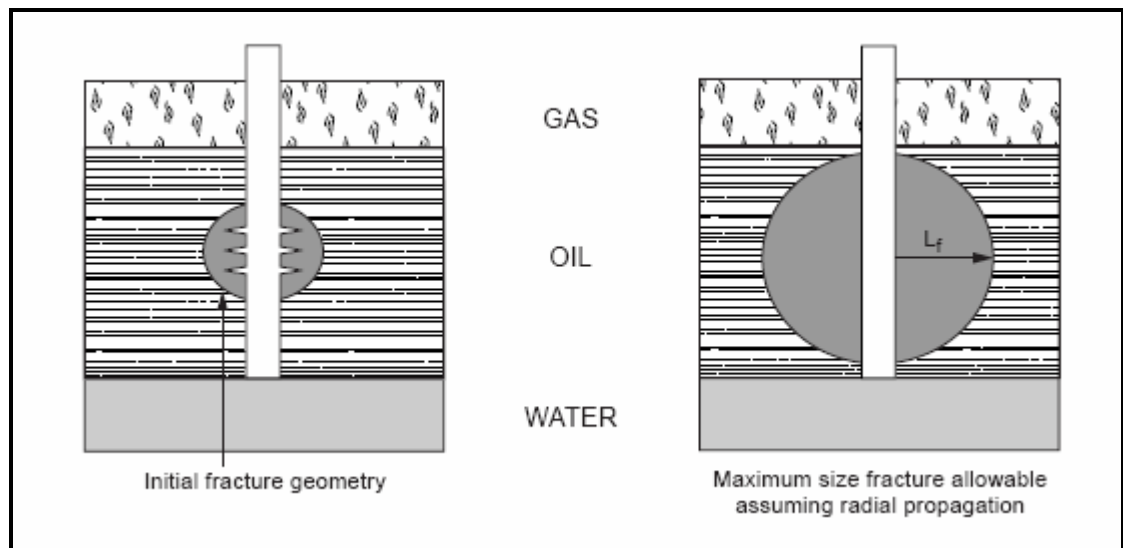


Figure 2.6: Fracture size limited by geometry and fluid contacts (Davies. 2007).

2.8.6 Fracture Containment

The hydraulic fracture should thus be designed so that it does not contact unwanted fluids within a single formation layer. It must also be considered whether the hydraulic

fracture is contained within the pay zone i.e. whether upward and/or downward fracture growth is retarded by changes in the formation property contrast between the two layers (Davies.2007).

2.8.7 Fracture Growth into Boundaries

Whether a pay zone boundary is capable of containing a fracture will depend on the magnitude of the fracture containment mechanism e.g. minimum insitu stress contrast and the thickness of the boundary (Davies. 2007). **Figure 2.7a, 2.7b and 2.7c** schematically illustrate fracture containment for 3 different values of stress contrast. Initially the fracture propagates radially in the pay zone until the boundary layer is reached; after which fracture becomes more elongated in zone with greater contrast while in zones with lower stress contrast fracture grows into the adjacent layer.

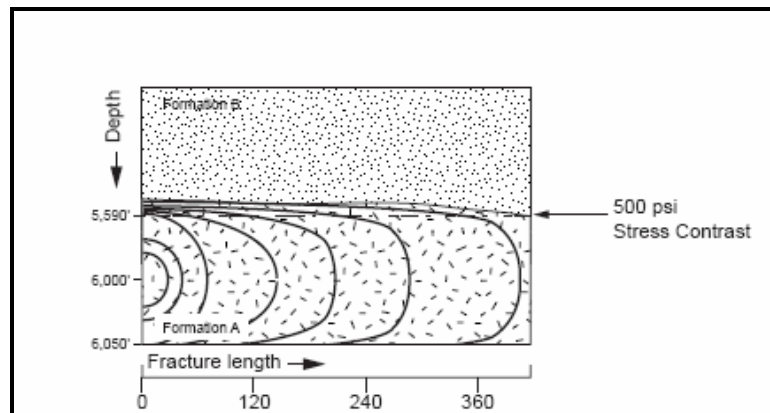


Figure 2.7a: Upward fracture growth stopped at formation boundary (Davies. 2007).

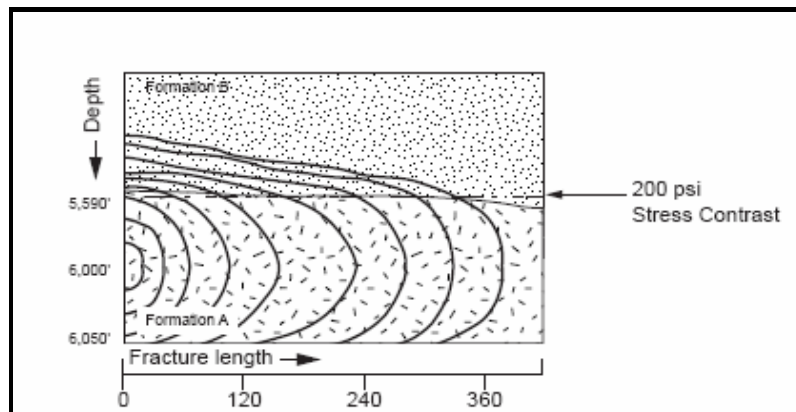


Figure 2.7b: Limited upward fracture growth at formation boundary (Davies. 2007).

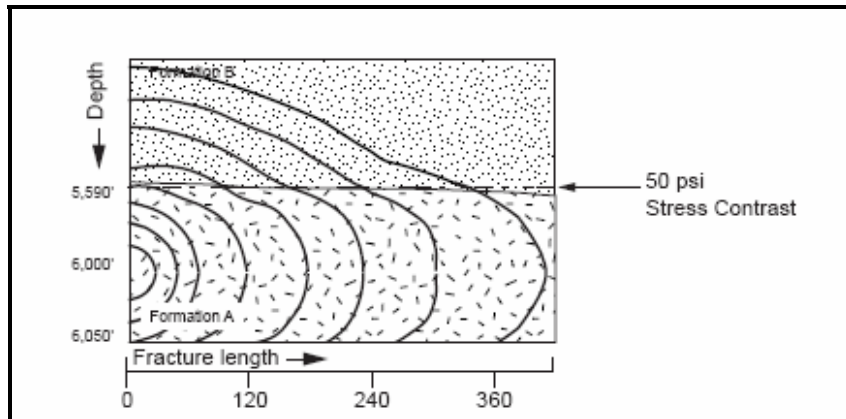


Figure 2.7c: Almost unimpeded upward fracture growth (Davies. 2007).

2.9 CHALLENGES IN HYDRAULIC FRACTURING

There are many challenges with hydraulic fracturing. The two paramount challenges identified by (Smith *et al.* 2001, Talbot *et al.* 2000, Warpinski *et al.* 1992, Arp *et al.* 1986, Simonson *et al.* 1978 and Daneshy 1978) are:

- Fracture Containment
- Propped Fracture Conductivity Reduction

2.9.1 Fracture Containment

Failure to contain fracture height growth during hydraulic fracturing treatments often renders uneconomical results which drastically alter pay-out, overall hydrocarbon recovery and profitability. Problematic production of water from outside the zone of interest can rarely be reversed. Here the operator incurs the additional expense of water disposal and decreased hydrocarbon inflow at wellbore. Likewise, vertical growth into gas cap in most cases is undesirable from the standpoint of decreased primary recovery (Arp *et al.* 1986).

For optimized well performance by a fracture stimulation program, adequate fracture half-length and fracture conductivity are the two most important parameters (Talbot *et al.* 2000).

Since,

$$F_{cd} = \frac{k_f \times W}{k \times L_f} \quad (1.3)$$

Where,

$F_{cd} \equiv$ Fracture conductivity

$k_f \equiv$ Fracture permeability

$W \equiv$ Conductive fracture width

$k \equiv$ Formation permeability

$L_f \equiv$ Conductive fracture single wing length

Fracture half-length is more of concern in lower permeability zones, and since fracture height varies inversely with fracture length the lower the fracture height, the greater the fracture length (for the same net pressure). An operating necessity is therefore to control the height of a fracture in the formation zone of interest (Talbot *et al.* 2000).

2.9.1.1 Factor affecting Vertical Growth

The dominant factor in controlling vertical height growth is the stress contrast between the pay zone and the barriers (Ben *et al.* 1990). Warpinski *et al.* 1992 found that a stress difference of 200 to 500 Psi between the pay zone and adjacent intervals were necessary to contain the fracture to their zone of interest. A value of stress difference also confirmed by other studies (Mukherjee *et al.* 1992, Morita *et al.* 1988 and Cleary *et al.* 1980).

On their part (Teyfel *et al.* 1981) concluded that an increase of 700 psi in horizontal stress was required for complete containment in a number of limestone and sandstones.

Many studies have been conducted on the effects of formation's Young's modulus, in situ stress, fracture toughness and layer interfaces on hydraulic fracture height containment in layered formations (Smith *et al.* 2001, Warpinski *et al.* 1998, 1982, Wang and Clifton 1990, van Eekelen 1982, Simonson *et al.* 1978 and Daneshy 1978). Because of these studies it is now well known that in situ stress contrast is the dominant parameter controlling fracture height growth and Young's modulus contrast is less important. When studying different height – containment mechanisms, modulus contrast is often considered separately from stress contrast to isolate the effect of each parameter. In reality, formation layers of different moduli are likely to have different in situ stresses (Teufel and Clark. 1984) and the contributions of both must be considered together.

The topic of combining the effects of in situ stress and modulus contrast was further expanded by (Hongren Gu *et al.*, 2008). A parametric study was done using P3D hydraulic fracture simulator to demonstrate the combined effects of modulus contrast and stress contrast on fracture geometry (Hongren Gu *et al.*, 2008). Symmetric three layers formation was considered as shown in **Figure 2.8** (Hongren Gu *et al.*, 2008).

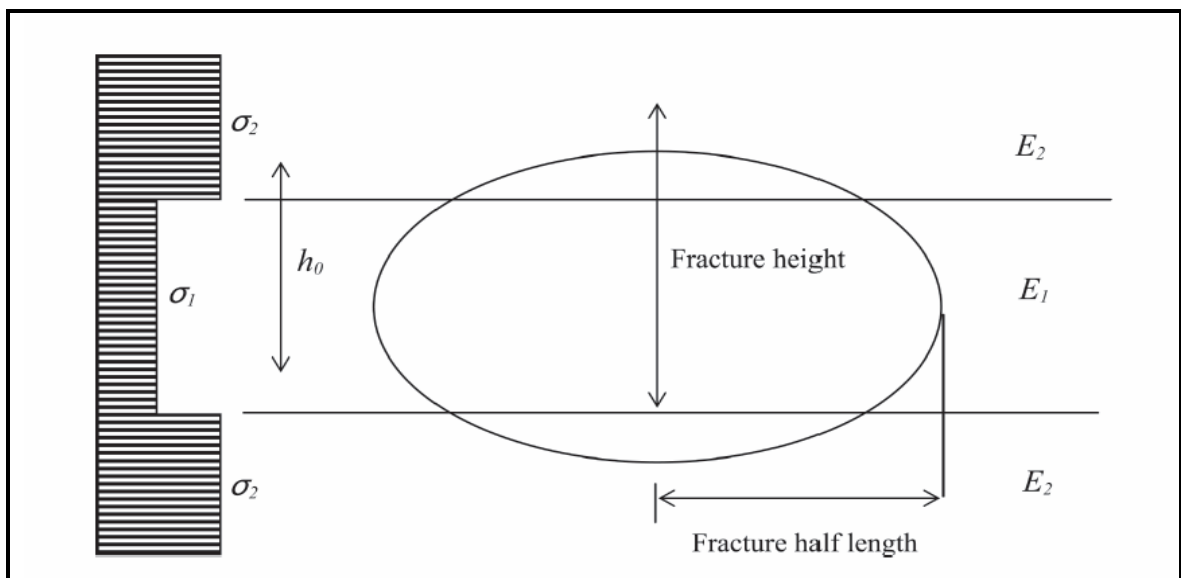


Figure 2.8: Schematic of hydraulic fracture in three layer formation (Hongren Gu *et al.*, 2008).

The middle layer has a Young's modulus " E_1 " and minimum horizontal stress σ_1 . The upper and lower bounding layers have a different Young's modulus " E_2 " and in situ stress σ_2 . It is assumed that there is no slippage between the bounding layers (perfect bonding). The hydraulic fracture is initiated in the middle layer and the initial height h_0 is the middle – layer height. The fluid injection rate is constant, which is common practice in hydraulic fracturing treatments and the fluid pressure is calculated by the simulator (Hongren Gu *et al.* 2008).

Result of these studies and other earlier studies show that modulus contrast hinders fracture growth (Hongren Gu *et al.*, 2008): a higher – modulus layer hinders fracture growth before the fracture tip reaches the high – modulus layer; a low – modulus layer hinders fracture growth when the fracture tip is inside the low – modulus layer. A fracture tip is likely to terminate in a low – modulus layer (Hongren Gu *et al.*, 2008). These hindering could be one of the mechanisms that contribute to unexpected height containment when a formation has layers of contrasting moduli (Hongren Gu *et al.* 2008).

2.9.2 Propped Fracture Conductivity Reduction

Another key challenge is to achieve good fracture conductivity because greater the fracture conductivity more productive the fracture will be. We have already seen that fracture conductivity is:

$$F_{cd} = \frac{k_f \times W}{k \times L_f} \quad (1.3)$$

Where,

k_f is Fracture permeability and is one of the main factor responsible for the reduction of the fracture conductivity. Fracture permeability reduction noticed in many previously hydraulically fractured wells is attributed to:

- Type and strength of proppant

➤ Fracturing fluid

2.9.2.1 Type and Strength of Proppant

The proppant placed within the fracture is stressed as the fracturing fluid leaks away and the fracture closes. **Figure 2.9** illustrates how the fracture closing stress affects the proppants depending on the properties of the proppant and the strength of the formation.

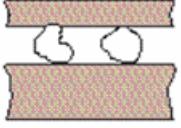

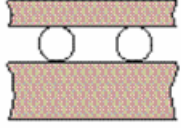

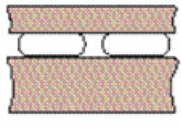
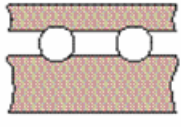
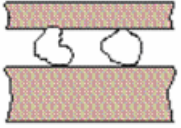
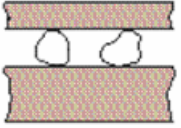
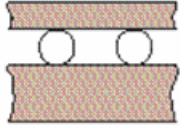

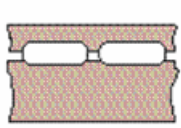
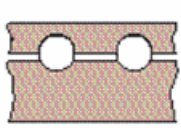
Hard Rock	No Closure Pressure	Sand Grains 	Soft Proppants 	Hard Proppants 
	Closure Pressure Applied	Crushing 	Deformation 	Little Embedment 
Soft Rock	No Closure Pressure	Sand Grains 	Soft Proppants 	Hard Proppants 
	Closure Pressure Applied	Crushing and Embedment 	Deformation 	Much Embedment 

Figure 2.9: Behavior of proppants under stress (Davies. 2007)

Figure 2.8 shows three different types of proppants i.e. sand grains, soft proppants and hard proppants and effect of rock stresses before and after closing. Closing stress will result in:

- i. Crushing of the proppant grains leading to reduced proppant permeability, and hence reduced fracture conductivity.
- ii. Deformation of (soft) proppants which leads to reduced proppant width, and hence reduced fracture conductivity.
- iii. Embedment of the proppant in the fracture wall, leading to further reduction in fracture conductivity.

So, it shows fracture conductivity as a result of combination of the proppant type (quality) and the formation properties. However, better rounded a proppant is the higher its permeability will be for the same proppant size. Furthermore, its strength will also be greater since the fracture closing stress will spread more evenly over the proppant grain's surface.

2.9.2.2 Fracturing Fluid

This is another factor which reduces the fracture conductivity. Most modern fracturing fluid consists of a low concentration of a polymer dissolved in the brine. The dilute polymer viscosity is increased by joining the polymer molecules together with a crosslinking agent. During the fracture treatment this dilute polymer solution is pumped into the fracture at a pressure much greater than the reservoir pressure – resulting in a high percentage of the brine “leaking off” into the formation. The large polymer molecules are too large to be able to flow through the pore throat and hence form an external filter cake on the fracture surface. This is particularly true in low permeability reservoirs (Davies. 2007).

Guar based polymers are used extensively in hydraulic fracturing applications to provide the necessary transport properties to deploy the proppant into the fracture. The polymers are typically too large to penetrate the formation matrix and consequently are concentrated within the fracture due to dynamic fluid loss during the pumping treatment and fracture volume reduction upon closure. These concentration phenomena result in the formation of filter cakes which are elevated concentrations of polymer deposited on the fracture face and within the proppant pack. The concentration of these filter cakes can range from 5 to 25 times the surface polymer concentration depending on the

reservoir properties, treatment design, proppant concentration and location in the fracture. Filter cakes with polymer concentration of this magnitude are of high viscosity, low permeability and practically insoluble (Brannon *et al.* 1995).

Normally chemical breaker is added to the fracturing fluid to degrade the fracturing fluid viscosity once the job completed. However, it is not capable of destroying the filter cake, which remains in the fracture. This further degrades fracture conductivity.

The efficiency of the removal of the remnants of the fracturing fluid from the proppant pack itself is measured by the retained fracture conductivity.

$$\text{Retained fracture conductivity} = \frac{(\text{conductivity after exposure to fracturing fluid} \times 100\%)}{\text{Conductivity prior exposure to fracturing fluid}} \quad (2.6)$$

Thus it can be imagined that the type and concentration of polymer used to prepare the fracturing fluid effects the fracture conductivity. Retained fracture conductivities for a number of different fracturing fluids are illustrated in **Figure 2.10**.

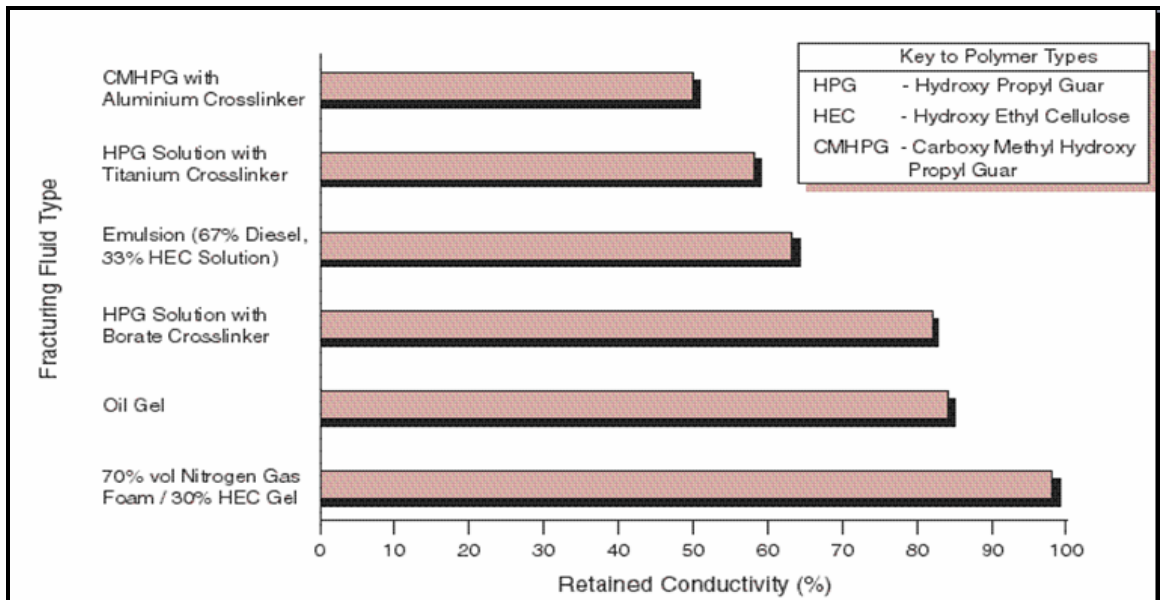


Figure 2.10: Typical values for fluid type and retained fracture conductivity (Davies, 2007)

As stated earlier that chemical breaker is added to degrade the fluid viscosity is capable of partially destroying the filter cake. An increased breaker concentration results greatly to increase retained fracture conductivity. However, addition of large concentration of breaker to the fracturing fluid is not viable approach since this will result in the fluid viscosity being degraded during, rather than after, the hydraulic fracturing treatment. This early decrease in fracturing viscosity will prevent the (denser) proppant being transported to the tip of the fracture. Instead, the proppant will sink to the bottom of the fracture under the influence of gravity and a premature screen out can result.

A study by Cook in 1973 showed that earlier permeability values are optimistic. The elevated temperature and brine flow at elevated closure stresses were found to be detrimental while solid fluid – loss additives in normally used concentrations were found to have little effect on proppant – pack permeability.

(Penny *et al.* 1987, McDaniel *et al.* 1986 and Parker *et al.* 1987) worked and published much in the area of proppant conductivity. These results have shown that a dramatic reduction in permeability occurs with time at closure stress.

Important gelling properties can further be identified as residue volume, molecular weight/size and residue volume after action of a given fracture fluid breaker or thermal degradation. The formation of an immobile residue arising from the concentration of the gelling agent due to fluid – loss and fracture closure and/or as the result of breaking mechanism has been determined to be a major source of permeability reduction (Hawkins *et al.* 1988). **Table 2.1** summarizes the factors which influence the effective proppant permeability.

Table 2.1: A summary of factors affecting proppant conductivity (Davies. 2007).

PROPPANT	FRACTURING FLUID	FRACTURE GEOMETRY & PRODUCED FLUID
Size (Average grain size and grain distribution)	Polymer type and concentration	Fracture width (especially at wellbore)
Grain roundness and Sphericity	Fluid loss additives	Reduced permeability due to produced fluid Non – Darcy or Turbulent flow effects at high flow rates and multiphase flow
Proppant crush resistance & Fracture closure stress	Crosslinker type	
Time	Breaker type and concentration	
Temperature	Temperature	

2.10 Summary of Literature Review

Hydraulic fracturing technique was introduced in 1949 and since then has been improved time to time (Economides *et al.* 1989). Major elements in treatment design and execution include selection of fracturing fluid, proppant type and strength selection and knowledge of rock mechanics. However, if any of these factors have been overlooked, instead of increase it can cause further decline in production. Two major challenges identified by (Smith *et al.* 2001, Talbot *et al.* 2000, Warpinski *et al.* 1992, Arp *et al.* 1986, Simonson *et al.* 1978 and Daneshy 1978) are 1) Fracture containment and 2) Fracture conductivity. Fracture containment is a property of the formation and depends on the stress contrast between the adjacent layers while fracture conductivity depends on the type of proppant selected and used in the treatment.

CHAPTER 3

METHODOLOGY

Methodology of the project is described in **Figure 3.1**. This study begins with literature review (ch-2). Literature review helps to identify key elements of hydraulic fracture treatment. It includes knowledge of pre-data requirement, fracturing fluid, proppants properties and rock mechanics. Like every job there are challenges associated with the hydraulic fracturing process. Goal of this study is to identify challenges, most frequently encountered in fracturing. For proper identification of the key challenges and sources responsible for that a sequential methodology used:

1. The first step in this research is to identify the key challenges in the hydraulic fracturing treatment through literature review. This explains the problems associated with the failure of the hydraulic fracturing treatment and possible factors responsible for these challenges.
2. In step two case studies have been selected from different parts of the world related to the hydraulic fracturing treatment of low permeability reservoirs. These case histories discuss key challenges and different techniques applied in the industry to overcome these problems.
3. Third step is to discuss the results of these case studies and compare the results of the well fracture stimulated by applying different techniques and fracture without using proposed techniques.

Finally conclusions and recommendations are made based on the result of these case studies and previously conducted successful jobs.

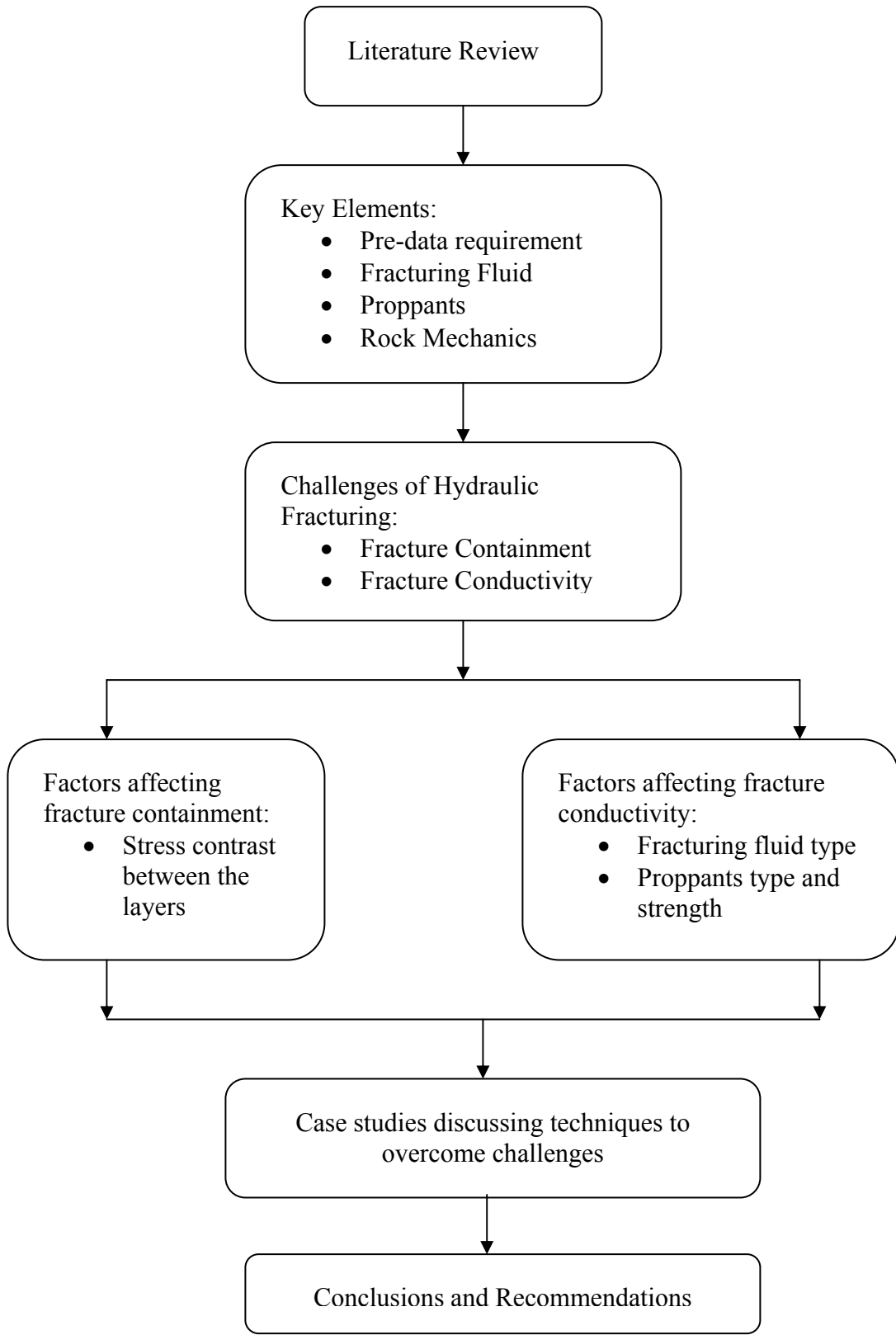


Figure 3.1: Methodology of project

CHAPTER 4

RESULTS AND DISCUSSION

4.1 INTRODUCTION

This chapter discusses the techniques being used in the industry to control the fracture height growth (above and below) and to retain fracture conductivity. As illustrated before that these two are the major challenges being faced by the industry to achieve a successful hydraulic fracturing treatment. Both of these are operational problems and being faced onsite. However, different techniques have been suggested by the authors to control fracture vertical growth and improve fracture conductivity. Some of the successfully applied techniques are briefly discussed in the following section.

4.2 TECHNIQUES TO CONTROL VERTICAL GROWTH

Treatments were proposed time to time to achieve the desired results from a hydraulic fracturing treatment applied to the low permeability wells. However, one of the most successful techniques which have been supported by various authors is to apply artificial barriers to the adjacent layers. Three techniques are discussed in this chapter. These are:

- Bracketfrac
- Invertfrac
- Divertfrac

A brief explanation of the three techniques suggested by different authors is illustrated below. These techniques have already been applied successfully to contain the fracture. Results of wells fracture treated by applying artificial barriers are presented from different fields around the world as a reference.

4.2.1 Bracketfrac

Arp *et al.* 1986 reported improved production by designing upper and lower fracture height control, using lighter proppant (upper control) and a mixture of silica flour, 70/140 mesh, 20/40 sand and 10/20 sand (lower control) at 3300 lb each at 5 bbl/min. after a forty-five minutes shut-in, the main treatment of 59400 lb of 20/40 proppant was pumped at 7 bbl/min. Arp *et al.* criticized the use of low-rate low-concentration fractures claiming such programs yielded less fracture conductivity and thus less well productivity.

4.2.2 Invertafrac

Nguyen *et al.* 1983 proposed a method to create an artificial barrier to control undesired upward fracture propagation. The artificial barrier proposed was built using a buoyant diverter which was pumped as slurry before the sand stages of a fracture treatment. During the treatment the buoyant diverter particles accumulate in the uppermost portion of the newly created fracture, forming a compact low – permeability flow block.

4.2.3 Divertafrac

Nolte 1982 proposed a technique to contain fracture height down growth in the Cotton Valley sand. In which a mixture of silica flour, 100 mesh, 20/40 mesh and 12/20 mesh sand was pumped in a high – viscosity fluid immediately after a pre – pad and before the proppant slurry was pumped into the fracture. The sand mixture was designed to bridge in the vertical tips of the fracture to form a “flow block” and discourage the fracture from growing further vertically.

4.2.4 Using Viscous Fracturing Fluid

Mukherjee *et al.* 1993 suggested that in formations suffering from fracture growth, use of a viscous fracture fluid pre-treatment to create a channel keeps the fracture tip open. This preparation is followed by 5 to 10 cp slurry carrying a mix of heavier and lighter proppants to plug the top and bottom fracture tips.

4.3 CASE STUDY – 1

The case is from one of the field in Netherlands. Reservoir is low permeability reservoir with the permeability in the range of 1 to 2 md. Major challenge in the design and the execution of the job was to contain the fracture in the pay zone because of very weak adjacent formations. To control the fracture propagation in the adjacent formations artificial barriers were used. Once artificial barriers are applied to the wells suffering from the fracture growth next step is to investigate the success of the job. Rogelio *et al.* 1997 conducted a study by tagging tracer to the proppant to allow direct measurement of the height fracture propagation and to link the containment or not to production responses. Results of this study are presented here. **Table 4.1** gives information data for wells.

Table 4.1: Information data for wells, fractured with height growth control (Rogelio *et al.* 1997)

Properties	Well Number				
	I	II	III	IV	V
Bottom-Hole Static Pressure (psi)	1350	1500	1500	1400	1500
Porosity (%)	12	12	20	12	12
Permeability (md)	2	1.5	1.5	2	2
Formation Thickness (ft)	78	98	82	92	90
Kh (md-ft)	156	147	123	184	180
Casing Diameter (in)	6 5/8	6 5/8	6 5/8	6 5/8	6 5/8
Tubing Diameter (in)	2 7/8	2 7/8	2 7/8	2 7/8	2 7/8
Depth to the top of formation (ft)	5512	4050	4626	5330	4642
Fracture Gradient (psi/ft)	0.66	0.83	0.7	0.83	0.72
Formation Type	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone
Young's Modulus (psi)	3.05E+06	2.70E+06	2.70E+06	2.70E+06	2.70E+06

Table 4.1 shows that reservoir is sandstone with permeability ranging from 1.5 to 2 mD. Reservoir is low pressure and a possible candidate for the hydraulic fracturing. Five wells were fractured under different scenarios of fracture height growth control, two with control of propagation upward, one downward and two with both. In all cases proppant was tagged with zero-wash Iridium (Ir-192) except for well IV where the pad was tagged with Antimony (Sb-124), in addition to the proppant stages 1-7 lbs/gal with Ir-192 and the proppant stages 7-8 lbs/gal with Scandium (Sc-46).

4.3.1 Well – I and V

Well I and V were fractured controlling both upward and downward height growth (bracketfrac) by pumping different diverting materials. Initially 2000 lbs of 100 mesh silica plus 1000 lbs of 20/40 sand to act as the diverting material for downward growth. There is a shut-in period of 60 minutes. After these 800 lbs of the light weight diverting material is pumped which is designed to float and inhibit the growth of the fracture upward. Finally a shut-in of 120 minutes prior to the pumping of main treatment. Note that there are shut-in period, 60 minutes after the divertafrac and 120 minutes after the invertafrac. These shut-ins are designed to allow the diverting material to either settle to the bottom or float to the top and become the so called artificial barriers for the actual propped fracture which is pumped following these fracture pre-conditioning. Fluid used during the treatment is hydroxypropylguar (HPG) which is achieved when guar is derivatized with propylene oxide. This fluid is pumped at varying rate such as 15, 4 and 18 barrel per minute (bpm). Pumping Schedules followed in each case are presented in **Tables 4.2** and **4.3**

Table 4.2: Well I bracketfrac and fracture pumping schedule (Rogelio *et al.* 1997)

Pumping Schedule Well I			
Mix of 2000 lbs of 100 mesh sand and 1000 lbs of 20/40 mesh sand			
Fluid Volume (Gallons)	Fluid Type	Pumping Rate (bpm)	Stages
3000	HPG-20 Lb GEL	15	Prepad
2000			1.5 PPA DIVERTAFRAC
2500		4	Flush
Shut-in for 60 minutes			
800 lbs of diverting agent			
3000	HPG-20 Lb GEL	18	Prepad
2650			0.3 PPA INVERTFRAC
2500		4	Flush
Shut-in for 120 minutes			
10000	HPG-20 Lb GEL	15	Prepad
22000	HPG-40 LB X-LINK GEL		Pad
1500			1 PPA LWP Plus 12/18
4000			2 PPA LWP Plus 12/18
6000			3 PPA LWP Plus 12/18
7000			4 PPA LWP Plus 12/18
7500			5 PPA LWP Plus 12/18
8000			6 PPA LWP Plus 12/18
8500			7 PPA LWP Plus 12/18
5000			8 PPA LWP Plus 12/18
1500	HPG-20 Lb GEL		Flush

Table 4.3: Well V bracketfrac and fracture pumping schedule (Rogelio *et al.* 1997)

Pumping Schedule Well V			
Mix of 2000 lbs of 100 mesh sand and 1000 lbs of 20/40 mesh sand			
Fluid Volume (Gallons)	Fluid Type	Pumping Rate (bpm)	Stages
3000	HPG-20 LB GEL	18	Prepad
2000			1.5 PPA DIVERTAFRAC
2500			Flush
Shut-in for 60 minutes			
800 lbs of diverting agent			
3500	HPG-20 LB GEL	18	Prepad
2650		0.3 PPA INVERTFRAC	
2500		4	Flush
Shut-in for 120 minutes			
10000	HPG-20 LB GEL	18	Prepad
26000	HPG-40 LB X-LINK GEL		Pad
2500			1 PPA LWP Plus 12/20
3000			2 PPA LWP Plus 12/20
3500			3 PPA LWP Plus 12/20
4000			4 PPA LWP Plus 12/20
5500			5 PPA LWP Plus 12/20
6000			6 PPA LWP Plus 12/20
7500			7 PPA LWP Plus 12/20
8500			8 PPA LWP Plus 12/20
1300			9 PPA AcFrac PR 12/18
1100	HPG-20 LB GEL	15	Flush

Pressure analysis has been used to investigate the proper placement of the diverting materials. Net pressure from the dead string can be used to identify the fracture growth.

Positive slope in the net pressure from the dead string is a characteristic of contained fracture growth.

Figure 4.1 and **4.2** below shows net pressure profile for well I and V respectively. Notice in **Figure 4.1 and 4.2**, after 45 minutes and 40 minutes respectively after the start of the pumping that the slope is changed and continuous positive slope can be seen. This indicates the proper placement of the barriers.

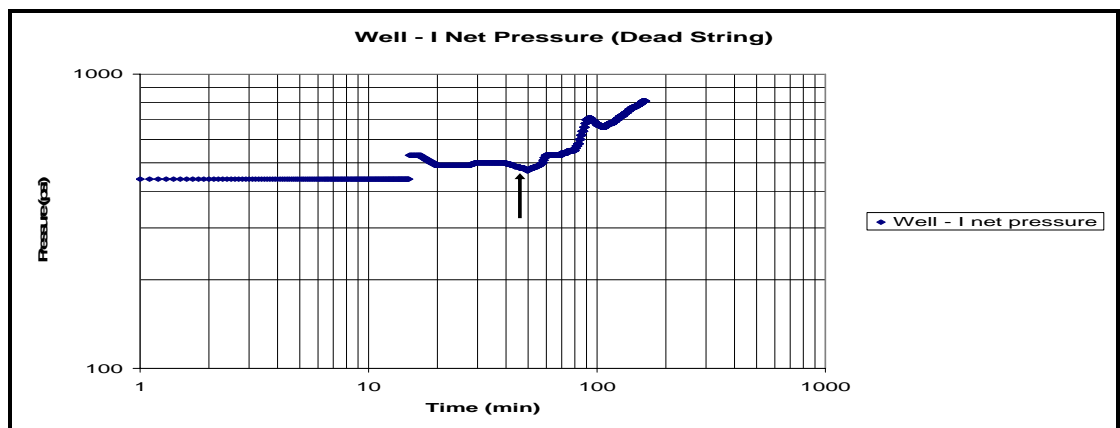


Figure 4.1: Well I net pressure (Dead String). Proppant effect is indicated by the arrow (Rogelio *et al.* 1997).

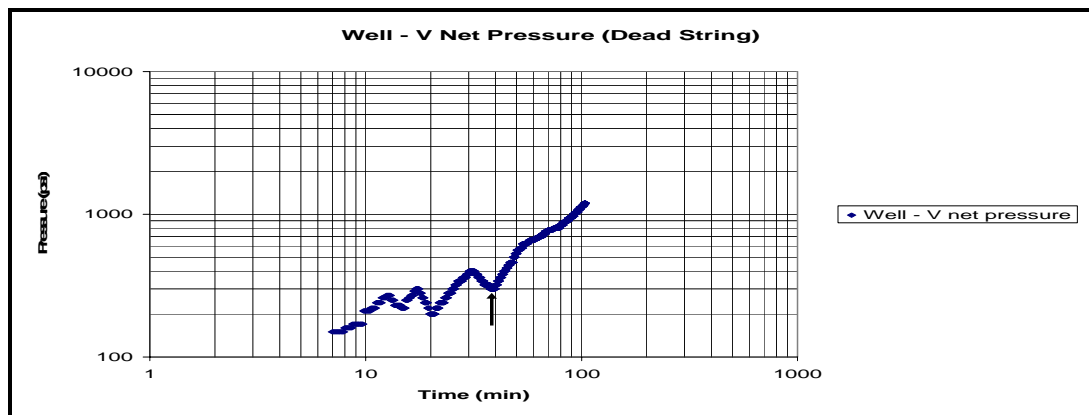


Figure 4.2: Well V net pressure (Dead String). Proppant effect is indicated by the arrow (Rogelio *et al.* 1997).

4.3.1.1 Fracture Height Measurement

To investigate the height of fracture number of techniques can be used (Davies. 2007) such as:

- Running of a temperature log after the completion of job
- Running a production log across the perforated interval to measure the flow profile
- The proppant can be given a lightly radioactive coating

Radioactive coated proppants were used in this treatment and the fracture containment of these two wells was corroborated by observing the changes of the pre-fracture with the post fracture gamma-ray as shown in **Figure 4.3** and **4.4** (Rogelio *et al.* 1997). **Figure 4.3** shows radioactive survey for well I while **Figure 4.4** shows radioactive survey of well V. It can be seen from Postfrac Gamma Ray that fracture is contained within the pay zone of well I at a depth of 1695 to 1705 meters and well V at 1415 to 1440 meters.

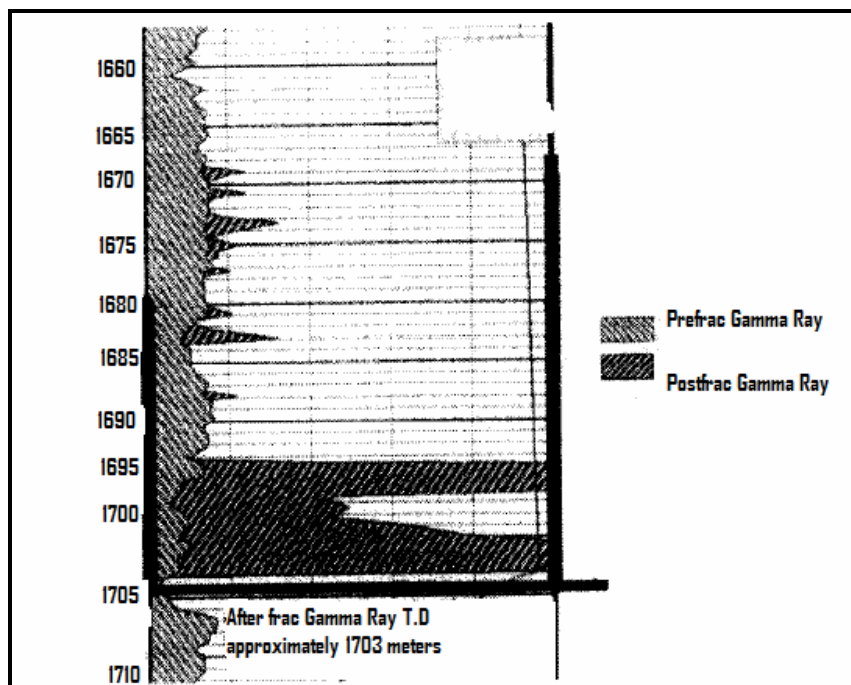


Figure 4.3: Well I pre and post fracture gamma-ray (bracketfrac) (Rogelio *et al.* 1997)

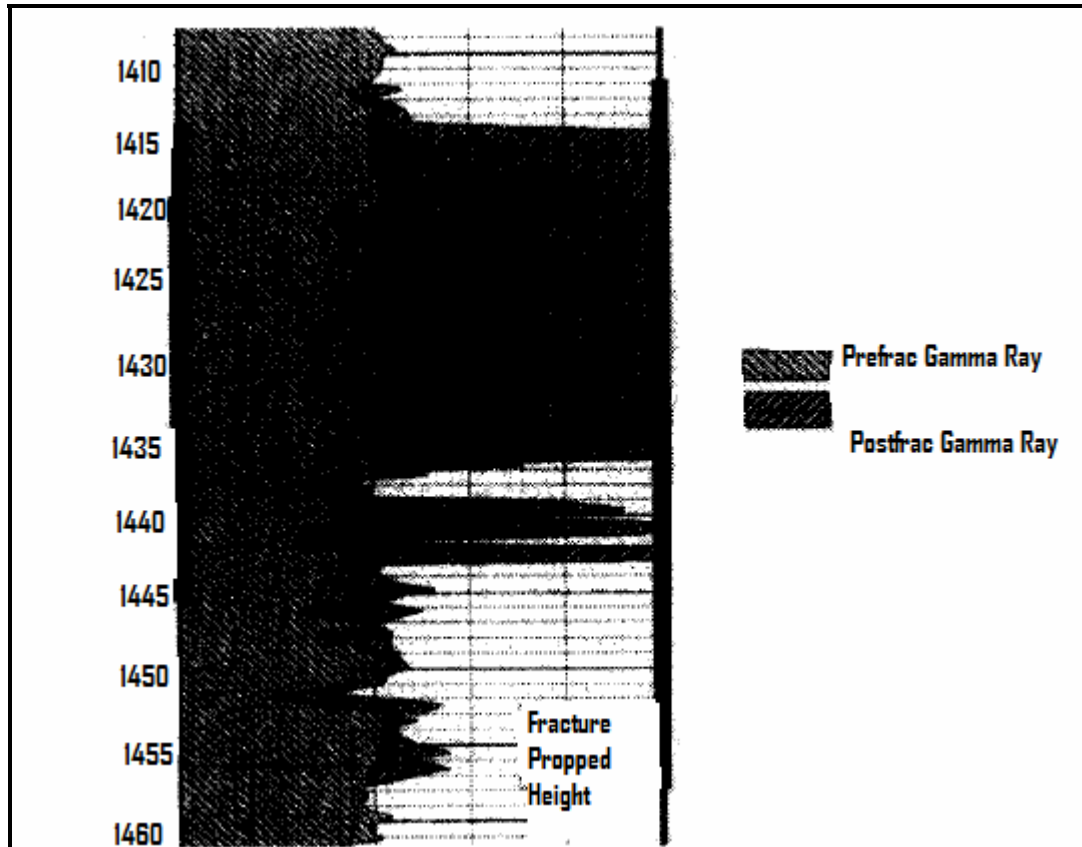


Figure 4.4: Well V pre and post fracture gamma-ray (bracketfrac) (Rogelio *et al.* 1997)

4.3.2 Well – III and IV

These wells were suffering with upward height growth because of the weak adjacent formation. Therefore, Wells III and IV were fractured with control of upward height growth (named as invertfrac). In both cases 450 lbs of light weight diverting material were used to attempt to arrest upward growth. Table shows that initially 450 lbs of diverting agent is pumped which will settle at the across the upper layer and will create a barrier. After pumping this there is shut-in period of 120 minutes which is to time required for the barrier to settle and finally the main treatment will be pumped. It can be seen that the same fluid will be used for the treatment i.e HPG – 20 lb Gel and HPG – 40 lb crosslinker at a rate of 4 and 16 barrel per minute (bpm). The fracturing schedules for these cases are provided in **Tables 4.4** and **4.5**.

Table 4.4: Well III invertfrac and fracture pumping schedule (Rogelio *et al.* 1997)

Pumping Schedule Well III			
450 lbs of diverting agent			
Fluid Volume (Gallons)	Fluid Type	Pumping Rate (bpm)	Stages
3500	HPG-20 LB GEL	16	Prepad
1700			0.25 PPA INVERTFRAC
2500		4	Flush
Shut-in for 120 minutes			
10000	HPG-20 LB GEL	16	Prepad
25000	HPG-40 LB X-LINK GEL		Pad
2000			1 PPA LWP Plus 12/20
3000			2 PPA LWP Plus 12/20
4000			3 PPA LWP Plus 12/20
6500			4 PPA LWP Plus 12/20
8000			5 PPA LWP Plus 12/20
8500			6 PPA LWP Plus 12/20
9000			7 PPA LWP Plus 12/20
3000			8 PPA LWP Plus 12/20
1500			9 PPA AcFrac PR 12/18
1100			HPG-20 LB GEL

Table 4.5: Well IV invertfrac and fracture pumping schedule (Rogelio *et al.* 1997)

Pumping Schedule Well IV			
450 lbs of diverting agent			
Fluid Volume (Gallons)	Fluid Type	Pumping Rate (bpm)	Stages
3500	HPG-20 LB GEL	15	Prepad
1700			0.25 PPA INVERTFRAC
2500		4	Flush
Shut-in for 120 minutes			
10000	HPG-20 LB GEL	15	Prepad
25000	HPG-40 LB X-LINK GEL		Pad
3000			1 PPA LWP Plus 12/20
3000			2 PPA LWP Plus 12/20
4000			3 PPA LWP Plus 12/20
5000			4 PPA LWP Plus 12/20
6000			5 PPA LWP Plus 12/20
7000			6 PPA LWP Plus 12/20
9000			7 PPA LWP Plus 12/20
4300			7 PPA AcFrac PR 12/18
5000			8 PPA AcFrac PR 12/18
1300	HPG-20 LB GEL		Flush

Again net pressure has been used to investigate the fracture height control. **Figure 4.5** shows net pressure profile for well – III. Negative slope in the net pressure (from the dead string) for the first 30 minutes is observed which changes to positive slope till 45 minutes and then again negative slope is observed. Note that after 60 minutes a positive slope is maintained mainly as the result of proppant bridging at the diverting material. The signature from the net pressure for well – IV is shown in **Figure 4.6**. It indicates

that initially the fracture is propagating either in a radial mode or from a line source generating height growth. This is corroborated from the tendency of the dead string pressure during the first 8 minutes. Following this containment and propagation are observed until the effect proppant bridging at 50 minutes from the invertfrac diverting material is clearly observed.

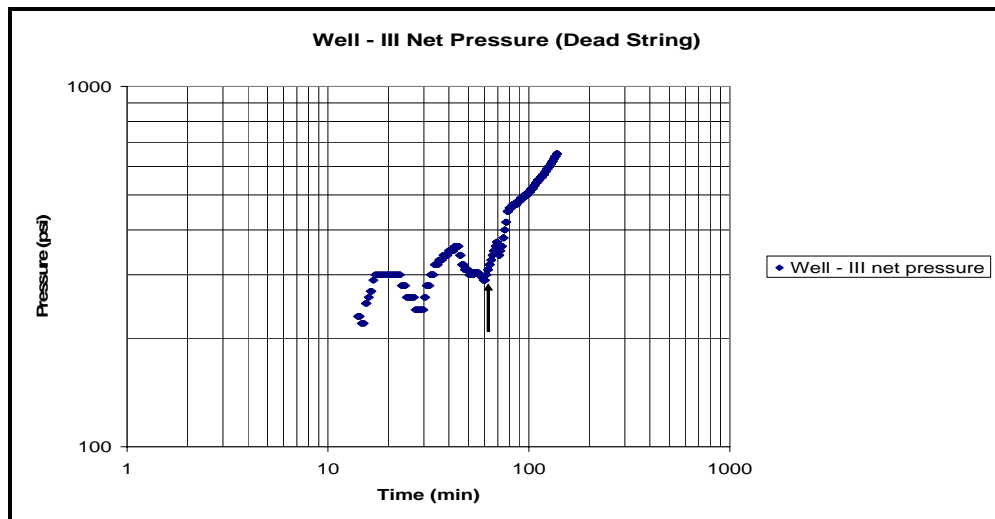


Figure 4.5: Well III net pressure (Dead String). Proppant effect is indicated by the arrow (Rogelio *et al.* 1997).

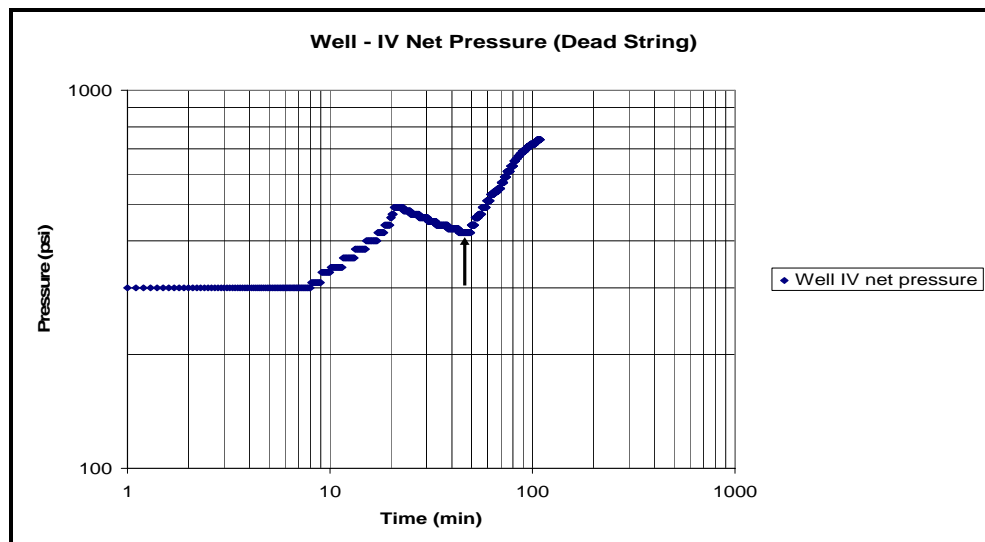


Figure 4.6: Well IV net pressure (Dead String). Proppant effect is indicated by the arrow (Rogelio *et al.* 1997).

Similarities can be seen in the net pressure behavior of both wells treated with invertfrac Figure 4.5 and 4.6. In both cases following the arrival of proppant containment from the effect of the diverting material is observed.

The behavior of the net pressure correlates well with the upward fracture growth and the final containment of the fracture as observed in **Figure 4.7**. It can be noted that the fracture grew 12 meters above the top of the perforated interval before containment was achieved.

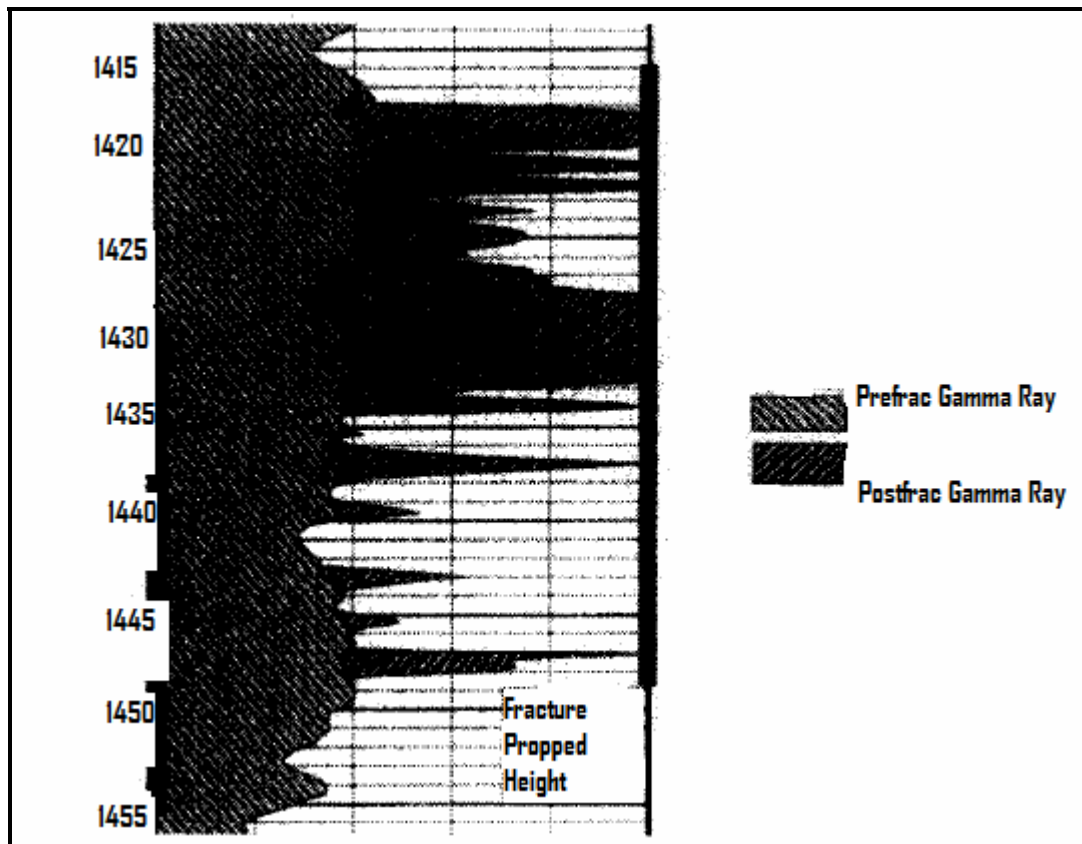


Figure 4.7: Well III pre and post fracture gamma-ray (invertfrac) (Rogelio *et al.* 1997)

Well-IV with invertfrac was tagged with three different tracers in an effort to determine different tendencies and preferences of height growth. In this well the results from the gamma-ray as shown in **Figure 4.8**, indicates a contained fracture between 1620 and 1647 meters with no preference of down or upward growth from the different stages.

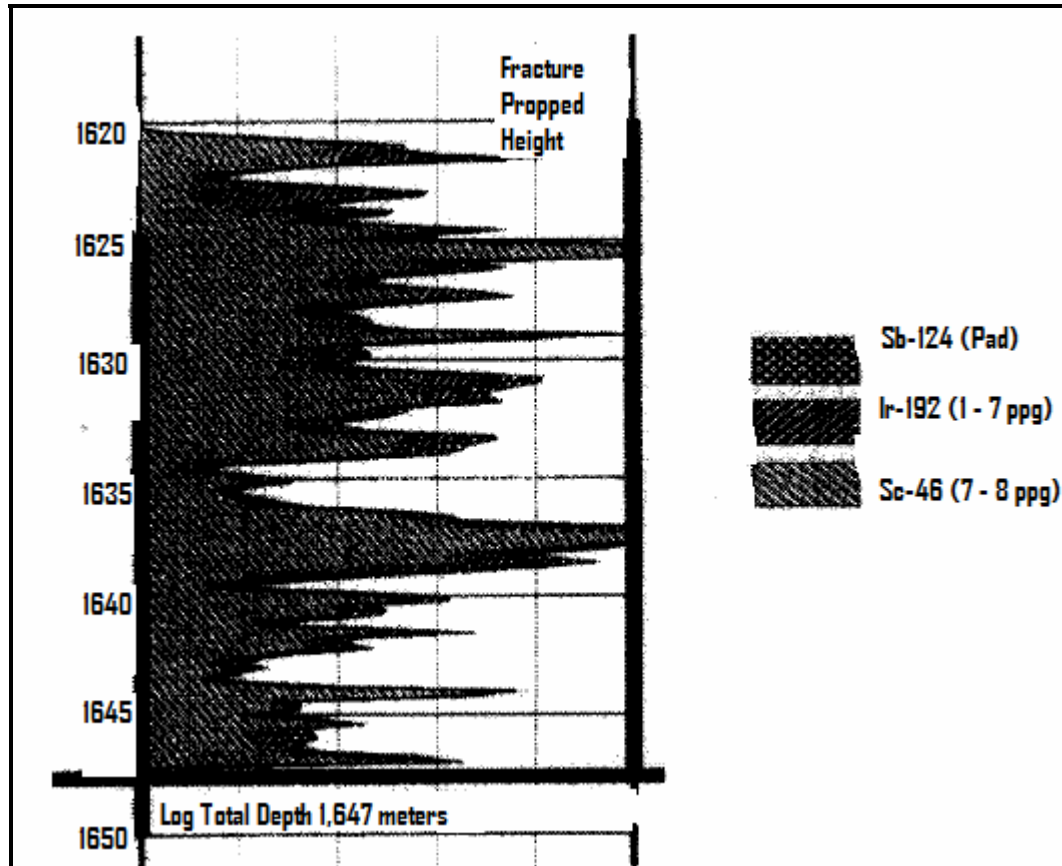


Figure 4.8: Well IV pre and post fracture gamma-ray (invertfrac) (Rogelio *et al.* 1997)

4.3.3 Well – II

Well – II was suffering with the downward height growth. However, Well – II was fractured with control of downward growth (named divertafrac). **Table 4.6** presents the treatment pumping schedule including the pre-treatment diverting stage. This was similar to that of downward diverting stages of the bracketfrac cases. It can be seen in **Table 4.6** that a mixture of sand has been pumped. Mix of 100 mesh and 20/40 mesh sand is pumped with a quantity of 2000 and 1000 lbs respectively. Shut-in period for the settlement of the diverting agent is 60 minutes and the fluid used is same as used in the first two techniques. However, rate of fluid used is 4 and 15 bpm.

Table 4.6: Well II divertafrac and fracture pumping schedule (Rogelio *et al.* 1997)

Pumping Schedule Well II			
Mix of 2000 lbs of 100 mesh sand and 1000 lbs of 20/40 mesh sand			
Fluid Volume (Gallons)	Fluid Type	Pumping Rate (bpm)	Stages
3000	HPG-20 LB GEL	15	Prepad
2000			0.25 PPA DIVERTFRAC
2000		4	Flush
Shut-in for 60 minutes			
10000	HPG-20 LB GEL	15	Prepad
26000	HPG-40 LB X-LINK GEL		Pad
2000			1 PPA LWP Plus 12/20
3500			2 PPA LWP Plus 12/20
4500			3 PPA LWP Plus 12/20
6000			4 PPA LWP Plus 12/20
7500			5 PPA LWP Plus 12/20
9000			6 PPA LWP Plus 12/20
7500			7 PPA LWP Plus 12/20
3400			7 PPA AcFrac PR 12/20
1500			8 PPA AcFrac PR 12/18
3400			8 PPA AcFrac PR 12/18
950	HPG-20 LB GEL		Flush

The behavior of the divertafrac case indicates that the fracture was growing in a control mode as shown in **Figure 4.9**. This is in fact reflected from the radioactive tagging of the proppant as shown in **Figure 4.10**. Note that in this case no change in the net pressure slope was observed upon the arrival of the proppant as in the invertafrac and bracketfrac cases.

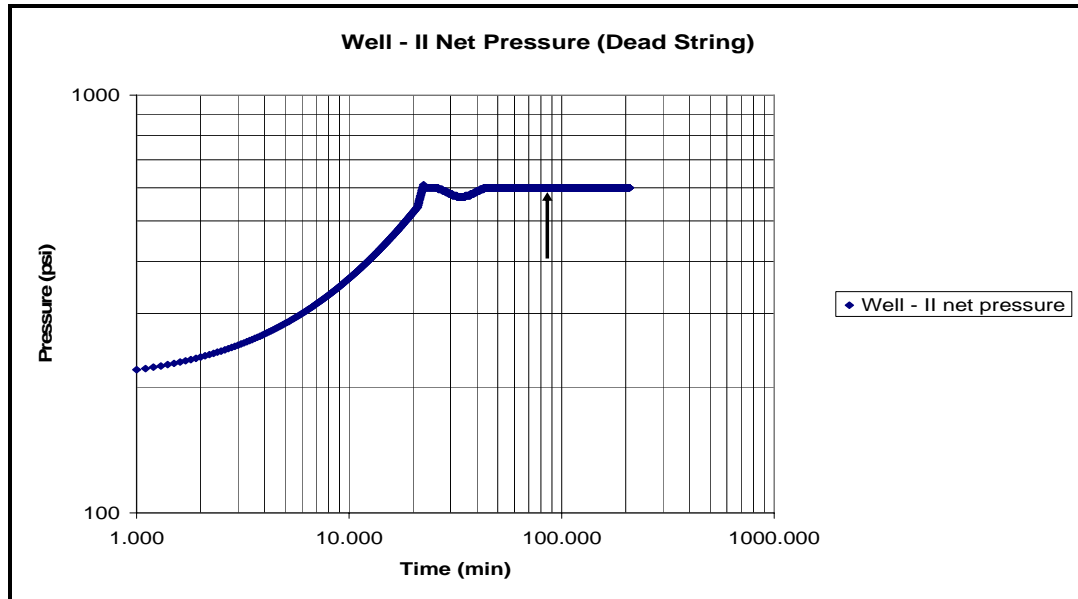


Figure 4.9: Well II net pressure (Dead String). Proppant effect is indicated by the arrow (Rogelio *et al.* 1997).

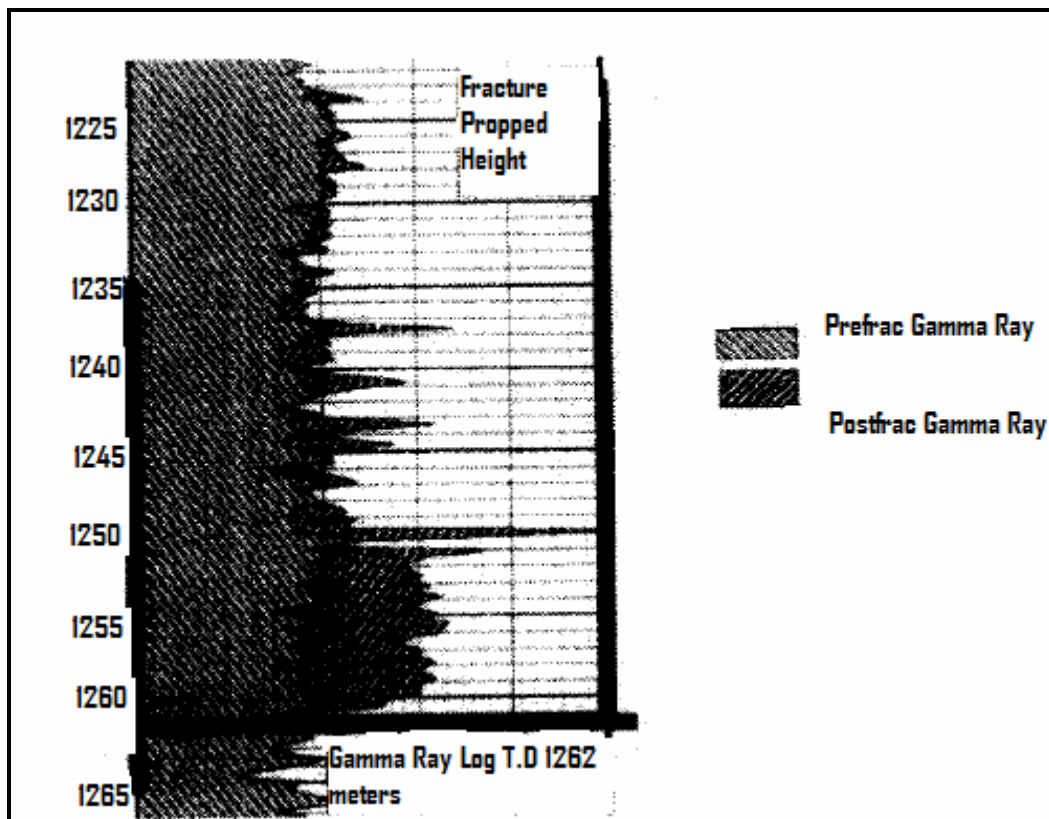


Figure 4.10: Well II pre and post fracture gamma-ray (divertafrac) (Rogelio *et al.* 1997)

4.4 PRODUCTION RESULTS

Finally response of wells I, II, III, IV and V treated by applying artificial containment to control height growth is compared with the wells A, B, C, D and E treated without height growth control. This is in effort to determine the benefit or not of fracture containment.

Figure 4.11 and **4.12** shows cumulative production for the wells treated with and without control. It can be seen that wells with complete containment (bracketfrac) have higher production after one year than those treated without control.

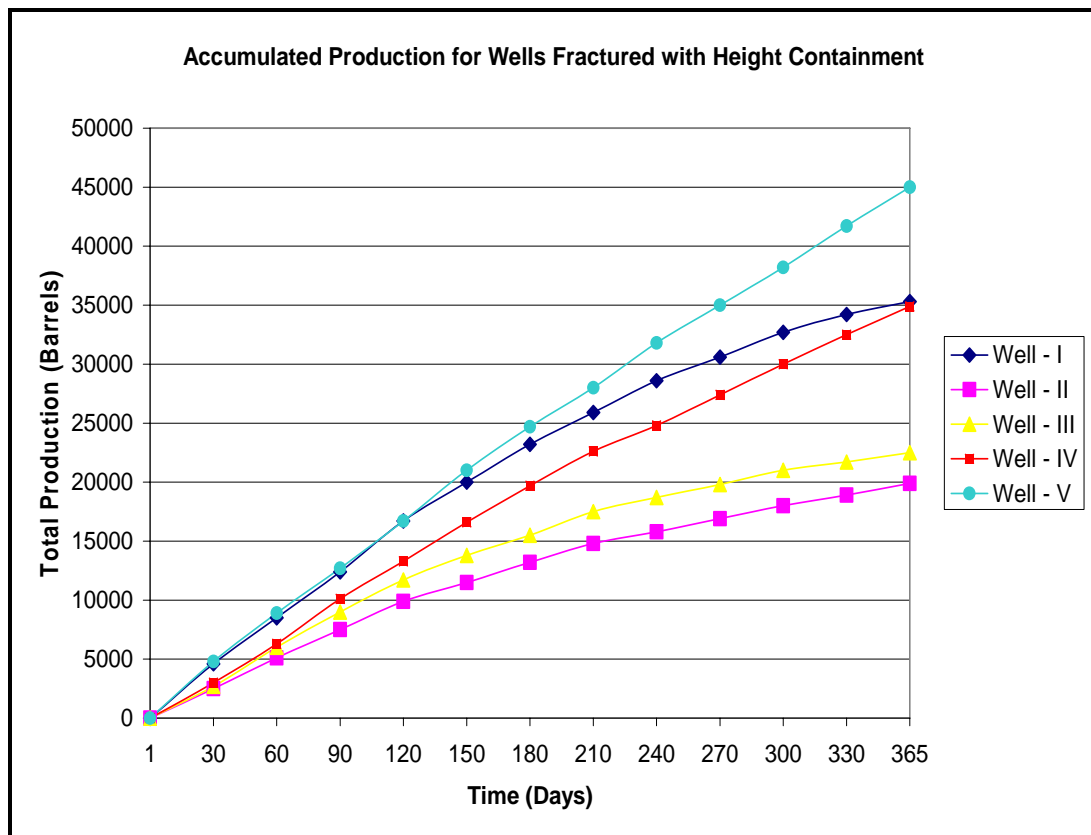


Figure 4.11: Accumulated production in one year for wells fractured with height containment (Rogelio *et al.* 1997)

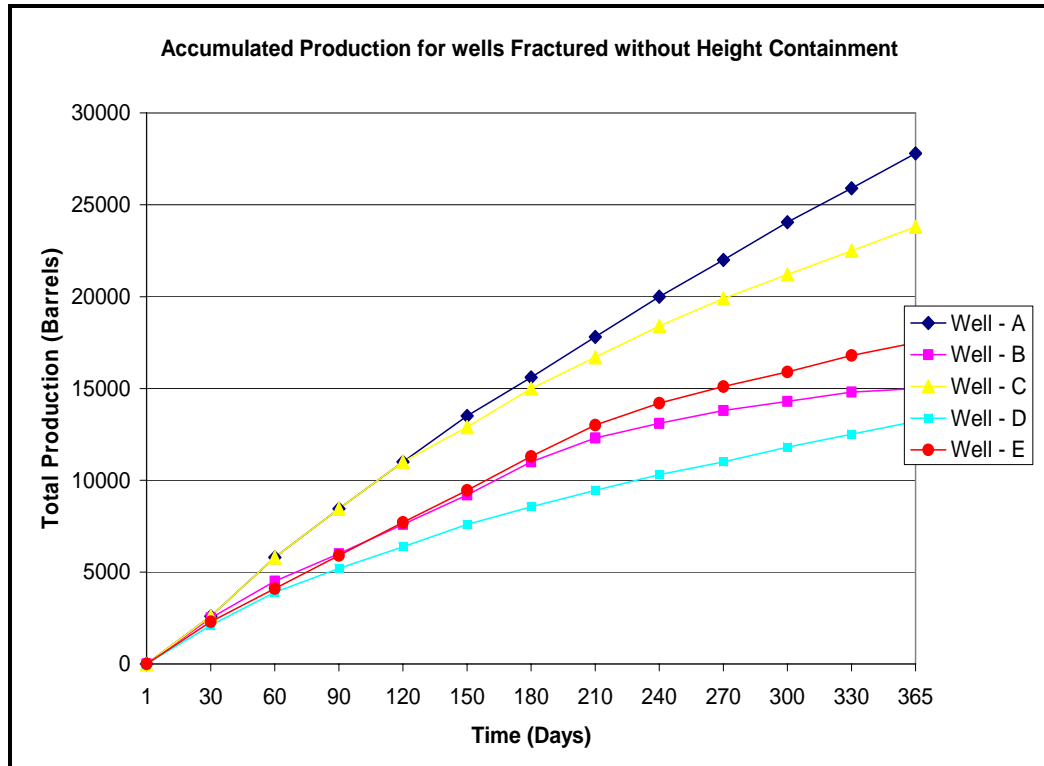


Figure 4.12: Accumulated production in one year for wells fractured without height containment (Rogelio *et al.* 1997)

Figure 4.13 shows average cumulative production after one year for wells fractured by applying control versus wells treated without control. As can be seen from the cumulative production profile that wells treated using height growth produced a total of 40,000 bbls while the wells treated without containment has only produced 17500 bbls of oil. From this figure it is clear that the gain in production achieved as a result of artificial control of fracture height growth.

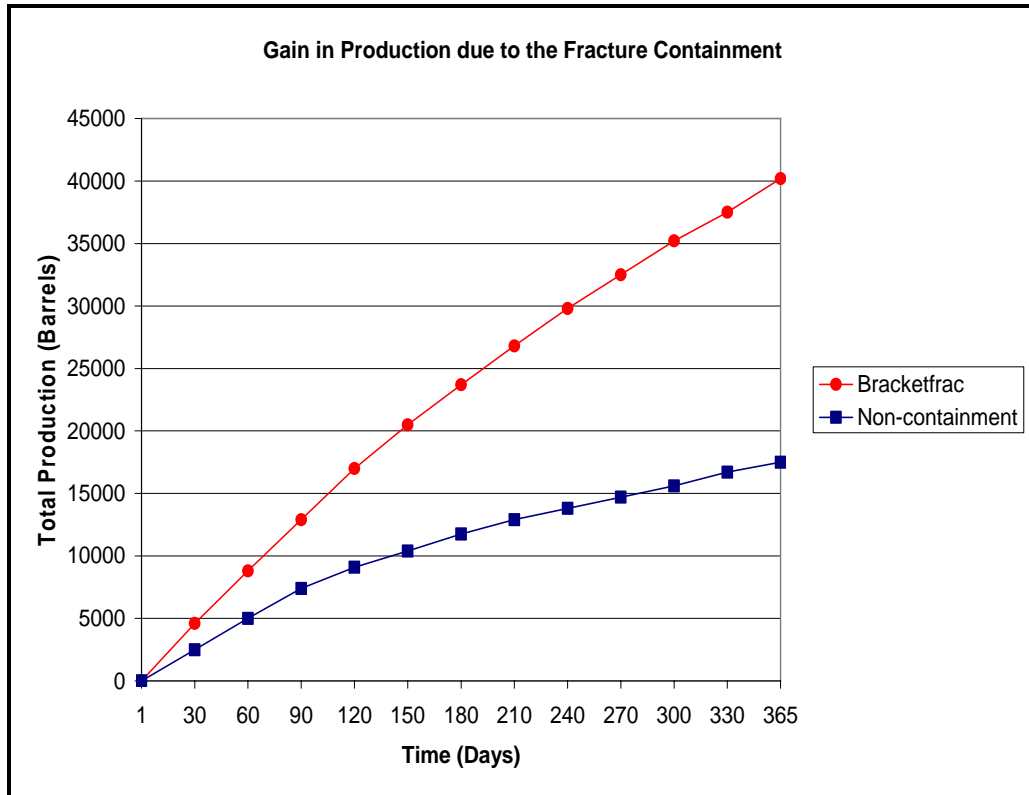


Figure 4.13: Gain in production from fracture containment to the production interval (Rogelio *et al.* 1997)

4.5 CASE HISTORY – 2 EAST TEXAS FIELD

4.5.1 Introduction

Fracture height containment has plagued operators in East Texas for years (Arp *et al.* 1986). Fracturing of producing intervals, such as the Georgetown, Buda, Woodbine, Travis Peak and Petit Lime has resulted poor production in many cases. This poor production may be attributed to fracturing out of the zone (Arp *et al.* 1986).

Common techniques previously employed in East Texas include:

1. Fracturing with compressible (N₂ foam) fluids
2. Reducing treatment injection rates to limit pressure applied to barriers
3. Restricting fluid viscosity and density to minimize pressure applied to barriers

4. Combination of the above

After completing a series of wells operator was having problems pumping frac jobs to completion. The project analyzed the reservoir and previous treatment records and determined that reservoir barriers were incapable of confining the fracture within the pay zone. Therefore, a study was conducted by comparing wells fractured using artificial barriers with wells fractured without barriers (Arp *et al.* 1986).

For comparison two wells were treated with and without applying artificial barriers having similar formation transmissibility. Well information data is in **Table 4.7**.

Table 4.7: Information data for wells (Arp *et al.* 1986)

Well No	1	2
Bottom-Hole Static Pressure (psi)	5120	4850
Porosity (%)	16	20
Permeability (md)	0.4	2.3
Formation Thickness (ft)	31	6
Kh (md-ft)	12.4	13.8
Casing Diameter (in)	5.5	5.5
Tubing Diameter (in)	2 7/8	2 3/8
Depth to the top of formation (ft)	9500	9470
Fracture Gradient (psi/ft)	0.70	0.70
Formation Type	Sandstone	Sandstone
Young's Modulus (psi)	3.0E+06	3.0E+06
Reservoir fluid compressibility (psi ⁻¹)	2.20E-5	2.20E-5
Reservoir fluid viscosity (cp)	0.20	0.20
Formation volume factor (bbl/stb)	1.90	1.90

It can be seen from Table 4.7 that both wells have almost same reservoir and mechanical properties. As shown that permeability of two wells ranges from 0.4 to 2.3 mD

therefore, wells are possible candidates of hydraulic fracturing. One of the main parameter which controls the height growth is young's modulus. Notice that young's modulus is same for the both wells therefore; growth will be same in both wells. Well no. 1 used buoyant diverter service for the barrier while well no. 2 did not (Arp *et al.* 1986).

Figure 4.14 below is log of well no. 1 having SP and induction logs. Well has been drilled in Travis Peak formation and was perforated from 7840' – 7850' with 11 feet of pay zone as shown in **Figure 4.14**. Well has a very small pay zone and notice that water is evidenced by high conductivity above and below the pay zone on the induction log.

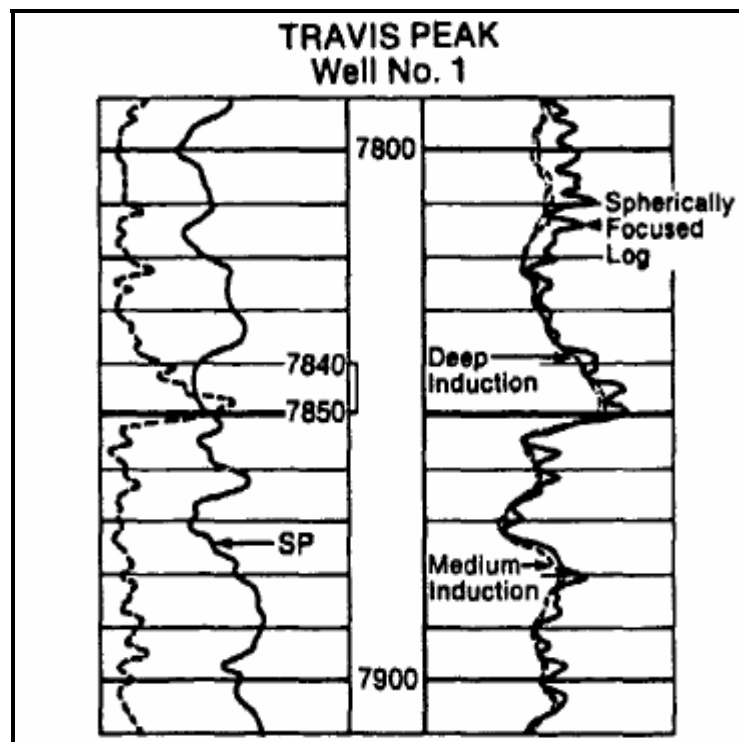


Figure 4.14: Openhole log for well no. 1 (Arp *et al.* 1986).

On the other hand well two has been drilled and perforated in Petit Lime formation. Petit Lime of East Texas often has water situated closely to pay zones. The field has a small pay zone with water indicated in dual induction/SP log as shown in **Figure 4.15**.

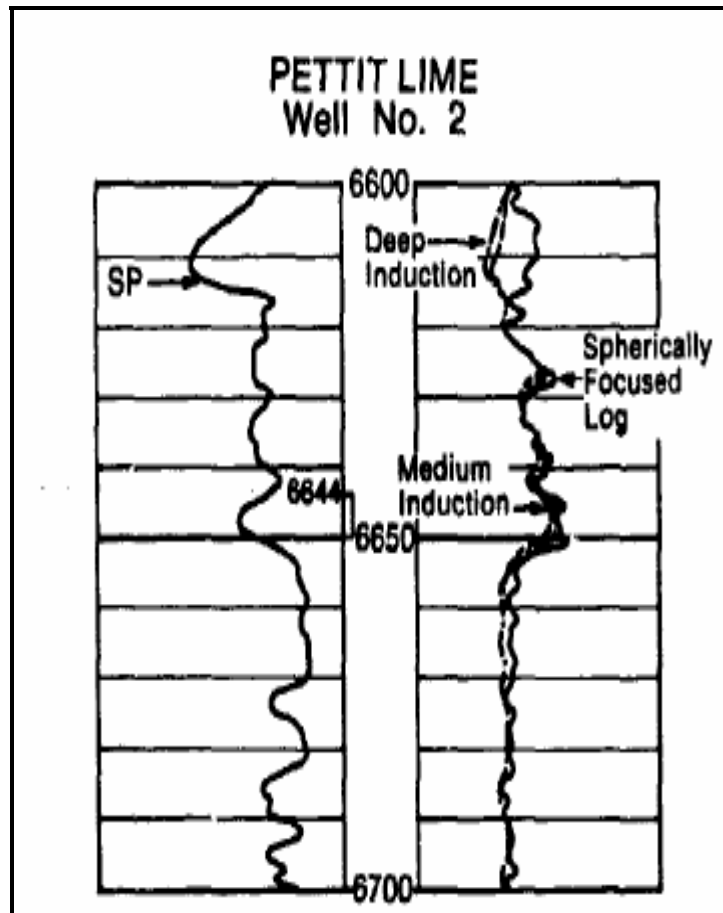


Figure 4.15: Openhole log well no. 2 (Arp *et al.* 1986).

By interpreting logs of two wells it is evidenced pay zone are very small and if fracture is not contained in the pay zone it may enter the water zone.

The designed fracture length of well no. 1 was 800 ft and for well no 2 was 580 ft. The fracturing schedules for the two wells are provided in **Tables 4.8** and **4.9**.

Table 4.8: Well I fracture pumping schedule (Arp *et al.* 1986).

Pumping Schedule Well No. 1			
Fluid Volume (Gallons)	Fluid Type	Pumping Rate (bpm)	Stages
3000	Crude Oil	8	Prepad
6000			Pad
2000			Pad
1000			0.10 lb/gal Diverter
1000			0.25 lb/gal Diverter
1000			0.50 lb/gal Diverter
1000			1.00 lb/gal Diverter
2400			Flush
Shut-in for 60 minutes while artificial barrier forms			
5000	Gelled Oil	12	Prepad
4000			Pad
32000			0.5 lb/gal 100 mesh sand
4000			Spacer
1000			1 lb/gal 20/40 Ottawa
2500			2 lb/gal 20/40 Ottawa
3000			3 lb/gal 20/40 Ottawa
3000			4 lb/gal 20/40 Ottawa
3000			5 lb/gal 20/40 Ottawa
3000			6 lb/gal 20/40 Ottawa
6000			8 lb/gal 20/40 Ottawa
2400			Crude Oil

Table 4.8 shows that well is treated using diverting agent. Diverting agent has been pumped initially using crude oil as fracturing fluid and at a rate of 8 barrels per minute (bpm). After completion of pumping diverting agent pumps are shut-in for 60 minutes to

settle the diverting agent. Next step is to pump the main treatment. For main treatment pre-pad was pumped which consists of crude oil, followed by gelled oil at a rate of 12 bpm and finally proppant (Ottawa sand) at a rate of 12 bpm.

Table 4.9 shows treatment schedule for the well no. 2. Notice that there is no diverting agent used in this well as illustrated before. Therefore, main treatment has been pumped from the start of the job. Treatment consists of pre-pad i.e. crude oil at a rate of 10 bpm followed by pas consists of gelled oil at the same rate and finally proppant has been pumped at rate greater than that used for pre-pad and pad.

Table 4.9: Well 2 fracture pumping schedule (Arp *et al.* 1986)

Pumping Schedule Well No. 2			
Fluid Volume (Gallons)	Fluid Type	Pumping Rate (bpm)	Stages
15000	Crude oil	10	Prepad
3000	Gelled oil		Pad
18000		12.5	0.5 lb/gal 100 mesh sand
6000		12.8	Spacer
2000		10.5	2 lb/gal 20/40 Ottawa
3000		12	4 lb/gal 20/40 Ottawa
4800		10.3	6 lb/gal 20/40 Ottawa
Screened out with 35,000 lb sand in formation			

Fracture length calculated, based on the post fracture performance evaluation was 782 ft for well no.1 while for well no. 2 the job was screened out after placing 49 % of the proppant in the formation. Only 290 ft of effective penetration was achieved as a result of this conventional treatment.

4.5.2 Production Results

After treatment has been completed, both wells have been put on production. **Figure 4.16** shows the cumulative production of both wells. Notice that well fractured using artificial barrier has cumulative production of 47000 bbl after 150 days of production while well treated without barrier has only produced 17000 bbls of oil. Which means that the well used buoyant diverter produced over 30,000 additional barrels of oil.

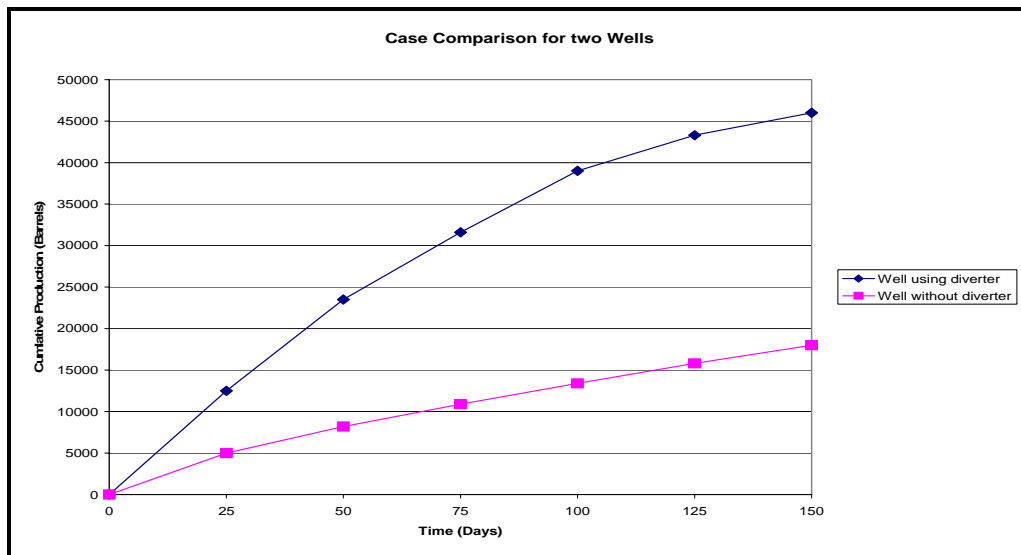


Figure 4.16: Cumulative production vs Time (Arp *et al.* 1986)

4.6 CASE STUDY – 3

4.6.1 Introduction

As discussed earlier in chapter 2 that one of the challenge in hydraulic fracturing is fracture conductivity which is dependent on different factors. This case study is discussing one of the factors responsible for reduction/improvement in fracture conductivity i.e. **Type and Strength of Proppant**.

A study was conducted by Rightmire *et al.* 2005, showing “**the effects of proppant selection upon well productivity**”. Analysis suggests that significantly greater economic return has been achieved when fracture designs are optimized. In their study

the most common design was 132,000 lbm of proppant was placed with a hydrocarbon-based fluid. For this treatment design, the average first year production for wells receiving 132,000 lbm of **sand** was 302 MMscf of gas. Wells stimulated with 132,000 lbm of **ceramic** proppant averaged 420 MMscf, during the first year. Benefits vary with job size, fluid type and other factors. The incremental cost of ceramic proppant is usually recovered within 30 days, generating a significant increase in profitability. At current gas prices, average return on investment achieved by optimizing proppant selection greatly exceeds 100%.

Atteberry *et al.* 1979 reported, evaluation of the performance of most reservoirs revealed that initial rates after fracturing exhibited significant increases over prestimulation capacity. However, it became evident shortly after going on production that several geopressured zones experienced severe and continuous decline in capacity following fracture stimulation. Consequently, projected estimates of ultimate gas recovery proved disappointing in comparison to earlier expectations.

Assessment of the cause of obvious fracture deterioration pointed to possible embedment of the proppant in the formation allowing the fracture to close. Another option proposed that the sand historically used as proppant had collapsed allowing fracture deterioration as a result of closure and plugging of channels by crushing sand. Also the problem could include a combination of embedment and crushing of proppants (Atteberry *et al.* 1979).

As the relative strength of the various materials increases, so too have the respective particle densities, ranging from 2.65 g/cc for sands to 3.4 g/cc for the sintered bauxite. As the density increases, so does the difficulty in placing that particle evenly throughout the created fracture geometry. Excessive settling can often lead to bridging of the proppant in the formation before the desired stimulation is achieved. The lower particle density reduces the fluid velocity required to maintain proppant transport within the fracture which in turn provides for a greater amount of the created fracture area to be propped. Alternatively, reduced density proppants could be employed to reduce fracturing fluid complexity and minimize proppant pack damage (Rickards *et al.* 2003).

The possibility of proppant collapse led to research of available proppants/techniques exhibiting tolerance to extreme stress conditions. One of the latest technique, proposed by (Rickards *et al.* 2003), is placement of high strength ultra-lightweight proppant.

4.6.2 Case History

In the spring of 2003 a number of stimulation treatments were performed whereby a new class of ultra-lightweight proppants (ULW-125) with low specific gravity (S.G ~ 1.25) was pumped in various fracturing fluids with close to 1 centipoise viscosity. In most cases the base fluid was 10 ppg brine, so the settling rate of the proppant was very low or negligible (Chambers *et al.* 2005).

The diamond M Field, discovered in 1949, is located about 12 miles southwest of Snyder, Texas. For comparison wells were fractured treated using ultra-lightweight and conventional fracture treatment.

Using the lengths and heights from the microseismic mapping results, and assuming the height is constant from tip to tip, total fracture face area was calculated for the two wells. (Total surface area would be length x height x 2, to account for both faces of the fracture). Total calculated surface area from the ULW – 125 treatment is 1,390,000 square feet. Total calculated surface area for the borate treatment is 695,000 square feet. On a percentage basis, the ULW – 125 fractures exposes 100% as much surface area than the conventional fractures.

A simple approach was used to determine conductivities. Calculated surface areas for one face of the fracture divided by the pounds of proppant placed in each well, gives an average pounds per square foot of proppant concentration.

Thus,

In one well, 32,500 lbs of ULW – 125 divided by 695,000 ft² yields 0.047 lbs/ft². In other well, 158,000 lbs of brown sand was pumped and dividing by 347,000 ft² of surface area yields 0.45 lbs/ft². With 2000 psi closure stress, conductivity of ULW – 125

at this concentration approaches 10,000 md-ft. At 0.047 psi/ft² and 2000 psi closure stress, conductivity is approximately 6,500 md-ft.

4.7 CASE STUDY – 4

4.7.1 Introduction

Polymers are widely used in stimulation applications as additives to provide friction reduction, viscosification, particle transport and fluid loss control. The residual effects of the insufficient degradation of polymers utilized in hydraulic fracturing have been identified as a primary contributor to permeability damage. Damage to the formation and/or proppant pack permeability can significantly decrease the hydrocarbon deliverability and hence impair well productivity.

If a hydraulic fracturing treatment fails due to formation damage then the choices to rectify the situation are obvious:

1. Tolerate the reduced well productivity
2. Attempt to re-stimulate the reservoir or
3. Perform a treatment to remove the polymeric damage and achieve the potential fracture permeability of the proppant placed.

Acceptance of less productivity than that of which the well is capable is often not economically viable. Depending on the reservoir characteristics, the size of the original stimulation placed and the specific of the treatment inadequacy a re-fracture of the zone may not be feasible and is likely to be at least as costly as the original treatment. The application of cost effective remedial treatment to remove the polymeric damage in the existing propped fracture is an attractive option.

As stated earlier in chapter – 2 that the first polymer used was Guar which is a naturally occurring polysaccharide. It was reacted with propylene oxide to form HPG. Laboratory tests have indicated that different polymers used have different percentage of proppant

pack permeability damage. Tests (Wine *et al.* 1989) shows HPG had only 1 – 3 weight percent residues, whereas guar exhibited 8 to 13 % residues.

In 1984, Almond and Bland performed a study and reported that guar and HPG produced similar proppant pack damage (18% HPG vs. 20% guar @ 20 °F). Penny *et al.* 1987 has shown both guar and HPG yield similar conductivity impairment.

To remove this polymeric damage few techniques have been proposed by different authors (Norman *et al.* 1989, Chueng *et al.* 1989).

4.7.2 Enzymes to remove Polymeric Damage

One of the technique introduced breaker technology utilizes polymer linkage specific enzyme complexes to hydrolyze the polymer to non-damaging fragments; ideally to completely soluble simple sugars. The enzyme systems are not reactive with substances other than the targeted polymers. Neither the crosslinker type nor polymer derivatization interferes with the ultimate degree of enzymatic degradation of the polymer backbone is the same.

The treatment employs a concentrated polymer-linkage specific enzyme complex in a potassium chloride brine solution. Surfactants are usually added to reduce surface tension and promote the aqueous load recovery. Other additives such as non-emulsifiers, iron control agents, pH control agents and the like may be added optionally as deemed necessary. Field application is shown in case histories below (Brannon *et al.* 1995).

4.7.3 Canyon Sand Formation Case History

A study was conducted on Canyon Sand gas well in Crockett County, Texas. The perforated interval was 6,230' – 6410' and the Bottomhole Static Temperature was 160 °F. The well was stimulated with 165,000 gallons of a guar-borate fracturing fluid containing ammonium persulfate breaker to place 460,000 pounds of 20/40 Ottawa sand. The post treatment evaluation indicated that the breaker solution utilized had been mixed days before due to a job delay and was likely degraded. The load recovery was significantly less than normally experienced in the area. The post fracturing stabilized

production was 85 Mcfpd, about half the average of 160 Mcfpd observed from the offset wells. The analysis of the produced water samples indicated the presence of polymeric fragments at a high concentration (Brannon *et al.* 1995).

4.7.3.1 Treatment for damage removal

A guar-specific enzyme treatment of 5000 gallons fluid foamed with 280,000 scf nitrogen was pumped into the well at 10 barrels per minute (bpm). The treatment pressure was 3400 psi which was below the original 3800 psi fracture pressure. After deployment, the well was shut-in for two hours before flowback was initiated. The stabilized production rate one month after the remedial treatment was 135 Mcfpd, a 60% improvement. However, for nine months after the treatment the production continued to slowly improve before stabilizing at 255 Mcfpd. The continuing improvement over nine months indicates the long-term reactivity of the enzymes degradants. The three folds improvement relative to the pre-treatment production rate as shown in **Figure 4.17** is more than half – of the offset wells average production of 160 Mcfpd. This indicates potential residual damage in the offset wells (Brannon *et al.* 1995).

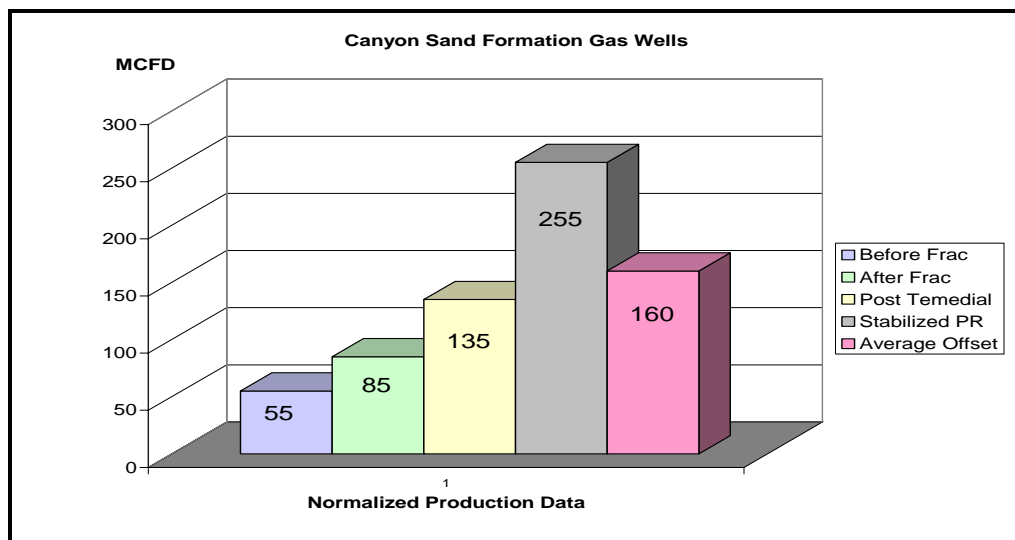


Figure 4.17: Canyon formation gas wells 9 month production data treated with guar specific enzymes (Brannon *et al.* 1995).

4.7.4 San Andres Formation Case History

A San Andres well in Lean County, New Mexico had been fractured using borate-crosslinked guar fluid, utilizing an encapsulated persulfate breaker. Bottomhole shut-in temperature is 85 °F at the 3500” interval. The well produced 10 barrels of oil per day (BOPD) prior to the fracturing treatment. The stimulation provided disappointing results, producing only 15 BOPD compared to 95 BOPD exhibited by offset wells. Poor load recovery was observed and a high concentration of polymer fragments were identified in water samples produced by the well.

4.7.4.1 Treatment to remove polymeric damage

A 3000 gallons guar-specific enzyme remedial treatment foamed to 70 quality with nitrogen was pumped and the well was then shut-in for two hours. The stabilized production rate one week after the treatment had improved greater than 500% to 84 BOPD. After 12 months, the well was producing 105 BOPD, even better than the offset wells as shown in **Figure 4.18**.

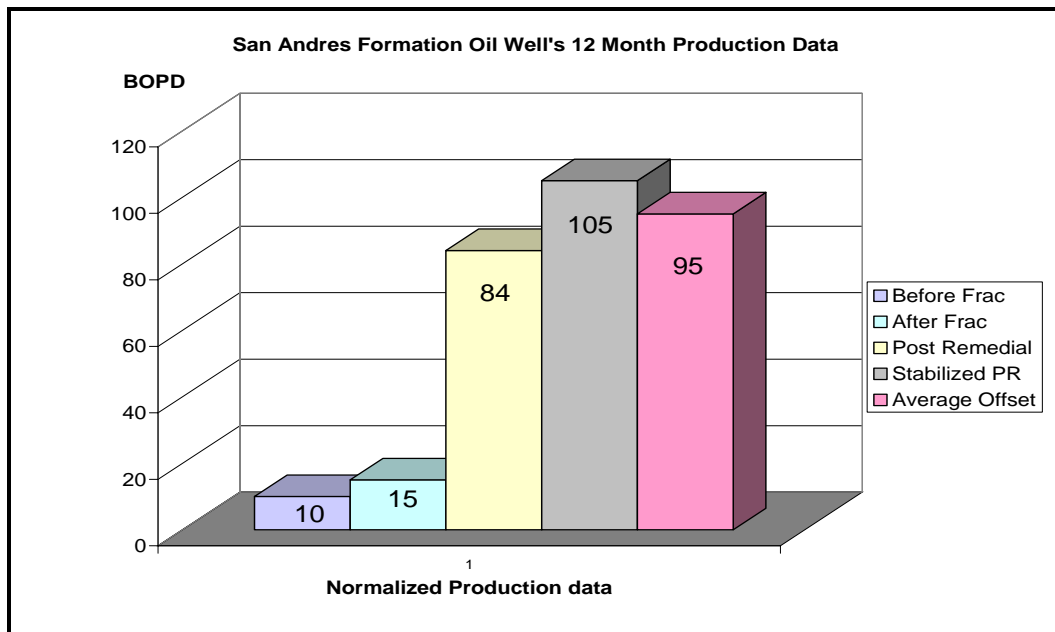


Figure 4.18: San Andres formation oil wells 12 month production data treated with guar specific enzymes (Brannon *et al.* 1995).

4.7.5 Devonian Formation Case History

A Devonian formation oil well in Andrews County, Texas had been fractured using borate-crosslinked guar fluid, utilizing an encapsulated persulfate breaker. The perforated interval was 11,062' – 11,386' with a bottomhole static temperature of 170 oF. The well flowed at 20 BOPD prior to the fracturing treatment. The well was swabbed to initiate kick-off post-frac but was very sluggish and consequently was placed on a rod pump. After several weeks, the well was producing only 8 BOPD on pump. A polymer concentration of 4.7 lb/Mgal was identified in water samples produced by the well.

4.7.5.1 Treatment to remove polymeric damage

An 8000 gallons enzyme treatment foamed to 70 quality with carbon dioxide was pumped into the fracture at 8 barrel per minute (BPM). The bottomhole treating pressure was about 6800 psi. the well was then shut-in overnight. The well began cleaning up immediately upon opening. One month after post treatment the well was flowing at a stabilized production rate of 72 BOPD as shown in **Figure 4.19**.

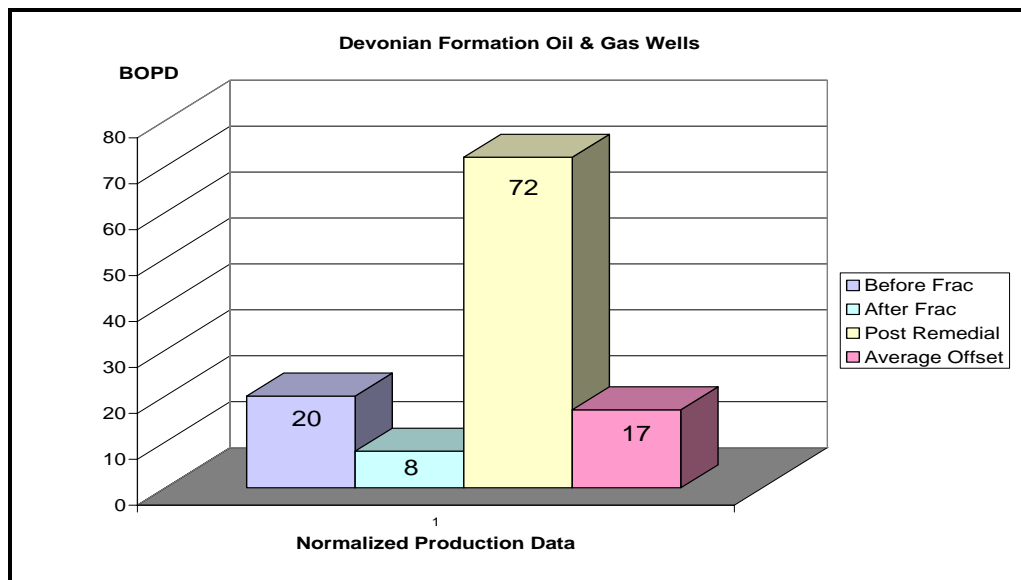


Figure 4.19: Devonian formation oil and gas wells 1 month data treated with guar specific enzymes (Brannon *et al.* 1995).

4.7.6 Viscoelastic Surfactant (VES) Treatment

In, 1997 Samuel *et al.* introduced a revolutionary fracturing fluid to the oilfield. As an alternative to the conventional polymer/breaker approach the newly developed fluid system uses a viscoelastic surfactant (VES); similar to that used in shampoos or liquid detergents to develop sufficient viscosity to create a fracture and transport proppant.

Since the introduction of the VES fluid, over 2400 successful fracturing treatments have been performed and the results from these treatments proved that VES system offers better opportunity than alternate technologies (polymer systems) to achieve long term production while utilizing much lower volumes of fracturing fluid and proppant (Samuel *et al.* 2000).

The principle advantage of viscoelastic surfactant fluids are ease of preparation, no formation damage and high retained conductivity of the proppant pack. The fluid is prepared by mixing sufficient quantity of VES in brine. Since no polymer hydrocarbon is required, the surfactant concentration can be metered continuously into the brine. No crosslinkers, breakers or other chemical additives are necessary.

4.8 Case Study – 5

For the comparison of the VES and previously stated techniques two identical offset wells were hydraulically fractured at the Mesa Verde formation at Rock Springs, Wyoming. Both wells had three zones and the bottomhole temperatures of these zones ranged between 176 °F and 190 °F. The permeabilities of the zones were between 0.03 md and 0.05 md with a fracture gradient between 0.72 to 0.95 psi/ft. These treatments were pumped through a 2 7/8" tubing at a rate of 24 to 31 bbls/min. of these two wells, one was fracture stimulated with a low guar fluid (25 lb/1000 gallons) and the other with the VES fluid (Samuel *et al.* 2000).

The logs from both wells were identical, especially in the pay zone. The first well was fracture stimulated using polymer fluid which was designed based on standard practice from past treatments in the area. The offset well with identical three zones was then

fracture stimulated with the VES fluid system. The proppant and fluid volumes used were calculated in order to achieve fracture lengths comparable to those fractured with the polymer fluid. Post-job pressure history matching on the two wells indicated that the two lower zones had fairly equivalent calculated hydraulic fracture lengths in both polymer and VES treatments (Samuel *et al.* 2000).

The major difference between the crosslinked polymer system and VES treatments is the resulting fracture height. For all treatments utilizing guar, the fracture heights were more than twice when compared to VES fluids. This is due to higher viscosity of the polymer fluid system. The polymer fluids resulted in fractures outside of the pay zones and propping open non-productive zones. With the low viscosity of the VES fluids, the fracture tends to stay confined in the pay zone. The proppant – pack conductivity is also maximized due to the non-damaging feature of the VES fluid system. These unique characteristics of the fluid can result in long effective features compared to those with polymer fluids as shown in **Figure 4.20**.

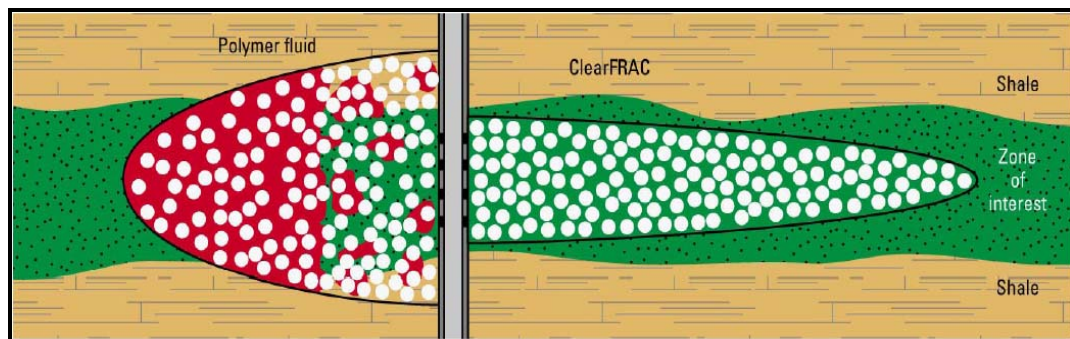


Figure 4.20: Pictorial representation of fracture half lengths obtained when stimulation treatment is performed using polymer (left and) VES (right) fluids (Samuel *et al.* 2000)

This is conformed by pressure transient studies and also from pressure history match for the various zones using fracture simulators. The results showed that similar fracture lengths could be obtained when using VES fluids by using lower volumes of fluid and proppant. Flowback results showed that the wells fracture stimulated with VES fluid

clean – up faster than the offset well fracture stimulated with the polymer fluid. Initial stabilized production from both wells showed that the wells treated with the VES fluid had better production 2.8 MMSCFD compared to 1.3 MMSCFD for the offset well stimulated with low guar fluid (Samuel *et al.* 2000).

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSIONS

Following conclusions can be derived from the analysis of case studies on fracture containment and fracture conductivity that both these seem to be the most challenging problems accounted in the fracturing treatment.

5.2 FRACTURE CONTAINMENT

One of the key challenges in hydraulic fracturing is to contain the hydraulic fracture in the pay zone (controlling vertical growth). This is especially important in thin layers. Failure to containment may cause extension of fracture into water zone underneath or an overlain gas cap which is undesirable. Especially in case of water production it is difficult to control water production. However, even if can be controlled will be at an increased cost. Major factor responsible for fracture containment is identified as the stress contrast between the adjacent layers. Teyfel *et al.* 1981 concluded that an increase of 700 psi in horizontal stress is required for complete containment in a number of limestone and sandstones.

Warpinski *et al.* 1992 found that a stress difference of 200 to 500 Psi between the pay zone and adjacent intervals were necessary to contain the fracture to their zone of interest.

It was believed for a long time that insitu stress contrast is the dominant factor responsible for the height growth. A later conducted by Hongren Gu *et al.*, 2008 suggest that stress contrast alone is not responsible for the fracture instead Young's modulus contrast is equally accountable.

5.3 FRACTURE CONDUCTIVITY

Another key challenge frequently faced in the industry is fracture conductivity. More conductive the fracture is the more productive it is. Fracture conductivity is proportional to the fracture permeability and fracture width. Factors mainly responsible for the reduction of the conductivity are:

- Type and Strength of the Proppant
- Fracturing Fluid

Proppants are used in the hydraulic fracturing treatment to keep the fracture open. However, if proppant used are of lower strength then fracture closure stress will cause crushing of the proppants. When proppants are crushed it will reduce permeability in two ways:

- Reducing width of the fracture, consequently reduce conductivity
- Migration of fines which will plug the pore spaces and consequently reduced permeability

Fracture fluid also is one of the factors which reduce fracture conductivity. Fluid used in the hydraulic fracturing is composed of various additives to attain the required rheology. However, these additives sometimes cause problems and reduce the permeability. Fracturing fluid cause reduction in the following ways:

- Polymers are used in fracturing fluid can not be completely produced back sometimes and will resultantly reduce permeability
- Fracture fluid must have the ability to transport proppants to the fracture tip
- Chemical breakers are used in the fracturing fluid to reduce the fluid viscosity after the treatment. However, if viscosity degrades before transporting proppants to the fracture tip, will cause proppant screen out.
- Fracturing fluid must also be compatible with the formation

5.4 RECOMMENDATIONS

5.4.1 Fracture Containment

- i. Knowledge of the stress and modulus contrast is very important and must be known before designing and execution of the treatment.
- ii. Fracturing fluid must be designed to keep the density of the fluid lower than the fracture gradient of the adjacent layers.
- iii. If stress contrast is lower between the layers artificial barriers must be used to prevent the fracture growth into the adjacent layers.

5.4.2 Fracture Conductivity

- i. Fracture closure stress must be known before designing and carrying out the treatment.
- ii. Proppant must be selected carefully. Proppants must have strength in excess to the fracture closure pressure to prevent proppant crushing.
- iii. Newly developed fracturing fluid viscoelastic surfactant (VES) can be used which does not use breakers and polymers.

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