Geomechanical Review of Hydraulic Fracturing Technology

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Geomechanical Review of Hydraulic Fracturing Technology

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Abstract

Hydraulic fracturing as a method for recovering unconventional shale gas has been around for several decades. Significant research and improvement in field methods have been documented in literature on the subject. The heterogeneous nature of shale has made hydraulic fracturing design to be unique for particular site conditions. Actual methods of carrying out fracturing operations and design decisions are also different for various companies in the industry. Hence, there are no standards for decisions in processes such as: formation testing, fracture modeling, choice of fracturing fluid or propping agent selection. This has led to different interpretations of pressure tests and proprietary fracture designs that have not been evaluated for adequacy against any recognized scale.

The goal of this thesis is to do an appraisal of hydraulic fracturing in theory and practice. A review is done of the early theoretical work upon which most of the current hydraulic fracturing literature is based. Effort is also made to thoroughly cover the core aspects of fracture modeling and practical operations with a view to shedding light on the strength and drawbacks of current methodologies. The thesis focuses on the geo-mechanics of the process thus less emphasis is laid on post fracturing operations. It is hoped that this will help establish the basis for a standard framework to guide fracturing design. Finally, the ambiguity of nomenclature in oil and gas circles has led to considerable confusion in conducting academic work. For this reason, effort was made in the thesis to clearly define the various terminology.

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CHAPTER ONE – DEVELOPMENT OF UNCONVENTIONAL RESOURCES

1.1 – Introduction

Hydraulic fracturing is a method of obtaining resources like natural gas and crude oil from unconventional reservoirs such as shale. Shale is termed “unconventional” because its low permeability causes difficulty in extracting resources by merely drilling into the formation. Hydraulic fracturing is not a new technique, as the first fracturing test was done in 1947 and was commercialized in 1950 (King, 2012). Another key technology, germane to shale gas development is horizontal drilling, which started in the 1930’s. The popularity of hydraulic fracturing as a means to obtain natural gas has been heightened by the large distribution of shale gas deposits in the United States. In Fig.1.1, the shale gas regions in the United States are shown. The Society of Petroleum Engineers (SPE) have estimated that in the last 60 years, about 2.5 million hydraulic fracturing operations have taken place worldwide; 1 million in the United States alone and tens of thousands of horizontal wells have been drilled (King, 2010). In this chapter, an overview of hydraulic fracturing is done, with a look at the well development process.

1.2 – The Hydraulic Fracturing Process

The hydraulic fracturing treatment follows the actual drilling and completion of the well. It starts by transportation of equipment to the site, then “rigging” them up. Rigging up means making sure all the necessary iron connections are in place, between the frac head on the well, frac pumps, manifold trailer and additives equipment (Arthur et al, 2009). Fig 1.2 shows a process flow chart of the hydraulic fracturing process. Specialized equipment are required for stimulation treatment, which include: storage tanks, chemical trucks, and a variety of pipes and fittings. Fracture tanks are large trailer tanks, designed to hold several hundred barrels of fresh water which is used as base fluid for water-based (slickwater) fracture treatments (see Fig 1.3). Additives are transported to the
site in flatbed trucks which contain pumps that enable the pumping of additives to blenders. Acid is usually transported to the fracturing site by an acid transport truck, which can hold up to 5000 gallons of acid. If the fracturing sites are closeby, acid can also be transported from site to site via backside pump. Proppants are held in large tanks called sand storage tanks, which feed proppants (usually sand) to the blender through large conveyor belts. These storage tanks may hold as much as 350,000 to 450,000 pounds of proppant (Arthur et al, 2009).

A blender retrieves fresh water from the frac tanks using suction pumps and blends the water with the proppant in a hopper. Fluids and proppant are combined with additives at design concentrations to form a slurry, which is pressurized and transferred to frac pumps. The high pressure frac pumps, transfer the slurry via positive displacement pumps to a manifold trailer. The manifold acts as a transfer station, and pumps the fluid through ground lines to the frac head (see picture in Fig 1.4) (Arthur et al, 2009). A typical massive frac site is shown in Fig 1.2d. Notice the large pit in the background were pumped out fracturing fluid is stored. Pits like these have raised huge environmental concerns about groundwater contamination. Note also the large number of fluid and proppant storage tanks, high rate blending equipment e.t.c. To set up a fracturing operation is expensive even where logistics and availability are good (Hibbeler and Rae, 2005).

Initial drilling is the same as for a conventional reservoir. A borehole is drilled vertically, then a casing is placed before cement and mud is pumped to place a barrier between the borehole and adjacent formation (see Fig 1.5). Drilling of the well is now continued, to an adequate depth within the producing reservoir, called the “kick-off point” then the well bore is deviated gradually until it curves horizontally (see Fig 1.6) and drilled a distance of typically 1000 ft to more than 5000 ft (Arthur et al, 2009).
Hydraulic fracturing is done in isolated intervals along the horizontal well (Fig 1.7) because it is impossible to apply pressure along the entire length of the well bore due to distance constraints (1000 to 5000ft). It is controlled by volume that an operator can pump into the hole at pressure. These intervals are isolated using packers. Perforations are created in the wellbore within the interval bounded by packers, using a perforating tool. In shale gas development, fracture treatment is done in several stages. Initial stages could involve just pumping freshwater into the wellbore, thereafter using an acid flush to clean cement and mud from the wellbore to ensure fluid flow is not impeded during fracture treatment (Arthur et al, 2009). In some fracture treatments, acid is pushed through the perforated interval to help breakdown the formation surrounding the wellbore.

The fracturing fluid is pumped through the perforated intervals at high pressures in order to create fractures in the surrounding formation (pay zone). Hard particles commonly known as proppants, are added to the fracturing fluid and pumped into the formation after the fractures have been created. The proppant size and concentration is increased in stages over the entire course of one treatment. The propping agents hold open the newly created fractures, to facilitate hydrocarbon recovery. The design of fracture treatment is a complex task, which involves analysis, planning, experience and rigorous observation of different stages in the entire process. Cipolla and Wright (2007), outline the following questions considered in fracturing operation:

1. Do fractures effectively cover the pay zone?
2. Are fractures confined to the pay zone?
3. Does the fracture grow into gas or water-bearing zone?
4. What is the optimum number of fracture treatment stages, and the best treatment size to cover thick pay zones?
5. Is the final fracture conductivity sufficient for target production? What is the optimum proppant?

These are a few of the many questions that engineers face in designing fracturing stimulation treatments.

1.3 – Well development

Well development is an integral part of the hydraulic fracturing process. Well development is broadly divided into: the drilling stage and the completions stage. For a successful fracturing operation it is important that drilling equipment are properly maintained and that their rated capacity is not exceeded. A drilling rig is the most visible part of the drilling operation, however what is important is the underground activity (King et al, 2012). In Fig 1.8, a drilling rig schematic is shown, with its visible equipment. As reported by King et al (2012), the main considerations in selection of drilling rigs are:

1. Noise, which can be minimized by using electric rigs;
2. Dust: If air drilling is used, control of air and cuttings is required
3. Appearance and time on location (usually 2 to 5 weeks): Most rigs for unconventional well drillings are from 50 ft to over 100 ft tall, which is visually undesirable and take more time to set up. Lower profile rigs are preferred on shallower wells but the trade-off is that larger rigs are faster in operation.
4. Water and mud storage: requiring determination of size of pits or steel tanks. Also, storage considerations for chemicals that would be mixed with the mud.
5. Pressure control equipment: The equipment has to undergo regular servicing and inspection.
Completions involve the final stages of the well development process, which include casing and cementing design.

1.3.1 Rotary Drilling

Rotary drilling primary elements

The rotary drilling process for a vertical or directional hole (Fig 1.9) involve the following elements:

1. Application of a force downward on a drill bit (see picture in Fig 1.10)
2. Rotation of the drill bit
3. Circulation of fluid, known as drilling fluid (liquid, gas or gasified liquid), from the surface through the tubular (drill string), and back to the surface through the annular space, which is the area between drill string and borehole wall or casing (see Fig 1.11) (Azzar and Samuel, 2007).

Rotary Drilling Systems

According to Azzar and Samuel (2007), drilling for oil and natural gas requires two major components: manpower and hardware systems. The hardware systems that make up a drilling rig are:

1. A power generation system
2. A hoisting system
3. A drilling fluid and circulation system
4. A rotary system
5. Well blowout control systems
6. A drilling data acquisition system
In this section, we would look at the functions of these systems and their working components. A section of a drill rig is shown in Fig 1.12.

**Hoisting system**

The core function of the hoisting system is to hoist the drill and casing strings during drilling and casing operations (Azzar and Samuel, 2007). The hoisting system is supported on a derrick or mast, which is the most visible part of a drilling rig, standing around 140 ft above the drilling floor. The derrick has a set of sheaves at the top over which steel rope can pass (Devereux, 2012). The main components of the hoisting system are: the drawworks (drum and brake), the crown block, the travelling block, the hook, drilling (wire) line and elevator as shown in the schematic Fig 1.13.

**Drilling fluid and circulation system**

The function of the fluid circulating system in rotary drilling is to ensure the movement of drilling fluid from the surface to the hole bottom and back to the surface. The major components of this system include: mud pumps/air compressors, high-pressure surface connections, drill string, drill bit, return annulus, mud pits and mud treatment equipment (Azzar and Samuel, 2007). A schematic fluid circulation system is shown in Fig 1.14.

**Rotary system**

This system’s primary function is to achieve rotation of the drill bit. It is comprised of the following: drill pipe, drill collar, rotary table, swivel, kelly bushing and drive, and kelly. In modern rigs, the rotary table is replaced with a top drive motor to induce drill bit rotation, especially in offshore drilling (see Fig 1.15 and Fig 1.16). The swivel supports the drill stem, enables rotation to take place and conveys drilling fluid to the drill string. The kelly is the first part of the drill stem beneath the
swivel, it allows drilling ahead at a total depth equal to its length before a new section of drill pipe is required to be added (Azzar and Samuel, 2007).

**Well blowout control system**

During drilling, the formation fluid can begin to flow into the wellbore, this is termed a kick. If this continues, a blowout can occur which poses severe danger to the fracturing operation, drilling crew and equipment. The well blowout control system’s requirements are to safely permit:

1. Shutting in the well at the surface.
2. Controlling the removal of formation fluids from the wellbore
3. Pumping high density mud into the hole
4. Tripping the drill pipe into or out of the hole

The basic components of the blowout preventer (BOP) stack are: annular preventer, ram preventers, spools, internal preventers, casing head, flow and choke lines and fittings, kill lines and connections, mud and gas handling facilities and accumulators (Azzar and Samuel, 2007). A schematic arrangement is shown in Fig 1.17 and a pictorial arrangement in Fig 1.18. Typically, a BOP stack would have at least one annular preventer and two ram preventers. Below the rams are pipes that extend to the side, called side outlets which allow flow out or into the annulus during well killing operations. One section of the side outlets connects to the standpipe manifold to direct flow to the annulus, it is called the kill line. The opposite side is called the choke line, it controls the flow in and out of the manifold. The moment a driller detects that a kick is in progress, one of the BOP stack preventer units will be closed to seal the well annulus (Devereux, 2012).
Blowout prevention equipment is crucial to rig selection. The BOP stack and system must have a pressure rating equal to or greater than the bursting pressure of casing string and wellhead (Azzar and Samuel, 2007). A BOP in position at an offshore facility is shown in Fig 1.19.

**Drilling data and acquisition system**

This system consists of devices to monitor, analyze, display, record, and retrieve information about drilling operations. The parameters of interest include: drilling rate, hook load, hole depth, pump pressure, flow rate, torque, rotary speed, mud density, temperature, salinity and flow properties, mud tank level, pump strokes, weight on drill bit, hoisting speed (Azzar and Samuel 2007).

The monitoring equipment are used to detect drilling problems such as lost circulation and well kicks. Drilling rate charts show points of drilling breaks which are useful in giving an idea of changes in rock lithology and formation pressures. A rapid increase in hook load may indicate that a lost circulation zone has been reached. Excessive torque readings may indicate a high concentration of drilled cuttings in the annulus or bit failure. A drastic increase in pit level may indicate the intrusion of formation fluids into the wellbore, hence indicating a kick and the danger of blowout occurring. Rotary speed, flow rate and mud properties have to be maintained to achieve optimum drilling conditions (Azzar and Samuel, 2007).

1.3.2 – Horizontal Drilling

Horizontal drilling simply means directing the drill bit to follow a horizontal path, oriented at approximately 90° from the vertical, through the reservoir rock (Azzar and Samuel, 2007). Over the years, hydraulic fracturing has been performed on vertical, deviated and horizontal wells. However the coupling of horizontal wells and hydraulic fracturing have been proven to improve well performance in oil and gas reservoirs (Britt et al, 2010). This is due to the fact that it enhances the
recovery of hydrocarbons and reduces the number of vertical wells to develop fields of interest. Horizontal wells have found application in the Barnett shale, Marcellus shale and other shale plays were fracturing operations have been conducted for several years.

To drill horizontally it is required to deviate the wellbore. Several methods exist for deviating the wellbore. They involve developing a side force at the bit, with a magnitude and direction sufficient to guide the bit to the pre-designed path (Devereux, 2012). These techniques include: jetting, whipstock, steerable motors, rotary drilling assemblies and rotary steerables. The process of deviating the wellbore is known as “kicking off” the well.

**Jetting**

This is the fastest and cheapest way to kick off the well. It involves the use of tricone drilling bits, which have nozzles between the three drilling cones. There is one large nozzle and two smaller nozzles. The Drilling fluid flows out of the larger nozzle with greater force than the others, hence a pocket would be washed into the rock in that direction (see Fig 1.20). By aligning the bit in the desired direction and increasing pump rate without rotating the bit, the well is deviated (Devereux, 2012). From the description, it can be seen that this technique would be more effective in unconsolidated formations.

**Whipstock**

When the kick off point is reached during drilling, the drillstring and bit is removed from the hole and a wedge, called a whipstock is placed into the hole. The drillstring is re-inserted into the hole. Forced against the side of the whipstock, it begins to deviate as drilling continues (see Fig 1.21). The drill string will bend to allow the bottomhole assembly (BHA) to go around the curved hole (Devereux, 2012).
**Steerable motors**

This is a downhole motor, which has an adjustable bend in its lower portion (see Fig 1.22). Thus, the entire drillstring can be rotated to the desired direction. Steerable motors are commonly used to initially kick off the well from its vertical path, but after the deviation angle exceeds 60°, it becomes difficult to make the assembly slide i.e. drill without rotating the drill string. Steerable motors that drill while still rotating the drill string exist, but are very costly (Devereux, 2012).

**1.3.3 – Completions – Casing and Cement design**

According to Azzar and Samuel (2007), the completion process begins when the drill bit first enters the pay zone. This is a very important part of the drilling process as materials such as drilling mud which may be adequate in other intervals may not be acceptable in the pay zone. In the initial completion design, the selection of the pay zone is the first step. It is based on several engineering considerations, which include:

1. Prospect development economies
2. Porosity and permeability requirements
3. Hydrocarbon type and saturation requirements
4. Recoverable hydrocarbon volumes
5. Pressure support
6. Reservoir stability
7. Availability of technology for cost-effective production of reserves
8. Ability to plug and abandon reservoir
9. Environmental factors and other risks
After considering the above factors, the drilling engineer decides on the appropriate completion type. Completion types are broadly classified into: open hole completions and closed hole completions.

In the open hole completions, drilling is carried out from the surface and terminated at the top of the pay zone then running and cementing the casing. Thereafter, the pay zone is drilled with non-damaging drilling fluid and mud. In this completion type, the formation has contact with the wellbore thus allowing production or injection along every section of the interval in contact (Azzar and Samuel, 2007).

For the closed hole completions, a casing string is first run to prevent borehole collapse and to isolate the productive formation. The size of the casing string is optimized along the drilling depth (see Fig 1.23) (Azzar and Samuel, 2007), In table 1.1, the completion types generally used are shown. Also shown are estimates of reservoir variables corresponding to the appropriate completion type.

**Casing design**

There are several types of casings, depending on the required function. In deep wells, as many as 6 different casings can be used to perform specific functions at different stages of drilling and completing the well (Devereux, 2012).

**Conductor pipe**

This is generally the first casing that is run in the well. It may be driven into the ground, using a pile driver or cemented inside an already drilled hole (see fig 1.24). According to Devereux (2012), it is used primarily to achieve the following:
1. As a closed circulation system, to allow drilling fluid return back to the surface as drilling progresses. This is useful so that mud returned can be treated, drilling cuttings removed and the mud re-used.

2. Prevents unconsolidated surface formation from being eroded away by the drilling fluid.

3. Sometimes used to support the weight of the wellhead and BOPs.

**Surface casing**

This is run through the conductor pipe and is set deep enough for the formation at the shoe to withstand pressure from a kicking formation several depths below (Devereux, 2012). It is cemented in place over the entire length of string. It has the following purposes:

1. Allows a BOP to be connected so that the well can be drilled deeper

2. Protect freshwater sources from contamination by the drilling fluids

3. Preventing loose or weak formation from falling into the wellbore

As put by Azar and Samuel (2007) “From a safety standpoint it represents the second line of defense, sealing the well and handling any high pressure flow”

**Intermediate casings**

These connect the surface casing to the production casing. They are used primarily to increase the pressure integrity of the well as it is deepened and to protect any directional work done. They are usually cemented in place, before higher mud weights are used. Intermediate casings are sometimes referred to as liners, when they are not hung from the surface but from some down hole point (Azar and Samuel, 2007).
**Production casing**

These are the final casing run in the well. In essence, they are long-term pressure vessels because they contain the tubing that serve as passageways for the hydrocarbon flow from the reservoir to the surface. If the tubing leaks, the production casing must be able to withstand the resulting pressure (Devereux, 2012).

The main design considerations for a casing string include: tension, burst pressure, collapse, driving forces, temperature, combined axial and internal forces, corrosion and connections (Devereux, 2012).

**Cementing**

Cementing is the final aspect of well completions. It is a generally rushed operation because of the haste to start producing the well. This sometimes leads to spending time and money trying to correct errors that initial care would have avoided (Azar and Samuel, 2007). Cement outside the casing is designed to meet various needs, which include:

1. Supporting the weight of the casing.
2. Preventing fluids from moving upwards inside the cement.
3. Preventing fluids from migrating between the cement/formation and casing/cement interfaces.
4. Serves as corrosion protection for the casing.
5. Protects the casing against movement of formation.
6. Allows for the perforation of the production casing, without the inner cement breaking-off due to the shock wave.
Most cements used in the oil and gas industry are a type of Portland cement. Portland cement has the four main constituents: tricalcium silicate \((\text{C}_3\text{Si})\), dicalcium silicate \((\text{C}_2\text{Si})\), tetracalcium aluminoferrite \((\text{C}_4\text{AlF})\) and tricalcium aluminate \((\text{C}_3\text{Al})\). Even when made from the same components, not all cements will react in the same way when mixed with water due to dissimilarities in cement grind, additives, water impurities and the manufacturing process (Azar and Samuel, 2007). The American Petroleum Institute (API) has established standard specifications for oil well cement. This designates 8 classes of cement, classified according to their behavior in deeper, high temperature down hole conditions. These classes are shown in table 1.2. The API class G cement has been found to be the most useful when its properties are modified during mixing (Devereux, 2012). In carrying out cement design, the following factors are considered: density, thickening time, compressive strength, temperature rating, rheology, chemical additives.
CHAPTER 2 – FORMATION EVALUATION

A formation consists of rock layers (strata) that have similar properties. A formation that contains recoverable hydrocarbons is called a reservoir. The region of the reservoir that is accessible to the well bore or fracture is usually called the payzone. Formation evaluation is important, especially in low permeability reservoirs because of the presence of alternating layers with various properties. It is necessary to define these properties, which include: thickness, fluid saturation, porosity, Young’s Modulus, in-situ stress, permeability, formation conductivity etc (Holditch et al, 1987). This is done by carrying out specialized tests and techniques that would be described in this chapter.

2.1 Formation Testing

2.1.1 Formation integrity Tests (FIT)

The formation integrity test is carried out to confirm the strength of formation and well casing shoe by increasing the bottom hole pressure to a design pressure. There is a lot of confusion in industry nomenclature, as formation integrity tests (FITs) are sometimes called Leak off tests (LOTs). The LOTs, also known as pressure integrity tests (PITs) are used to determine the fracture gradient of a formation (from stress estimates), as described in chapter three. However, FITs are conducted to show that the formation below the casing shoe will not fail while drilling subsequent sections with a higher bottom hole pressure. Simply put, the FIT is a pressure test applied to the formation directly below a casing shoe. It is generally conducted soon after drilling resumes after an intermediate casing string has been set. The purpose of the test is to determine the maximum pressures that may be safely applied without the risk of formation breakdown. The results of the test are used to design the mud program for the subsequent hole section and to set safe limits on casing shut-in or choke pressures for well-control purposes Schlumberger (2012).
Another difference between PITs and FITs is that stress estimates are not obtained with data from formation integrity tests (FIT) since fracture initiation does not actually occur. In the FIT, pressure is applied to a pre-defined value and no leak off occurs. The FIT indicates that the maximum well bore pressure did not exceed the least principal stress or was not sufficient to initiate a fracture of the well bore wall in an open hole test (Zoback, 2012). In well planning and development, the FITs are normally conducted before LOTs.

A straightforward way of calculating the pressure required for a formation integrity test (prior to performing the test) is using the formula:

Pressure required for FIT (psi) = (Target FIT (ppg) – Current mud weight (ppg)) x 0.052 x TVD of shoe in ft  

\[ \text{Pressure required for FIT (psi)} = (\text{Target FIT (ppg)} - \text{Current mud weight (ppg)}) \times 0.052 \times \text{TVD of shoe in ft} \]  

(2.1)

Where, TVD = True Vertical Depth; and the Target FIT (ppg) is the equivalent mud weight of the required FIT pressure.

It is worthy to note that no standard methodology exists in the industry for conducting FITs or LOTs.

In the next section, we would outline the field procedure of the formation integrity test, done by . This would also, cover the build-up section of the test which is the formation integrity test.

2.1.2 Field Procedure for Formation Integrity Tests

Postler(1997) writes extensively on field procedures for LOTs. Similarities exist between the way LOTs and FITs are conducted, hence some parts of this section would make reference Postler’s paper.
Reference Guidelines before the test (Postler, 1997)

A test graph is prepared before testing. The horizontal axis is labeled in ¼ bbl increments and the vertical axis in 100-psi increments. Then guidelines are drawn on the graph for reference during the test and to aid in interpretation. These guidelines are shown in fig. 2.1 (the fig. will be re-drawn to illustrate the FIT).

a. Predicted FIT Pressure: shown in the figure as a horizontal line. This value is based on data from offset wells and the local overburden or pore pressure gradients. This line acts as a guide during the test; A plot beneath this line is most likely not leak-off and pumping should continue.

b. Minimum Leak-Off Pressure: This horizontal line is equal to the predicted FIT pressure equivalent mud weight (EMW) given as “Target FIT* in eqn (2.1)” minus 1/2ppg. The ½ ppg accounts for inaccuracies in the predicted FIT pressure; pressure, volume or mud weight measurements; and mud gelation effects.

c. Maximum allowable Pressure: A horizontal line that indicates an upper limit based on equipment limitation or lost circulation experience.

Test Procedure

Department of Infrastructure, Energy and Resources, Tasmania (2008) present a description of the FIT field procedure. The method described below is termed the “hesitation method” of conducting formation integrity tests. It involves pumping and waiting for the pressure to stabilize before repeating the procedure until the maximum test procedure is achieved. During the test, it is ensured that the maximum pressure does not exceed any of the following:

1. Actual Leak-off pressure.
2. The pressure specified in the drilling program (typically 80% of casing burst pressure)

3. The wellhead test pressure

4. The blow-out preventer, BOP test pressure

5. A maximum pressure gradient of 0.8 psi/ft at the casing shoe (i.e. Required FIT Pressure/TVD of casing shoe).

A typical schematic diagram of equipment for the test is shown in Fig. 2.2.

The FIT procedure is as follows:

1. The formation of interest is drilled to approximately 10 ft

2. The drill string is used to pull the bit back in casing shoe.

3. It is then ensured the hole is filled and the annular BOP closed around the drill pipe.

4. Rig up the pump to the drill pipe. A pressure gauge of appropriate range (typically 0 to 1500 psi) is mounted at the top of the pump unit manifold.

5. Mud is pumped slowly until pressures begin to increase. Volume pumped will start from this point.

6. 0.125 to 0.25 bbl of drilling fluid is pumped, then waiting is done for 2 minutes or more depending on how much time is required for the pressure to stabilize.

7. The volume pumped is recorded, and the bleed back stabilized pressure.

8. Steps 6 and 7 are repeated and a plot of pressures versus cumulative mud volume is done.

9. The procedure is continued until either the final stabilized pressure deviates from the predicted FIT pressure or the required maximum pressure is reached. The stabilized pressure should be kept below the FIT pressure.

10. The well is kept closed in to be sure that a constant (stabilized) pressure has been attained.

11. The pressure is slowly released and volume recovered in tank is recorded.
2.2 Permeability, Fracture Conductivity and Fracture Length

The main aim of hydraulic fracturing is to initiate and sustain a stable fracture with high quality conductivity to maximize well productivity and recovery. There are three core design parameters that are germane to successful hydraulic fracturing treatment: permeability, fracture half-length and fracture conductivity. The relationship between these variables is given by:

\[ C_r = \frac{k_f w}{k X_f} \]  \hspace{1cm} (2.2)

Where \( C_r \) is the dimensionless fracture conductivity, \( k \) is the formation permeability, \( k_f \) is the fracture permeability, \( w \) is the fracture width and \( X_f \) is the fracture half-length. It is shown in Fig 2.3. Equation 2.2 describes the relationship between the fractures ability to transport fluids to the wellbore and the reservoir’s ability to flow fluids to the fracture (Jones and Britt, 2009). This sums up the essence of hydraulic fracturing. The fracture width, \( w \) is calculated from the fracture half-length and is given in detail in chapter 3.

Permeability is of critical importance in determining wells applicable for hydraulic fracturing. Since the main reason fracturing is done, is to extract deposits of natural gas or crude oil that would not flow naturally to the wellbore. The permeability of the formation also affects the formation breakdown pressure in hydraulically fractured wells. It is based on this effect that it can be determined from the pressure buildup data of pressure tests. Experimental evidence supports the fact that permeable rock has a lower breakdown pressure than impermeable rock under similar conditions. Also, asides from showing a lower leak-off (breakdown) pressure, a Pressure Integrity test (PIT) in a highly permeable formation shows a non-linear pressure build-up due to fluid losses (Postler et al, 1997).
2.2.1 Obtaining the design parameters from Pressure build-up test: An Introduction

The three conventional test configurations for the pressure buildup test are shown in Fig 2.4. The main feature of this test is that only a limited portion of the well is open to flow. It is sometimes called the limited entry model test. The dimension, hw in the figure is the perforated (flow) interval length.

Lee and Holditch (1979) carried out a theoretical investigation of pressure transient testing for formation evaluation in low permeability gas reservoirs. Most current methods of analysis are based on this investigation. In summary, Lee and Holditch reviewed the pseudo-radial method of Russell and Truitt (1964) and the linear flow method of Millheim and Cichowicz (1968), then propose a modification to the method of Millheim and Cichowicz. In this section, we would review the work done by Lee and Holditch investigation before describing another method suggested by Barnum et al, 1990.

The Lee and Hoolditch method doesn’t consider the effects of partial perforation (limited entry), but examines different fluid flow regimes for unbounded and bounded reservoirs. The Barnum model considers the partial perforation model but is done for a single partial perforation configuration. The Barnum proposition is also only applicable when the first straight line on the plot is significant (high wellbore storage) which is mostly in low permeability reservoirs.

2.2.2 Parameter Determination from Pressure tests by the method of Lee and Holditch (1979)

This investigation was done to obtain permeability, half-length and fracture conductivity in low permeability hydraulically fractured reservoirs. Data for this paper was based on pressure testing of a South Texas gas well. Lee and Holditch considered pseudo-radial, linear flow, modified Millheim-Cichowicz method and Simulator history matching.
Pseudo-radial Flow

This was pioneered by Russell and Truitt (1964). Pseudo-radial flow is defined by Lee and Holditch (1979) as one in which sufficient time occurs during buildup or drawdown such that the bottomhole pressures varies linearly with flow time for drawdown tests or \((t_h + \Delta t)/\Delta t\) in a semi-log plot (Horner plot) for buildup tests. In an unbounded reservoir (infinitely acting) reservoir, the analysis depends on the skin factor, given by Van Everdingen and Hurst to be:

\[ S = 1.151 \left[ \frac{(P_1 - P_{wf})}{m} - \log \left( \frac{k}{\phi \mu c_t r_w^2} \right) + 3.23 \right] \]  
(2.3)

Where, \( r_w \) is the wellbore radius; \( \phi \) is the porosity; \( \mu \) is the viscosity; \( C_t \) is the total fluid compressibility (psi\(^{-1}\)), measured at initial pressure; \( P_{wf} \) is the flowing well bore pressure and the value of \( P_1 \) is obtained from the straight line portion of the pressure buildup curve 1 hour after shutting in, \( k \) is the permeability.

Fracture half-length, \( X_f \) (ft) for infinitely conductive vertical fractures is given by:

\[ X_f = 2r_w e^{-s} \]  
(2.4)

Taking the log of both equations and equating to eliminate \( s \), we obtain

\[ \log X_f = \frac{1}{2} \left[ \log \left( \frac{k}{\phi \mu c r_w^2} \right) + \frac{(P_{wf} - P_1)}{m} - 2.63 \right] \]  
(2.5)

Thus, from the pressure buildup test, a Horner plot can be made and the slope, \( m \) determined (see Fig 2.5). The formation permeability can thereafter be obtained from the following:

\[ K = 162.6qB\mu/mh \]  
(2.6)
q is the gas flow rate (Mscf i.e. $10^3$ standard cubic ft), B is the gas formation volume factor evaluated at the initial pressure, (bbl/ Mscf) and the half-length can further be determined from equation 2.4.

Lee and Holditch outlined several practical problems with the Pseudo-radial flow method. The most important of which was that this method is not very useful in low permeability reservoirs because the time required to obtain the straight line where the slope is related to formation permeability can be too long, taking months or years. Other problems are that it assumes infinite fracture conductivity which isn’t always reasonable and finally, It may be difficult to obtain the proper slope because of boundary effects that become appreciable as a result of delay in pressure transient.

For moderate to high permeability reservoirs, the pseudo radial method is extremely useful. Pratt (1961) showed that for such reservoirs, pseudo radial flow can be used to model radial flow behavior and vice versa (Jones and Britt, 2009)

Linear Flow

Consideration of linear flow was started by Millheim and Cinchowicz, who showed that when the principal flow into a fracture is linear i.e. at the start of the test (earliest times), the pressure-time characteristics for a pressure buildup test is given by:

$$Pi - Pws = m' \left(\sqrt{t_p + \Delta t} - \sqrt{\Delta t}\right)$$

(2.7)

When, $t_p \gg \Delta t$,

$$Pws - Pwf \cong m'\sqrt{\Delta t}$$

(2.8)

Where $Pi$ is the initial reservoir pressure, psi; $Pwf$ is the flowing bottomhole pressure, psi and $Pws$ is the shut-in bottomhole pressure in psi, $t_p$ is producing time in hr.
A plot of bottomhole pressure versus square root of time would result in a straight line with slope, $m'$ related to the fracture half-length and formation permeability as follows:

$$X_f \sqrt{k} = \frac{q_B}{h_m} \sqrt{\left(\frac{\mu}{\phi C_t}\right)^2}$$  \hspace{1cm} (2.9)

Figure 2.6 shows an example plot of this method, with data from a pressure buildup test.

Limiting assumptions of this method include:

1. An independent estimate of formation permeability must be made in order to obtain $X_f$. This value may be obtained from prior pressure test data from offset wells.

2. An impractically high value of fracture conductivity is assumed, so that fluid flow per unit area of the fracture at the well bore is the same as that at the tip (uniform flux).

3. The linear flow mechanism can only suffice for earliest-time data, without distortion caused by wellbore storage, which is not always the case.

Modified Millheim Cinchowicz method

Lee and Holditch propose a modification of the Millheim Cichowicz (M-C) method for finite conductivity vertical fractures. For drawdown tests, this is done by plotting the dimensionless pressure versus the square root of dimensionless time, as shown in Fig. 2.7. The data used for the figure was published by Cinco et al (1978). The dimensionless pressure, $P_D$ is given by:

$$P_D = \frac{kh(P_i-P_{wf})}{141.2q_B\mu}$$  \hspace{1cm} (2.10)

and dimensionless time, $t_0$ is given by:

$$t_0 = \frac{0.00024 \; kt_p}{\phi \mu C_t x_f^2}$$  \hspace{1cm} (2.11)
From the fig. 2.7, it can be observed that at low values of Cr, the plot of $P_D$ vs $\sqrt{t_D}$ is non-linear at the earliest times of pressure buildup. Larger values of Cr however, have more linear plots at their earliest times. Generally, at $\sqrt{t_0} < 0.15$, transient flow affects pressure-time behavior, at $0.15 < \sqrt{t_0} < 0.34$ true linear portion of the plots are seen and at $\sqrt{t_0} > 0.34$, pseudo radial flow is established (Lee and Holditch, 1979).

For both build-up and drawdown tests, the modified M-C method is outlined as follows:

1. Using an independent estimate of $k$, a plot of $P_D$ vs $\sqrt{t}$ is done (see fig. 2.8).
2. The linear portion of that plot (fig. 2.7 for drawdown and fig 2.8 for buildup) is extrapolated as a straight line to $\sqrt{t_D} = 0$ (see Fig. 2.9) and the value of the intercept is recorded.
3. The slope and intercept values of buildu p/drawdown data is then compared with standard charts containing Cr curves, in order to obtain an estimate of the Cr.
4. For a selected value of $P_D$, the matching values of $\sqrt{t}$ and $\sqrt{t_D}$ can be obtained and substituted in the following equation to obtain the half-length,

$$X_f = \left( \frac{0.0002637 \ K}{\phi \mu C_t} \right)^{1/2} \left[ \frac{t}{t_D} \right]^{1/2}$$

...............(2.12)

The modified M-C method proposed by Lee and Holditch still suffers the disadvantage of requiring a first estimate of the permeability, $k$ to obtain the fracture length and conductivity. However, it provides better estimates of fracture half-length and conductivity from early-time pressure buildup data.
2.2.3 Parameter Determination from Pressure Buildup tests by the method of Barnum et al (1990)

Barnum et al, 1990 carried out work on analysis of pressure buildup tests laying emphasis on the configuration type, were the perforation interval was in the middle of the formation (see Fig 2.4). It was based on plots of bottomhole pressure against the log of time. This results in a three-region curve as shown in case 3 of fig 2.10. The first region is a straight line with a slope inversely proportional to the permeability-thickness of the perforated interval. The second region is a concave upward curve representing the transition between the first and third time region. The third/final region is a typical straight line chart. In the various cases of figure 2.10, p* and p_i can be seen. P* is the extrapolation of the first straight line to infinite shut-in time. The dimensionless pressure group, (p* - p_i)/m can be correlated with the vertical permeability and would be shown later. Where, m is the slope of the first straight line (Barnum et al, 1990). In the partial perforation model, there is a near-wellbore restriction to flow due to wellbore damage. Wellbore damage is caused by the infiltration of mud, cement, filtrate etc which alters the pressure buildup curve at an early shut-in time, as shown in fig 2.11. The result is an extra drop in the pressure distribution at the wellbore, in what is referred to as the “skin effect” (Howard and Fast, 1970). Saidowski (1979) showed that the total or apparent skin factor, St based on the Horner analysis of the final straight line, could be represented as follows:

\[ S_t = \frac{h}{h_w}S + S_p \]  

\[ \text{..............................(2.13)} \]

Where, S= actual skin factor due to apparent damage caused by wellbore restriction,  

\[ S_p = \text{pseudo skin factor resulting from partial perforation}, \]

\[ h = \text{total formation thickness}, \]

\[ h_w = \text{perforated interval length}. \]
The methods of calculating actual skin friction from empirical relations, exist in literature. For instance, Van Everdingen and Hurst give an equation for $S$ as given already in equation 2.3:

$$S = 1.151 \left[ \frac{(p_1 - p_{wf})}{m} - \log \left( \frac{k}{\microtext{c}} r_w^2 \right) + 3.23 \right]$$

Where, $r_w$ is the wellbore radius, $p_{wf}$ is the flowing well bore pressure, measured just before shutting in, and the value of $p_1$ is obtained from the straight line portion of the pressure buildup curve 1 hour after shutting in. If the buildup curve is not straight after one hour, the straight line must be extrapolated backwards, as shown in Fig 2.12; $k$ is an independent estimate of permeability (Howard and Fast, 1970).

The actual skin friction, $S$ is constant and can range from +1 to -3. Other methods of obtaining $S$ based on the dimensionless real gas potential obtained from pressure drawdown curves are shown in Fig 2.13 (Vairogos and Rhoades, 1973). The actual skin friction is used to simulate wellbore damage (stimulation).

The pressure drop in the skin can be obtained from the following:

$$\Delta P_{\text{skin}} = m \times 0.97s$$

The efficiency of the completion can be obtained by comparing the actual productivity index, $J$ and the ideal (no skin). The ratio of these quantities is the flow efficiency, given by:

$$\text{Flow Efficiency} = \frac{J_{\text{actual}}}{J_{\text{ideal}}} = \frac{P_i - P_{wf} - \Delta P_{\text{skin}}}{P_i - P_{wf}}$$

The pseudo skin factor, $S_p$ is a function of the horizontal to vertical permeability ratio and can be estimated from the following equation:

$$S_p = (h/hw - 1) \left[ \ln(h/rw) \sqrt{(kh/kv)} \right] - 2$$
Authors like Streltsova-Adams and McKinley (1981) developed techniques to obtain the vertical permeability based on the start time of the second straight line region. Others like Bilhartz and Ramey (1977) suggested methods based on the end time of the first line and the beginning time of the second line. In 1986, Yeh and Reynolds developed a type curve fitting technique for vertical permeability determination. The 1990 method proposed by Barnum et al would be discussed here. It is a method proposed when the first straight line region exists for significant time periods. This case is obtained in formations with adequately low permeability (such as shale), such that the flow from the entire interval is significantly delayed. There are three pressure buildup patterns that exhibit a first straight line characteristic of the perforated interval, as seen in Fig 2.10. Under constant flow conditions: In Case 1, the buildup response would be only the first straight line, this occurs when the vertical permeability is very low or when the flow time is short. Case 2 occurs when the vertical permeability is higher, hence longer flow times. In Case 3, for much higher permeability and even longer (relative) flow times, the three regions will occur.

It is worthy to note that the permeability determination of Barnum et al, 1990 is based on the Hantush partial perforation model which has the following assumptions:

1. An infinite reservoir of constant thickness with impermeable upper and lower boundaries.
2. Single phase flow with constant fluid properties.
3. Homogenous rock properties, with constant horizontal and vertical permeabilities throughout the formation of interest.

The dimensionless pressure group, \((p^* - p_i)/m\) is correlated with the vertical permeability, flow time and thickness of the perforated interval, as given in fig 2.14 for centered completions of 10, 20, 40, 50, 67 and 80 percent (percentage of the total interval that is perforated). A plot of the dimensionless group versus dimensionless time, \(t_{DV}\) given as follows:
\[ t_{DV} = \frac{0.0002637 \, K_p \, t_p}{\varnothing \, \mu \, h_w^2 \, C_t} \] ........................(2.17)

where \( t_p \) is the producing time in hours, \( C_t \) is the total compressibility, \( \psi_i^\varnothing \) is the viscosity in cp. \( \varnothing \) is the porosity. This is very similar to the dimensionless time given in equation 2.11, the difference is the replacement of fracture half-length, \( X_f \) with perforation interval length, \( h_w \).

**Analysis Procedure**

1. Construct a Horner plot of the pressure buildup data (as shown in fig. 2.11)
2. Compare the resulting plot with the buildup patterns of figure 2.11 in order to locate straight line regions.
3. Determine if a particular straight line is the first or final region by applying the following two checks:
   - Compare the total skin factor, \( S_t \) based on this line (is calculated from eqn 2.3) with the pseudo skin factor, \( S_p \) estimated from equation 2.4. If \( S_t \leq S_p \) (i.e. negative \( S \)), then the line is most likely the first straight line region. If \( S_t \geq S_p \) (i.e. positive \( S \)), the line is probably the final straight line region.
   - Compare \( p^* \) from this line with \( p_i \). If \( p^* > p_i \), then the first straight line region is most likely present, but if \( p^* = p_i \), the line is probably the final straight line region.
4. After the checks in step 3, if a straight line region is recognized, and a portion of the transition region is present then perform an additional check on the validity of this selection with the nomogram in Fig. 2.15. If the end of the line is not apparent, the latest time \((t_p + \Delta t)/\Delta t\), should be \( \leq \) the end of the straight line indicated by the end of the nomogram.
5. Calculate \((p^* - p_i)/m\) for this first straight line using fig 2.14 with the corresponding completion percentage curve, to estimate the dimensionless time, \(t_{DV}\). The vertical permeability can then be obtained from equation 2.17.

When the first straight line does not exist, other techniques by the previously mentioned authors: BilHartz and Ramey; Streltsova-Adams and McKinley should be used. A method of permeability determination based on the consideration of time for different flow regimes (early radial, hemispherical spherical, infinitely acting radial), proposed by Ehlig-Economides et al, 2006 is also recommended.

### 2.2.4 Permeability from Productivity Index test

The productivity index test, is basically the flowback test. In this test, the pressure after shut-in is released in a controlled manner and monitored. The flowback test is carried out after the pressure buildup test. Details of the flowback test are in chapter 3. The productivity index permeability is obtained from the following equation:

\[
K_{PI} = \left[ \frac{q\mu B}{I_{n} \left( \frac{r_e}{r_w} \right)} \right] / 0.007073 h (P_{ws} - P_{wf}) \]  \[
..........................(2.18)
\]

Where, \(r_w\) is the radius of the wellbore(ft), \(r_e\) is the external radius(ft), \(h\) is the formation thickness, \(P_{ws}\) (psi) is the static reservoir pressure obtained from the pressure buildup data. It is given by the following, for infinite homogeneous reservoirs:

\[
P_{ws} = P_i - 162.6 \frac{q\mu B}{kh} \log \frac{t + \Delta t}{\Delta t} \]  \[
..........................(2.19)
\]
2.3 Well Condition Ratio

The well condition ratio is an important parameter in determining the applicability of wells for fracturing. It is the ratio of the permeability from a productivity index test to the buildup test. If a reduction in permeability exists near the well, the permeability from a productivity index test will be lower than that measured from a pressure buildup test. Thus if a well condition ratio, \( CR = \frac{K_{pi}}{K_{bu}} < 1 \) then there is a permeability reduction but if \( >1 \) then there is an increase in effective permeability. An increase in effective permeability could result from an earlier fracture treatment or an acid stimulation (Howard and Fast, 1970).

2.4 Applicability of Wells for Fracturing

The choice of wells as candidates for fracturing is determined from considering various factors. This section first considers the effect of well condition ratio; buildup data interpretation and formation fluid carrying capacity.

2.4.1 From Buildup and Well Condition Ratio

Low permeability Effect on fracturing response

A high reservoir pressure with no significant near bore permeability reduction is no guarantee that a well would produce at commercially acceptable rates. This is because the well may still be too tight to produce at economical rates without fracturing stimulation. Data by Wilsey and Bearden (1953) show that if the slope of the pressure buildup curve is greater than about 50 psi/cycle/Bbl/day (i.e pressure vs production graph) producing rate, when plotted on a semi-log graph, and if considerable reservoir pressure exists, then that well would respond favorably to reservoir fracturing treatment (Howard and Fast, 1970) .
Determination of State of Pressure Depletion

The static reservoir pressure can be obtained from the pressure buildup data. If this pressure is low, then there is no need to carry out stimulation since most of the primary reserves have been already recovered from the formation. Fracture treatment on low pressure reservoirs would in a short period lead to pressure decline, thus making it not economically viable (Howard and Fast, 1970).

Possible Increase in productivity from fracturing using condition ratio

The possible increase in productivity of a well can be determined by comparing the well condition ratio obtained before and after stimulation using identical treatment. If a condition ratio is changed from 0.1 to 1.0 after treatment then a ten times increase in stabilized production can be expected from the well after fracturing treatment. A higher condition ratio means less reduction in nearbore permeability which improves well productivity. Condition ratios obtained using fracturing fluids like surfactants can at maximum improve the condition ratio to 1.0. In order to obtain a condition ratio > 1.0 then the rock has to be subjected to a physical change for instance by using acid treatment. The lower the natural formation permeability, the greater the condition ratio that could be achieved from treatment. Moderate permeability formations after any degree of stimulation could only have condition ratios ≤ 2.0. While low permeability formations can have condition ratios as high as 5.0 (Howard and Fast, 1970).

Effect of Formation Fluid-carrying Capacity

The formation fluid-carrying capacity (formation thickness x formation permeability) significantly affects formation response to different sizes of fracturing treatments. Fig 2.16 shows a formation’s response to treatment with two fractures of different fluid-carrying capacities (200md-ft and 5000md-ft). From these plots, the higher the formation capacity, the higher the capacity of
fractures (fracture permeability x fracture height) needed to ensure adequate fracturing treatment. Refer to Fig 4.25, to see a plot of the fracture capacity normalized to the formation capacity against the stabilized productivity ratio. The fracture penetration is represented as a percentage of the drainage radius (i.e. radius of fracture areal extent). As the ratio of fracture to formation capacity increases, deeper penetrating fractures would lead to an increase in stabilized well productivity (Howard and Fast, 1970).

2.4.2 General Criteria/Limitations on Well Selection for fracturing treatment

Proximity to Water and Gas Contacts

The impact of hydraulic fracturing on natural water bearing zones is a huge debate in the industry. There are many accounts of the deleterious impact of fracturing on drinking water, told by land owners and residents of lands adjacent to fracturing sites. Although there is little scientific publications corroborating or refuting these claims, companies prefer to reject a potential fracturing candidate entirely or reduce the size of treatment due to proximity of water contacts. Systems mitigating the effects of water zone penetration exist using relative permeability modifiers in the fracturing fluid or employing specialized proppant systems (dos Santos et al, 2009). However, the use of these techniques almost inevitably requires the production/use of large amounts of water during fracturing which can negate oil/gas production (Martin A.N et al, 2010). During oil production the proximity of a gas contact influences suitability of a well for fracturing treatment, as fractures could penetrate upward into a gas contact in the same way.

Containment within Payzone

It is important that fractures are designed considering the in-situ stress contrast, whether the overlying layers (outside pay zone) would be sufficient barriers to fracture propagation or not. This
is to ensure that the fracture doesn’t cross into water bearing strata (as enunciated in the first section) and also to make for economical fracture treatment. This is shown in fig 2.17. In essence, the stress gradient has to be considered when fracturing since the fracture direction would depend on the in-situ stress i.e. consideration of the overburden stress is important to know the extent of fracture propagation. See Fig. 2.18, in this diagram the effective stress gradient is assumed to vary linearly downwards. (Heydarabadi et al., 2010).

**Condition of Well Equipment**

Due to the significantly high pressures expected during fracturing, it is necessary that the well equipment should be able to adequately withstand such pressures. Well bore tubulars (i.e. casing and tubing), gas lift mandrels and valves, sliding side doors, subsurface safety valves and flow control devices. Packers have to be tested to ensure that fracturing pressure doesn’t cause blowout (see Fig 2.19). Hence, if the equipment do not meet the minimum requirements for the design hydraulic fracture, stimulation cannot proceed (Martin A.N et al, 2010).

**Skin factor considerations**

A high positive skin factor justifies fracturing treatment since it indicates that the formation permeability is higher than the near wellbore permeability. A negative skin factor however doesn’t eliminate the need for fracturing altogether. It means the formation permeability is less than permeability surrounding the wellbore, and could indicate the presence of natural fractures in the formation. If an acid treatment does not improve productivity, then hydraulic fracturing can be considered (Heydarabadi et al., 2010).
Production History of Offset wells

A well with significantly lower production rate than offset wells in a field would most probably benefit from fracturing treatment. Since its low production rate might be caused by reduction in effective permeability around the wellbore (Howard and Fast, 1970).

2.5 Core Analysis

Core analysis simply means obtaining actual samples of rock and testing to know the physical and chemical properties. It is imperative for a comprehensive formation evaluation. Coring analysis, provides the only direct method of measuring reservoir petrophysical properties. In spite of this, variation in data quality, sensitivity of results to different test methods, and the reluctance of companies to share expertise and experience have caused poor data quality and errors in interpretation of core analysis (McPhee, 2012). Best field and laboratory practices have to be followed to obtain high quality results from core analysis.

Because most formations consist of layered strata, it is important that core obtained be cut for different layers. In productive (pay) zones, the interest is normally in those properties that determine amount of oil and gas present, and reservoir production rates. Such properties include: permeability, porosity and water saturation. For the non-productive layers interest is more in the formation geomechanical properties and stress distribution in order to calculate fracture geometry. These parameters include: poisson’s ratio, Young’s modulus and fracture toughness. The method of core recovery chosen depends on the specific rock type. Core recovery types can be shown in the table 2.1. A full closure catcher used to obtain whole cores is shown in Fig. 2.20.

Coring Analysis techniques can be divided into three broad groups: 1. Qualitative, Visual Analysis; 2. Routine, Quantitative Analysis; 3. Special Core Analysis (Holditch et al, 1987).
2.5.1 Qualitative, Visual Analysis

This involves all the techniques for visual description of the core. It involves: core photography, scanning electron microscopy (SEM), X-ray diffraction, thin section analysis. Other core imaging techniques include: nuclear magnetic resonance (NMR), computerized tomography (CT), micro-CT, X-ray CT, acoustic and electrical resistivity.

Core photography

Core photographs are best taken under natural and ultraviolet (UV) light. Oil fluorescence is revealed under UV light and hence the location of hydrocarbons. Multiple-footage photographs as seen in Fig 2.21 are useful for the observation of changes in core bedding that indicates differences in depositional environment, permeability, etc. (Keelan, 1982).

Scanning Electron Microscopy (SEM)

This enables electron photographs to be taken of pore space and magnified up to 40,000 times. Samples are coated with an ultra-thin layer of electrically conductive materials and then bombarded with electrons, leading to a secondary electron emission that yields a visible image (see Fig. 2.22). The two most important uses of SEM are to recognize the clay type, and to observe microporosity in clay linings and carbonates (Keelan, 1982).

X-ray diffraction

This is a method widely used in the identification of minerals, based on their unique diffraction response to X-rays. It finds application in identifying clay minerals during coring analysis. However, some materials such as amorphous chert cannot be identified by X-ray diffraction techniques (Keelan, 1982).
NMR

This method has been in use as a petrophysical core analysis method since 1953. Its use has been extended from prediction of pore size and wettability to estimation of permeability, water saturation and residual oil saturation. It makes use of the radio frequency response of protons in a magnetic resonance field to determine spin-lattice relaxation time, $t_1$ and spin-spin relaxation time, $t_2$ (see Fig 2.23). These relaxation signals are linked to fluids within the pore network and correlated with standard pore-size measurements, such as mercury injection (Unalmiser and Funk, 1998). The results are processed further to obtain the aforementioned core parameters.

CT scans

These are useful in obtaining digital image of core samples, and also serve as saturation monitoring tools. With accurate calibration, CT axial slice and longitudinal scout images provide digital data that can be used to obtain density, fracture orientation, porosity, pore volume connectivity, and net-to gross ratios (Unalmiser and Funk, 1998).

Fig 2.24 to Fig 2.26 show CT scans of three different samples obtained from a single well. Figure 2.24 displays the CT scan image of a non-uniform sample, which is not visible from outside using the core photograph alone. The sample shown in Fig 2.25 has large vugs (cavities). The vugs can be seen on the surface (dark spots) and internally with the CT scan. The sample in fig 2.26 is uniform and an ideal candidate for core analysis studies. Both non-uniform and vuggy samples are not good for further core analysis studies (Al-Multhana, 2008).

2.5.2 Routine, Quantitative Analysis

These are done to obtain first-order estimates of porosity, permeability, fluid saturation and lithology. These variables are useful for determining oil and gas in place (OIP) measured in tcf (tons
per cubic ft). It is the value of oil/gas per volume of rock, as shown in the formula below (McPhee, 2012):

\[
\text{OIP} = \text{GRV} \left( \frac{N}{G} \right) \phi (1 - S_w)^{1/B}
\]

\[
\text{.........}(2.20)
\]

Where GRV is the gross rock volume and G is the gross factor in the net to gross ratio (N/G). B is the formation volume factor obtained from PVT experiments. N is the net, \( \phi \) is the porosity and \( S_w \) is the water saturation obtained from routine, quantitative analysis and logging.

Routine, quantitative analysis is normally done 24 to 48 hours after a core is cut, because results may immediately decide on whether a well would be completed or abandoned (Holditch, 1987).

**Permeability**

The standard method of obtaining permeability in routine core analysis is by allowing dry gas, usually nitrogen, helium or air to flow through the samples. It has the following advantages over using liquid permeability: reduced fluid-rock interaction, easier to execute, faster and less expensive. In liquid producing reservoirs however, the validity of the gas permeability method is being questioned (Unalmiser and Funk, 1998) Another shortcoming of using dry gas to obtain permeability is that it has to be corrected for the Klinkeberg effect, also known as gas slippage. This effect is due to variation in permeability measurements with the type of gas used and the mean existing pressures in the core when measurement was done. It is more evident in samples from low permeability formations (Keelan, 1972). Modern permeability testing include corrections for both the Klinkeberg effect and the Forcheimer inertial coefficient (Unalmiser and Funk, 1998).

Equations for obtaining linear and radial permeability measurements and details of equipment used are available in the American Petroleum Institute (API) Recommended Practice (RP) 40. However,
generally rock permeability in the laboratory is given by the following formula, based on Darcy’s law:

\[ K = \frac{245Q\mu L}{A\Delta P} \]  

\[ \text{.........(2.21)} \]

Where \( K \) is the absolute permeability (md), \( Q \) is the flow rate (cc/min), \( L \) is the sample length (inches), \( A \) is the cross-sectional area (cm\(^2\)), \( \mu \) is fluid viscosity (cp), and \( \Delta P \) is the differential pressure across the sample (psi).

Several conditions can affect permeability measurements, they include: drying time, confining pressure and core fluid/relative permeability effect (caused by the presence of more than one fluid in pore spaces). Table 2.2 shows the effect of confining pressure on permeability measurements of a well sample.

From the table, it is seen that the permeability values increased by about 70 to 80% when the confining pressure was less than 200 psig. Specifications for testing standards recommend that confining pressure should be greater than 200 psig (Al-Multhana et al, 2008). It is important to note though, that natural overburden pressures can be as high as 6000 psi and thus, reservoir permeability would invariably be different from those obtained from typical laboratory tests. Keelan (1972) reports that Shale cores, unconsolidated, fractured samples and low permeability (<0.1 md) formations show high sensitivity to overburden pressures. He further states that, “Permeability reduction increases with overburden and reduction values of as little as 7 to as great as 100 percent of initial values have been reported for overburden pressures up to 5000 psi”
Porosity

Porosity is the ratio of void volume to total (bulk) volume. It is obtained by measurement of either two of the three variables: pore volume (PV), bulk volume (BV) and grain volume (GV). Since,

Porosity, $\phi = \frac{PV}{BV}$ and $BV = PV + GV$

...........................(2.22)

It is important that standard calibration of temperature and barometric pressure is done when measuring grain density for GV determination. A dolomite sample (shown in Fig 2.27) had a grain density that reduced by about 0.005g/cc after calibration (Al Multhana et al., 2008). Porosity measurement like permeability is also sensitive to drying time as shown in fig 2.28. The type of porosity test to be carried out depends on the formation being sampled, for instance in vuggy formations special procedures are required.

Saturation

Measurement of residual fluid saturation was originally done by: 1. Using high powered vacuum distillation to recover oil and water; 2. Distillation extraction, which divides the extraction process into two parts. Firstly water is distilled, then oil is extracted using suitable solvents (Keelan, 1972). Currently, fluid tracer studies, displaced-miscible fluid analyses (reducing damage to clays) and improved geochemical techniques are used to obtain saturation (Unalmiser and Funk, 1998). The calculation of saturation from electrical properties is treated in section 2.5.3, under electrical properties.

Fluid saturations are normally reported as a percent of the pore volume, and the accuracy of measurements is largely determined by conditions during sample recovery.
2.5.3 Special Core Analysis

The special core analysis is divided into two stages. In the first stage, the measurement of permeability and porosity are repeated using other techniques and further coring analysis is done to obtain measurement of capillary pressure, relative permeability, electrical properties, and cation exchange capacity (CEC) (Holditch, 1987). A parameter of interest that influences most of the properties in the first phase is the wettability of the sample. It is a measure of the preferred inclination of a fluid, i.e. water or oil to spread on the rock surface (Unalmiser and Frank, 1998). It combines the interaction of the rock surface, fluid interfaces and pore shape (Morrow, 1991).

Category 2 of the special core analysis involves measurement of formation geomechanical properties like Poisson’s ratio, Young’s modulus, and fracture toughness (Holditch, 1987).

Capillary pressure

Capillary pressure is used to characterize the reservoir by indicating water saturation, size of pore channels and differentiating productive from non-productive intervals (Keelan, 1982). Laboratory techniques for determining capillary pressure include: porous plate, centrifugal testing, mercury injection and water vapor desorption (Unalmiser and Frank, 1998).

Electrical Properties

According to McPhee (2012), a fundamental set of equations was defined by Archie (1942), that gave the relationship between porosity ($\emptyset$), formation resistivity ($R_t$), formation water resistivity ($R_w$), core resistivity, $R_o$ and water saturation of reservoir rocks ($S_w$). The Archie Water Saturation Model, based on the electrical properties of the rock is given below:

$$F = \frac{R_o}{R_w} = \frac{1}{\emptyset^m}$$ ................................(2.23)
\[ I = \frac{R_t}{R_o} = \frac{1}{S_w^n} \] ..................(2.24)

Combining equations (2.23) and (2.24), give:

\[ S_w = \left[ \frac{1}{\frac{R_w}{R_t}} \right]^{(1/n)} \] ........................(2.25)

The porosity exponent, also called cementation factor, “m” and saturation exponent, “n” are obtained from formation factor, (F) and resistivity index (I) tests on the core.

**Young’s Modulus**

The Young’s modulus is obtained from coring analysis by conducting triaxial compression tests. However, logging techniques have been advanced to obtain the Young’s modulus from velocity measurements obtained during logging analysis. This would be outlined in section 2.6

**2.6 – Logging Analysis**

Logging operations is a very important part of formation evaluation. Extensive work has been done on improvement of logging tools and monitoring programs. Well logging can be performed at any stage of a well’s development: drilling, completions, production or abandonment. This section presents a brief overview of the typical logs. Holditch (1987), recommends the following precautions for openhole logs:

1. A low water-loss mud system should be used.
2. The hole should be drilled at a moderate rate of penetration to reduce the possibility of washouts occurring.
3. Calibration of the logging tools and adequate maintenance has to be done before logging operation.
Logs can be broadly grouped into: electrical logs, lithology logs and logging-while-drilling (LWD). It must be mentioned here that LWD is not necessarily a “group” of logging operations but a condition of logging. Thus, electrical or lithology logs can be LWD’s depending on the particular constraints surrounding each individual operation.

2.6.1 Electrical logs:

These include: sonic logging, resistivity logging, neutron porosity logging, density logging, image logging. A popular electrical log is the sonic log. Sonic logging involves the measurement of the travel time of an acoustic wave through the formation. It is used principally to calibrate seismic data and to obtain formation porosity (Glover, 1986). The integration of logging and core analysis in tight gas reservoir (TGR) characterization is of utmost importance, especially in defining porosity. Due to heterogeneity, formations may contain micro fractures, that can cause “secondary porosity” (Orlandi et al, 2011)

Asides porosity, sonic logs are also used to estimate rock geomechanical properties. A density log and a full wave form (shear and compressional waves, see Fig. 2.29) are recorded after running a sonic log. Holditch (1987), outlines the following equations that can be used with data from sonic logs to calculate the rock mechanical properties:

\[
\nu = \frac{0.5\left(\frac{\Delta t_s}{\Delta t_c}\right)^2 - 1}{\left(\frac{\Delta t_s}{\Delta t_c}\right)^2 - 1}
\]  \hspace{1cm} \text{.................(2.26)}

\[
G = 1.34 \times 10^{10} \frac{\rho_b}{\Delta t_s^2}
\]  \hspace{1cm} \text{...............(2.27)}

\[
E = 2G(1+\nu)
\]  \hspace{1cm} \text{...............(2.28)}
Where $\Delta t_s$ is the shear wave travel time (sec/m), and $\Delta t_c$ is the compressional wave travel time (sec/m) and $\rho_b$ is the bulk density (g/cm$^3$).

The typical responses of a sonic log to varying soil layers are depicted in Fig 2.30.

2.6.2 Lithology Logs

As the name implies, these logs are useful in describing the different layers encountered as the borehole is drilled and also to identify geometry of fractures present. They are used in pre-fracture and post-fracture formation evaluation. Types of lithology logs include: temperature logs, gamma ray logs and spontaneous potential (SP) logs. Temperature logs are shallow investigative tools, used to infer fracture height, but are inadequate for use in deviated boreholes. A comparison of pre-fracture and post-fracture temperature logs is also useful in determining changes to formation, well bore and temperature gradient after completion operations (Jones and Britt, 2009). Fig 2.31 shows temperature logs depicting conductivity and fluid movement effects, before and after fracturing. Gamma ray log is another widely used lithology log. Fracture azimuth is determined using a shielded gamma ray log and gyroscope, with the fracture geometry being traced with radioactive tracer (Jones and Britt, 2009).

2.6.3 Logging while Drilling (LWD)

The meaning of this logging technique is evident in its name. It simply means, carrying out logging at the same time drilling is done. LWD is very popular with development of unconventional reservoirs such as the Barnett shale. Early horizontal drilling in Barnett shale, made use of LWD, particularly gamma ray logs (Quinn et al, 2008). An example of an LWD gamma ray log is shown in Fig 2.32. It shows bedding planes and fractures using an LWD electrical image. Over the years, major advances in LWD operations have been made. Real-time, visually clear LWD images
describing fracture orientation are now possible, such as those shown in Fig 2.33 (depicting drilling-induced tensile fractures).

2.6.4 General Log Characteristics of Gas Shale

Orlandi et al (2011), lists the following as typical log behavior in gas shale reservoirs:

1. High gamma ray (GR) activity because of its high uranium content. The presence of uranium can be associated with organic matter. Hence Schmoker (1981) proposed a relationship between the total organic carbon (TOC) and gamma ray activity. A plot of TOC log and GR log is shown in Fig. 2.34.

2. Considerable resistivity due to the presence of kerogen and non-conductive gas.

3. Lower bulk density than surrounding rock, because of organic content in the shale rock matrix.

4. Increase in travel time of compressional waves because of the presence of organic matter. Acoustic compressional waves have low velocity in kerogen.
CHAPTER 3 – FRACTURE GEOMETRY

In the design of hydraulic fractures, most procedures to optimize well productivity begin with the fracture size. There are several approaches proposed to obtain the optimum fracture size, these have been documented by vast technical literature on the subject. Limitations in the different hydraulic fracture design methods are inherent in their assumptions of fracture geometry, dependence on fracture fluid/reservoir properties, layered formations and other factors like stress intensity. According to Robert Kennedy et al (2012), challenges in fracture geometry when fracturing unconventional reservoirs include: fracture azimuth and dip, not creating expected length, brittle and ductile rocks – complex and simple networks, well bore axis (vertical or horizontal drilling).

In all cases however, knowledge of existing in-situ stress tensors is essential to developing a fracture propagation model which describes the methods of obtaining a desired hydraulic fracture geometry definitely including the fracture (half) length, width, height and fracture complexity. There are new techniques of creating complex fracture networks with low viscosity fluid and multi-stage fracturing methods.

G. Hareland and P.R Rampersad (1994) propose the following factors to be considered in optimizing hydraulic fracture design for low permeability gas reservoirs:

1. The relationship between fracture dimensions and reservoir production.
2. The suitability of materials required for the fracture operation (propping agents, fracturing fluid etc).
3. The relationship between cost of fracture operation and reservoir properties (yield)
3.1 – In-situ stress Determination

Since the classical Hubert and Willis (1957) paper on hydraulic fracture mechanics, it has been proven both theoretically and empirically that hydraulic fractures propagate in a plane perpendicular to the least principal stress (Zoback and Haimson, 1981). In deep formations (≥300m) because of considerable overburden stress, this least principal stress is usually the minimum horizontal stress $\sigma_h\text{min}$. Geologically, this is true in normal and strike-slip faulting environments but in reverse faulting environments, the least principal stress is the vertical stress. The magnitude of this minimum horizontal stress can be obtained from the pressure in the fracture, immediately after pumping has stopped called the instantaneous shut-in pressure (ISIP). The maximum horizontal stress, $\sigma_h\text{max}$ is also useful in well bore stability analysis such as determination of optimal mud weights, well trajectories, casing set points and determination of possibility of shear failure on pre-existing faults. Despite its importance in geomechanics, the $\sigma_h\text{max}$ is the most difficult stress tensor to obtain accurately, particularly as it cannot be measured directly (Zoback, 2012).

As stated previously, the most important pre-fracture stimulation parameter to be obtained is the minimum in-situ horizontal stress, also taken for the sake of simplification as the closure pressure. The limitations of this assumption will be explained in a later section. The closure pressure is defined as the fluid pressure required in commencing the opening of a fracture. Closure pressure is of critical importance in obtaining reasonable predictions of hydraulic fracture geometry for a given net pressure and to evaluate proppant strength requirements (Jones and Britt, 2007). Field in-situ stress measurement is not a straightforward technique. Many variables that affect measurement are involved, for instance: the effects of perforations and propagation of the fracture beyond the zone that is being tested. However, by monitoring bottom hole treating pressure (BHTP), injection
fall-off and flowback tests, accurate values of in-situ stress can be measured (Holditch et al, 1987). The apparent drawback of using methods such as logs and core analysis to approximate in-situ fracture closure stresses is that they must all be calibrated by fracturing rock. Hence when a definitive value is required, injection tests are more suitable in obtaining closure stress values; there are three fundamental testing methods used (Jones and Britt, 2007):

1. **Pump-in/shut-in tests (Also known as injection fall-off tests)**
2. **Pump-in/flowback tests (Also known as injection flowback tests)**
3. **Step-rate injection tests (used to measure fracture extension pressure)**

The ideal formation evaluation would be one where the values of in-situ stresses obtained from injection tests and those calculated from logs and core analysis all result in a consistent stress profile (Holditch et al, 1987). It is worthy to note that there are several different methods of measuring rock in-situ stress, including: relief methods, jacking methods, borehole break out methods, strain recovery methods, acoustic emission methods, fault-slip data analysis, earthquake focal mechanisms etc but for the purpose of this thesis and considering the prevailing in-situ stress determination methods for pre-fracturing, only hydraulic methods will be considered. The hydraulic methods are also the most reliable for determining in-situ stress in deep (> 50m) formations (Amadei and Stephansson, 1997), hence its emphasis is justified.

Several variations occur for the two pump-in tests outlined above. In both cases, the closure pressure is obtained by a change in the pressure decline properties as the fracture closes (J. Jones et al, 2007). Theoretically, the pump-in/shut-in test can be taken to be a special case of the pump-in/flowback test provided the flow rate is set to zero (Hsiao C. et al, 1990). The pump-in/flowback test can be carried out separately or concurrently with the pump-in/shut-in test. The pump-in/flowback test is operationally more difficult to perform than the pump-in/shutdown test.
because of the need to maintain a constant and correct flowback rate as the pressure declines. If the pump-in/flowback test is done properly however it can be compared with results from the pump-in/shut-in tests to show consistency (Middlebrook et al, 1997). Generally, the pump-in/shut-in test is used for obtaining fluid loss to the formation and fracture geometry, while the pump-in/flowback test is used for obtaining closure stress (Hsiao and Tsay, 1990). This is especially true for low permeability formations like shale, where the pump-in/flowback test is more suitable for closure stress determination because extensive pressure decline monitoring is required to achieve fracture closure pressure (J. Jones et al, 2007). Summary of plots for shut-in and flowback tests ranging from normal pressure versus time plots to G-function plots are shown in table 3.1.

3.1.1 Pump-in/Shut-in Tests

This test is conducted by pumping in a fluid at a rate sufficient to create a fracture, then shutting in the well and allowing the pressure to decline to below closure pressure. The instantaneous shut-in pressure, ISIP is the pressure obtained at the instant when pumping is stopped and the well is shut-off. It is the pressure at which a fracture stops propagating and closes immediately after pump shut-off. It is always larger than the closure pressure because a fracture cannot start to close instantly when pumping is terminated (J. Jones et al, 2007).

Conventionally, in a pump-in/shut-in test, a log-log plot of the pressure difference versus shut-in time is used to identify the existence of linear or bi-linear flow. A one-half slope, before fracture closure normally indicates the existence of linear flow, as depicted in the $\Delta P/\Delta t$ slope in Fig. 3.1. While a one-quarter slope indicates bi-linear flow as depicted in the $\Delta P/\Delta t$ slope in Fig. 3.2. In the case of linear flow, the closure pressure can be obtained from the (linear/log-log) plot of the bottom hole treating pressure (BHTP) against square root of elapsed time, evaluated for the different pumping cycles. It is the point at which the graph deviates from a straight line. Also, for a
bi-linear flow the fracture closure pressure can be determined from a (linear/log-log) plot of the bottom hole treating pressure (BHTP) versus one fourth root of the shut-in time (Hsiao and Tsay, 1990). This value is checked for different cycles to ensure reasonable consistency.

In a pump-in/shut-in test, ISIP can be obtained from normal plots of pressure versus time, log-log plots and semi-log plots of pressure versus time. The reason for the use of these different plotting techniques will be discussed later. The normal plot of pressure versus time has the advantage of giving accurately the length of shut-in time, since real time values are plotted (Jones and Britt, 2007). In a normal plot, the ISIP value is obtained from the point in which the graph deviates from a straight line (Fig. 3.3)

There are however, a number of factors that complicate the determination of $\sigma_{h\text{min}}$, these include:

1. **Multiple Shut-In Pressures**

   In cases such as reverse faulting environments, where the least principal stress is the vertical stress, a vertical fracture forms at the well bore at an azimuth perpendicular to $\sigma_{h\text{min}}$ (assuming no natural fissures like joints or sub-horizontal bedding planes are present), and rotates into a horizontal plane perpendicular to the vertical stress as it propagates away from the well bore. Hence, the plane pressure decreases as fracture plane rotates. This effect is frequently observed at shallow depths ($\leq 300\text{m}$) and doesn't influence results significantly as long as proper interpretation of pressure-time history is done (Zoback and Haimson, 1982). This is shown in Fig. 3.4 which show pressure records of pump-in tests taken in shaly dolomite near Anna, Ohio.
2. Decrease in shut-in pressures

Another factor observed, is the decrease in shut-in pressures as fractures are propagated. These have been explained by Hickman and Zoback in 1982 to be due to viscous effects of fracturing fluid. Thus, the shut-in pressure that should be used as a measure of Shmin are the final values of shut-in pressure (Zoback and Haimson, 1982). This is shown in Fig. 3.5, which are results from a well drilled in granitic rock near Monticello, South Carolina.

3. Gradual pressure changes upon shut-in (Indistinct ISIP)

In this case, the pressure change after shut-in is too gradual to obtain any distinct measurement of shut-in pressure from the normal plots of pressure vs time. This is caused primarily by leak beyond the intervals, past the packers or further propagation after pumping stops, (Zoback and Haimson, 1982). Various methods have been proposed by investigators to solve this problem. Amadei and Stephansson (1997) explain these various methods of interpretation of shut-in pressures using data obtained at the Aspo Hard Rock Laboratory for nuclear waste disposal in southeast Sweden. These are shown in figs 3.6 to 3.12. Klasson (1989) suggested a method of using the inflection point after shut-in to determine ISIP. This makes used of double tangents to obtain points of intersection from the pressure decay curves. This method is depicted in figs. 3.6 to 3.8. It can be seen that the drawing of the tangents depend on personal judgement which is a drawback.

An alternative method of interpretation of shut-in pressure is called the exponential pressure decay method or Muskat method. The basic assumption of this technique is that pressure decay after fracture closure approaches an asymptotic value in an exponential manner (Aamodt and Kuriyagawa, 1983). The shut-in pressure is obtained by plotting In(P-P∞) against time, where P∞ is the asymptotic pressure (apparently the rock formation pore pressure). This is shown in fig. 3.9.
Another graphical method utilizing inflection points for shut-in pressure determination is one proposed by McLennan and Roegiers (1983). It involves a semi-log plot of pressure vs log \((t+\Delta t)/t\) where \(t\) is time of pressurization and \(\Delta t\) is the length of shut in time. This is shown in fig. 3.11. This plot, also called Horner plot can be used to identify radial flow and estimate reservoir pressure (Jones and Britt, 2007). See fig. 3.11.

As reported by Amadei and Stephansson (1997), the bilinear pressure decay rate method of Turnbridge (1989) has become the most reliable and most popular method for the determination of shut-in pressures. The fundamental concept of this method is that the shut-in pressure decay curve can be expressed as a flow rate out of the borehole, since the drop in pressure following shut-in must be related to the quantity of fluid flowing out the system into the hydraulic fracture, and to the quantity of fluid from other sources of leakage (Turnbridge, 1989). Turnbridge showed mathematically that the plot of rate of pressure decay versus pressure should consist of two line segments and the intersection of these segments give an estimate of the ISIP, as shown in Fig. 3.12. More rigorous methods to single out the shut-in pressure by using nonlinear regressional analysis to obtain the best fitting linear curve have been done by Lee and Haimson (1989).

3.1.2 Pump-in/Flowback tests

In a pump-in/flowback test, injection is followed by a flowback at a constant rate through a flowback manifold. This flowback rate is maintained with adjustable choke valves and a low-rate flowmeter. The primary purpose of the flowback is to establish a rate that is approximately equal to the fluid leak off rate to the formation. At this flowback rate, a typical reverse curvature occurs in the pressure decline at closure pressure. A trial and error procedure is then carried out to obtain the ideal flowrate by performing the first flowback (at 1 to 2 bbl/min) and changing the rate until an “s- shaped” pressure decline curve is obtained. The pump-in/flowback test is carried out again to
confirm repeatability (Jones and Britt, 2007). A major advantage of the pump-in/flowback test which will be re-emphasized here is that in shale, the created fracture may not close in a reasonable amount of time due to its low permeability or the fluid loss properties of the drilling mud (conducting the shut-in test is not practical), hence the flowback test can be used to induce the pressure decline in a controlled manner (Lee et al, 2004).

An extra derivative plot of dp/dt can be used to carry out additional analysis for the pump-in/flowback tests. Since, the closure is identified as the point at which the rate of decline accelerates, closure would be identified with the maximum point on the derivative plot (Jones and Britt, 2007). See fig. 3.13. Because of the operational difficulty in maintaining a constant (and correct) flow rate in the pump-in/flowback test it is often used as a last resort for determining fracture closure pressure.

Raeen A.M et al, (2001) using field data obtained from different offshore locations in Norway showed how pump-in/flowback tests reduce estimates of minimum horizontal stress significantly and the conventional extended leak-off tests (XLOT) or mini-fracs overestimate the minimum horizontal stress by at least 20 bars. He proposed a system stiffness approach for interpreting pump-in/flowback tests, based on the following, “In a flowback test we may estimate the system stiffness by dividing the change in system pressure by the corresponding flowback volume, subject to the condition that the flowback rate is much larger than the leak-off rate to the formation. In practical situations this is often ensured by low formation leak-off due to tight formations or an effective mud cake. By flowing back as fast as possible, the error due to fracture leak-off may be minimized”. The fracture stiffness, S in the form of an ellipsoid, for an open fracture and considering flowback (non-propagating) conditions is given as:

$$ S = \frac{\Delta P}{\Delta V} = \frac{3}{16}\frac{E(1 - v^2)}{R^3} $$

(3.1)
Where \( R \) = fracture radius, \( E \) is Young’s Modulus and \( \nu \) is Poisson’s ratio. These are properties of shale. Raaren noted that the fracture width isn’t contained in the equation hence the fracture stiffness will be constant during flowback, assuming the fracture closes by reducing its width with the length constant.

### 3.1.3 Step-rate Injection tests (SRT)

In a step-rate test, the injection is performed at constant, incrementally increasing rates and the final injection pressure for each step rate is plotted separately against pump rate as shown in fig. 3.14. A typical SRT, showing a plot of final pressures versus pump rate for a number of (fixed flow) step rates is illustrated in fig. 3.15. Each rate is usually maintained for fixed periods of time, usually 1 to 2 minutes.

The primary goal of the SRT is to obtain the fracture extension pressure, which is obtained as the break point in the bottom hole final pressure vs pump rate plot shown in figs 3.14 and 3.15. Alternatively, the fracture extension pressure can be determined by shutting down after each rate step and obtaining the ISIP. Then plotting the ISIP from each rate step as a function of pump rate and identifying the inflexion point. The fracture extension pressure is also a good upper bound on the closure pressure (Jones and Britt, 2007)

Every data collection program should include SRT because it is useful not just in determination of the fracture extension pressure but also in obtaining the fracture closure pressure.

### 3.2 Mini-fracture tests and G-function Analysis

Mini-fracture tests, commonly known as mini-fracs or extended leak off test (XLOT) are performed to obtain important understanding of the geomechanics of hydraulic fracturing stimulation. These tests are carried out using the planned fracturing fluids, pumped at the planned pump rates but
scaled down fluid volumes. Important information on fracture geometry, in-situ stress contrast, and fluid loss coefficient/fracture fluid efficiency can be obtained from properly designed and executed mini-fracs (Jones and Britt, 2007). It is important to note that both of the previously described pump-in/shut-in test and pump-in/flowback tests are variants of the XLOT. One basic difference is that the shut-in and flowback tests do not use the fracture fluid for injection.

A schematic pressure-time history illustrating an extended leak-off test (XLOT) or mini-frac is shown in Fig. 3.16. The linear portion of the plot shows a constant pumping rate (pressure versus time) and a fixed well bore volume. At the pressure where there is a distinct deviation from linearity (referred to as the leak off point or LOP), a hydraulic fracture is created. This is explainable because at constant pump rate, the well bore pressure will not decrease unless there is a considerable increase in the system volume into which injection is taking place. Also, the pressure in the well bore must be sufficient to propagate the fracture far from the well bore to cause a system volume increase large enough to affect fluid pressure. Thus, “there must be a hydraulic fracture propagating away from the well bore perpendicular to the least principal stress in the well bore region, once there is a noticeable change in the pressurization rate” (Zoback, 2012). It is reasonable therefore to say that a distinct leak off point, LOP is approximately equal to the least principal stress, assuming well bore resistance (caused by high flow rate and high viscosity) and tortuosity effects between created fracture and well bore are ignored (Fig 3.17). This fact, is the reason why in typical oil-field practice, leak off tests are stopped after LOP instead of conducting complete, extended leak-off test (Zoback, 2012). However, a comparison of LOTs and XLOTs will be done later in the section to adjudge the appropriateness of this practice.

### 3.2.1 Standard Leak off tests

The industry’s ambiguous nomenclature has defined LOTs in several ways. However, there are two main types of leak off tests (LOTs): Pressure Integrity Test (PIT) and Formation Integrity Test (FIT).
The PIT is a leak off test in which the pressure is increased until the pressure rate decreases, which indicates that leak off has occurred (Addis, 1998). In the FIT, pressure is applied to a pre-defined value and no leak off occurs. The FITs merely indicate that the maximum well bore pressure did not exceed the least principal stress or was not sufficient to initiate a fracture of the well bore wall in an open hole test (Zoback, 2012). Table 3.2 gives a classification of pressure tests, making reference to Figs 3.18 to 3.20. Leak off tests are performed immediately beneath cemented casing in order to test the integrity of the set cement and determine the drilling fluid density for the next drilling operations. The well is shut-in at the beginning of the test, and fluid is pumped into the well bore to gradually increase the pressure that the formation experiences. The test is normally stopped shortly after the LOP is reached. For over 40 years, LOTs have been used to determine stress for drilling, planning, sealing capacity of faults, mud weight design, well bore stability etc. The fact that LOTs are simple, cheap and similar to hydraulic fracturing tests make them an attractive test option (Gang et al, 2009).

As reported by Gang et al, 2009 in saturated rocks with low permeability, the pore pressure is often assumed to be unaffected by the state of stress and the Terzaghi’s effective stress is applicable to tensile cracks.

From classical theory of elasticity, considering stresses around a circular opening,
\[ \sigma_{\text{nat}} = \sigma_{\text{hmin}} + \sigma_{\text{hmax}} + 2(\sigma_{\text{hmin}} - \sigma_{\text{hmax}}) \cos 2\alpha \]  

\[ \text{At } \alpha = 45, \]

\[ \sigma_{\text{nat}}^{\text{max}} = 3\sigma_{\text{hmin}} - \sigma_{\text{hmax}} \]

Fracture will initiate if,

\[ \sigma_{\theta} \geq T \]

Considering pore pressure and leak-off pressure,

\[ \sigma_{\theta} = P_{\text{lo}} + P_{p} \]

Combining equations 3.3 to 3.5

\[ \sigma_{\text{hmax}} = 3\sigma_{\text{hmin}} - P_{\text{lo}} - P_{p} + T \]

For fracture re-opening, Plo becomes Pr and the tensile strength is no more significant, since fracture initiation has already occurred (Gang et al, 2009),

\[ \sigma_{\text{hmax}} = 3\sigma_{\text{hmin}} - P_{r} - P_{p} \]

Where \( \sigma_{\text{nat}} \) is natural hoop stress, \( P_{p} \) is the pore pressure, \( T \) is the tensile strength of the borehole formation. \( P_{lo} \) is the leak-off pressure. Unlike in hydraulic fracturing techniques, the leak-
off pressure instead of the shut-in pressure is taken to be equal to the minimum horizontal stress,

\( \sigma_{h\text{min}} = P_{lo} \)

It should be noted that the above formula has found application only in shallow formations (≤2km) where both stress and temperatures are low, and in vertical boreholes for leak-off tests yielding horizontal fractures.

The drawbacks of the LOTs lie in the assumption that the fracture initiation pressure (\( \sigma_{h\text{min}} \)) is equal to the leak-off pressure since the pressure required to equilibrate the fracture normal stress is the shut-in pressure. Also, the ISIP that can be used to estimate the \( \sigma_{h\text{min}} \) is mostly obtained in the 2\(^{nd}\) or 3\(^{rd}\) cycle of pressurized loading and not in the first cycle as assumed by LOTs (Gang et al., 2009).

### 3.2.2 Extended Leak-off tests

The execution of extended leak-off tests (XLOTs) is similar to LOTs, the main difference being the additional pressurization cycles, this is better shown in fig. 3.17. The XLOTs share a similar theoretical framework with the hydraulic fracture stress measurements. Considering, an ideal poroelastic rock, when a fracture is created and oriented coaxially with the hole, the magnitude and orientation of Shmin in the plane perpendicular to the hole’s axis can be obtained from the shut-in/closure pressure (Addis et al., 1998). The magnitude and orientation of the Shmax can be obtained from the fracture orientation.

Addis et al, 1998 modified the Haimson-Furst equation and present it as follows:

For fracture initiation,

\[
\sigma_{h\text{max}} = 3\sigma_{h\text{min}} + T - kP_{lo} - (2-k)P_p
\]  

For Fracture re-opening,
\[ \sigma_{hmax} = 3\sigma_{hmin} - kPr - (2-k)Pp \] 

where \( k \) is a poro-elastic constant.

A limitation of the XLOTs is that the orientation of the fracture isn’t known, hence the direction of the horizontal stresses cannot be determined (Gang et al, 2009).

**Comments on LOTs, XLOTs and Hydraulic Fracturing**

There have been several papers written comparing the XLOTs and LOTs, with a view of stating their inherent differences and comparing their functionality. Gang et al, 2009 gave his critique of LOTs (PITs) as follows:

Comparison of LOTs and Hydraulic fracturing

1. LOTs are carried out without a downhole packer, which is essential in hydraulic fracturing to ensure a well-defined seal-off zone.

2. In deep wells, a large volume of drilling fluid (30 to 200m³) is used to pressurize the bottom hole. This isn’t done in hydraulic fracturing to eliminate problems due to pressurizing large fluid volumes.

3. Neglecting shear stresses can cause serious errors especially in the inversion process of LOTs.

   The inversion process referred to here is with reference to inclined wells.

4. Mud compressibility, casing expansion and leakage of the casing cement can influence pressure records from LOTs thus undermining their usefulness in stress field predictions.

5. If the open-hole portion of the well exceeds a few meters in length, the leak off test data is not suitable as a good estimate for stress due to the influence of pre-existing cracks. The test will most likely re-open the preexisting fractures than generate a new one. A hydraulic
fracturing method specialized in stress measurements for such situations is called a HTPF (Hydraulic test for preexisting fractures).

Some of the above listed limitations like number 1 can be attributed to XLOTs. Gang et al (2004) compared XLOTs and Hydraulic Fracturing as follows:

1. Non-Newtonian fluid is used in XLOTs which make the test interpretation more difficult than hydraulic fracturing tests which use water or brine.
2. Rotation of fractures can occur as a result of fast pumping rate of large volumes of water in XLOTs.
3. Lack of fracture orientation data is still a drawback in XLOTs, consequently making them less reliable than hydraulic fracturing tests.

It is worth noting that the volume of fluid pumped in leak-off testing is significantly smaller than hydraulic fracturing and normally limited both horizontally and vertically to a few borehole radii. We can deduce from this that because of the small volume pumped during leak off tests, the fracture created is not sufficient to measure far field stresses. However, leak off tests still gain popularity in practice for the Oil and Gas industry. Normally, hydraulic fracturing is performed in rocks with considerable permeability and leak-off testing (LOTs and XLOTs) is commonly performed in shales which possess substantially lower permeability (Lee et al, 2004).

3.2.3 Case study Comparison of LOTs and XLOTs

A more quantitative comparison of the XLOTs (ELOTs) and LOTs was done by Addis et al, (1998) based on data obtained from six XLOTs conducted by the Australian petroleum industry on the North West Shelf of Australia. These are represented in tables 3.2 and Fig. 3.21. Also, data from standard LOTs and XLOTs conducted on wells drilled by Norsk Hydro in the Oseberg field of the Norwegian North Sea were analyzed, as seen in table 3.4 and fig. 3.23 and fig. 3.24.
As reported by Addis et al. (1998), in the pressure vs time plots of figure 3.21, tests in wells 1 to 3 are considered good quality tests (Ideal cases of XLOTs and LOTs are represented in Figs 3.18 to 3.24) because they indicate:

i. Well defined peaks in the first pressurization cycle proving new fracture initiation

ii. Well constrained shut-in curves indicative of negligible fluid leakage to the formation

iii. Approximately equal shut-in pressures for each cycle depicting consistent fracture orientation, with regards to stress fields

iv. Distinct pressure rebound between pressurization cycles

v. Well-defined fracture re-opening pressure, clearly shown in the third cycle of pressurization.

Tests on wells 4 to 6 are adjudged poor since they have indistinct peaks in the first pressurization cycle, which may be reflective of pre-existing fractures rather than generating a new fracture. These tests aren’t entirely unusable as the minimum stress may still (but with some uncertainty) be estimated from the lowest shut-in pressure.

**Data Interpretation from tests**

**The North West Shelf of Australia**

Table 3.2 shows the shut-in pressures from XLOTs in wells 1 to 3 and the lowest shut-in pressures of tests 4 to 6. The minimum stress has an average gradient (i.e. average between the six wells in table 3.3) of 14.25kPa/m (0.63 psi/ft) that is fairly consistent through the good quality (1 to 3) and poor quality (4 to 6) XLOTs. It was obtained from shut-in pressures using the double tangent method (shown in figs 3.6 to 3.8) for the pressure vs square root of time plots of the Norwegian data. Since this minimum stress value is significantly lower than the vertical stress (21.95Kpa/m or 0.95 psi/ft) as seen in stress plots of fig. 3.22, we can confidently assume the minimum stress acts in the horizontal direction. The scattered values in fig. 3.22 between the overburden stress profile...
and the minimum stress profile are the leak off pressures obtained from other standard LOTs from vertical wells in the same area. It is distinctively seen that the minimum stress form a lower bound to the leak-off stress pressures. The maximum stress values of table 3.2 were obtained from equation 3.8, assuming a poro-elastic constant, k of unity.

The Oseberg field in the Norwegian North Sea

The data for the Norwegian North Sea are represented in the tables 3.4 and figs 3.23 and 3.24. The wells tested in fig 3.23 are vertical (<10 degree inclination). The average minimum stress gradient, 16.72Kpa/m (0.738psi/ft) which shows an acceptable range of consistency (16.46KPa/m to 17.23KPa/m) forms a lower bound to the leak-off pressures obtained from the standard LOTs. The leak off pressures occur between the overburden stress and the minimum stress (broken lines on plot) as occurred in the data from the North West Shelf. However, in figure 3.24 where data from wells inclined at up to 66 degrees are recorded it is clear that a substantial number of leak off pressures now fall below the minimum horizontal stress gradient. This shows that leak off pressure values that match fracture initiation pressures, which usually decrease in inclined wells. It can also be inferred that that the leak-off pressure gradient decreases by 0.15kPa/m for every 10 degree of well inclination, assuming effects of wall orientation are neglected (but can affect leak off pressures), (Addis et al, 1998).

In most situations, the XLOTs have been shown to be better estimates of the minimum horizontal stress than standard LOTs. Generally, the LOTs and XLOTs are performed in shale and mudstone formations which typically have the highest stresses and fracture gradients. Transferring such data for stress field predictions in formations with low stress gradients such as reservoir sandstones or limestones is not advisable (Addis et al, 1998).
3.2.4 G-Function Derivative Analysis

As previously stated, one of the parameters that can be obtained from the mini-frac test is the fracturing fluid efficiency. This is defined as the fracture volume (at the end of pumping) divided by the total slurry volume pumped. It is a measure of fluid leakoff, (Jones and Britt, 2007). The total volume lost between \( t_p \) and \( t_p + t_c \) is the volume of the fracture at \( t_p \). Dividing this volume by the total volume injected gives efficiency.

Where \( t_p \) is the elapsed time between fracture initiation and shut-in, \( t_c \) is the time between shut-in and when the fracture closes. \( t_i \) is the time between start of pumping and fracture initiation. \( t_p + t_c \) is the total time between fracture initiation and closure. From a plot of fluid efficiency versus the fracture closure time (\( t_c/t_i \)),

Jones and Britt (2007) give this relationship:

\[
\rho \frac{V_f}{V_L} = \frac{e_f}{1-e_f}
\]

\[
\frac{V_f}{V_L} = \frac{e_f}{1-e_f}
\] \hspace{1cm} (3.10)

where \( e_f \) is the fluid efficiency, \( V_f \) is the fracture volume and \( V_L \) is the fluid loss volume during injection. \( (1-e_f) \) gives the volume of fluid lost to the formation while pumping. Thus \( V_L *(1-e_f) \) gives the total slurry volume pumped. \( \rho \) is a new variable which is used in G-function analysis described later, it is given by:

\[
\rho = \frac{\pi}{4K} G_0 \Delta p
\]

\[
\frac{\pi}{4K} G_0 \Delta p
\] \hspace{1cm} (3.11)

Where \( G_0 \) is the pressure difference function equal to 1.57-0.238 \( e_f \), \( \Delta p \) is the match pressure and \( K \) is a correction to the fluid-loss coefficient that accounts for additional fluid loss during pumping such as spurt loss or losses due to pre-existing fractures (Jones and Britt, 2007). Parameters from
the fluid efficiency equations also find use in G-function analysis as will be shown further. Fluid efficiency can also be used exclusively for preparing fracturing treatment design schedules.

The G-function derivative analysis is basically a manipulation of dimensionless time. It is another method of analyzing pressure records from the mini-frac test to obtain better estimates of minimum stress. It is useful in representing non-ideal decline behavior by creating plots of pressure vs G-function and dp/dg as a function of g function. G-function is also defined as the representation of the elapsed time after shut-in, normalized to the duration of fracture extension, (Barree et al, 2009). Barree et al, (2009) presents multiple analysis techniques (involving G-function) for holistic interpretation of mini-frac tests. These multiple analysis methods are done for different cases, including: pressure dependent leakoff, fracture tip extension and variable fracture storage as shown in figs. 3.25 to figs. 3.27. Barree et al made a derivation of G-function, assuming high fluid efficiency in low permeability formation.

The dimensionless pumping time used in the G-function is defined as:

\[ \Delta t_0 = \frac{(t-t_p)}{t_p} \] 

\[ \Delta t_0 \] = (t-t_p)/t_p  

\[ \Delta t_0 \] = (t-t_p)/t_p  

Where t = tp +tc: total time from start of fracture initiation to closure

Considering low leak-off, the dimensionless time (\( \Delta t_0 \)) is used to compute an intermediate function,

\[ g(\Delta t_0) = \frac{4}{3} [ \left(1+\Delta t_0 \right)^{1.5} - \Delta t_0^{1.5}] \] 

\[ g(\Delta t_0) = \frac{4}{3} \left[ \left(1+\Delta t_0 \right)^{1.5} - \Delta t_0^{1.5} \right] \] 

\[ g(\Delta t_0) = \frac{4}{3} \left[ \left(1+\Delta t_0 \right)^{1.5} - \Delta t_0^{1.5} \right] \] 

The G-function used in the diagnostic plots shown in Figure 3.2 L –N is derived from the intermediate function as shown below:

\[ G(\Delta t_0) = \frac{4}{\pi \Delta t_0} [ g(\Delta t_0) - g_0 ] \] 

\[ G(\Delta t_0) = \frac{4}{\pi \Delta t_0} \left[ g(\Delta t_0) - g_0 \right] \] 

Where \( g_0 \) is the dimensionless fluid loss volume function at shut-in (ie when t=tp and \( \Delta t_0 =0 \)). All derivatives are calculated using a central difference function of pressure and G-function (normalized shut-in time).
3.3 2D Geometry Models

3.3.1 Howard and Fast Fracture Area/Extent

According to G. C. Howard and C.R Fast (1970), fracturing fluid and reservoir rock properties have significant effects on fracture penetration. R.D Carter derived an equation for calculating the area of a hydraulically induced horizontal or vertical fracture. Among the assumptions he made in deriving his equation are: 1. Uniform width of the fracture 2. Linear flow of fracturing fluid from fracture and perpendicular direction of flow from the fracture face 3. The velocity of flow into the formation at a point is dependent on the duration of flow (time-dependent flow). Howard and Fast’s assumed fracture geometry is shown in Fig. 3.28

G.C Howard et al (1970) publish Carter’s derivation as follows:

Volume rate at which fluid flows linearly from fracture into the formation is given by,

\[ i_L(t) = 2 \int_{0}^{Af(t)} v \, dA_f \]  

\[ \text{..................................................(3.15)} \]

Af is the area of fracture, v is the velocity of flow and iL is the volume rate

Since \( Af \) is a function of time, and the value of \( v \) corresponding to a given element \( dA_f \) at time \( \Delta \) is \( v(t-\Delta) \), thus:

\[ i_L(t) = 2 \int_{0}^{t} v \, (t - \Delta) \, dA_f / dt \]  

\[ \text{.........................(3.16)} \]

The rate at which the fracture volume is increased is:

\[ Q_f = W \, dA_f / dt \]  

\[ \text{.................................(3.17)} \]
Where \( W \) is the fracture width

The injection rate of fluid, \( I \) is the sum of the rate at which fluid flows to the formation, \( i_L \) and the fracture volume increase, \( Q_f \). That is:

\[
I = i_L + Q_f \tag{3.18}
\]

Subs. Eqns 3.16 and 3.17 into 3.18,

\[
I = 2 \int_0^t v(t - \Delta) \frac{dA_f}{dt} + W \frac{dA_f}{dt} \tag{3.19}
\]

Solving using Laplace transformation,

\[
Af = \frac{BW}{4pC^2} \left( e^{x^2} \cdot erf \left( \frac{x}{\sqrt{\pi}} \right) + \frac{2}{\sqrt{\pi}} x - 1 \right) \tag{3.20}
\]

Where \( x = \frac{2C\sqrt{\pi} t}{W} \) \tag{3.21}

This equation clearly shows that the pump rate is directly proportional to the fracture extent.

The coefficient, \( C \) is the fracturing fluid coefficient. It is sometimes referred to as the fluid leak off. It is determined by the fracture fluid properties and the reservoir fluid and rock characteristics. The value of \( C \) is obtained from the flow mechanism during injection of fracturing fluid. A high coefficient means high fluid loss, while a low coefficient means low fluid loss. Low fluid loss properties during treatment mean a larger fracture area for a given volume and injection rate since there is less fluid lost ineffectively to the formation during treatment. Thus, \( C \) relates the fracture extent to the aforementioned properties, G.C Howard et al (1970)
Linear Flow Mechanisms

According to G.C Howard et al (1970), there are three types of linear flow mechanisms defined by the fracturing fluid coefficient, $C$. Thus, the value of $C$ depends on the mechanism encountered. The value of $C$ in mechanisms 1 and 2 can be obtained from reservoir data and existing charts. The third mechanism however has to be obtained experimentally because it involves fluid loss. It is important to note here that for fractures in horizontal wells, the flow is linear between the fracture and the reservoir, but inside the fracture near the well, the flow changes from linear to radial, this results in a considerable reduction in flow rate from each individual transverse fracture compared to fracture in a vertical well (Valko et al, 2005). Thus, these three linear flow mechanisms can only be applied to a horizontal well, when considering the flow to the reservoir normal to the fracture. Hydraulic fracture in a horizontal well will be treated in a later section.

The three linear flow mechanisms are:

**Mechanism 1** - The effect of fracturing fluid viscosity and relative formation permeability, $C_1$

This occurs under conditions of injecting a highly viscous fracturing fluid at constant pressure, given by,

\[
\text{Linear flow velocity, } v = \frac{i}{A_f} = \sqrt{\frac{k \Delta p \phi}{2 \mu t}} = C_1/\sqrt{t} \quad \text{..................(3.22)}
\]

\[
C_1 = 0.0469 \sqrt{\frac{k \Delta p \phi}{\mu}}, \text{ ft/min}^{0.5} \quad \text{..................(3.23)}
\]

Where, $k$ is the formation permeability (darcies), $\Delta p$ is the difference in pressure between the fluid at the formation face and the far-field fluid in the formation (psi), $t$ is the time (mins), $\mu$ is the viscosity at bottom hole conditions (centipoise, temperature effects accounted for), $\phi$ is the porosity.
Mechanism 2- The effect of fracturing fluid viscosity and compressibility effects of reservoir fluids, C2

This occurs when the fracturing liquid has similar physical properties with those of the reservoir fluid. In this case, the fluid flow rate is determined by both the coefficient of compressibility of the injected fluid and the existing reservoir fluids.

Linear flow velocity, \( v = \frac{\Delta p}{k\phi c/\mu \pi t} = \frac{C2}{\sqrt{t}} \) ..................................................(3.24)

\( C2 = 0.0374 \frac{\Delta p}{k\phi c/\mu \pi}, \text{ft/min}^{0.5} \) ..................................................(3.25)

Where \( n \) is the porosity and \( c \) is the fluid compressibility (measured in \( \text{psi}^{-1} \)).

Mechanism 3- The effect of wall building fracturing fluids, C3

As reported by, G.C Howard et al (1970), it is possible to determine experimentally from actual formation cores, the fluid loss characteristics of fracture fluids that contain fluid loss additives, by plotting the empirically obtained cumulative filtrate volume vs the square root of flow time. The straight line relation obtained is given by,

\[ V = m\sqrt{t} + V_{sp} \] ..................................................(3.26)

\( m \) is the slope of the straight line relation of the plot. Obtaining \( C \) from this mechanism is explained in detail in section 4.2.3 of the next chapter. The intercept, \( V_{sp} \) is the spurt loss. This increases the fracture width, \( W \) shown in eqns 3.19 to 3.21.

The flow velocity is obtained by differentiating eqn 3.16 with respect to \( t \) and dividing by \( A_c \) which is the cross-sectional area of the medium through which the fracture takes place (packers). \( A_c \) is the diameter of the well x length between the packers.
Linear flow velocity, \( v = \frac{q}{A} = \frac{1}{A_c} \frac{dV}{dt} = \frac{1}{2Af} \frac{m}{\sqrt{t}} = \frac{C_3}{\sqrt{t}} \) ..........................(3.27)

\[ C_3 = 0.0164 \frac{m}{Ac}, \frac{ft}{\sqrt{min}} \] ..........................(3.28)

3.3.2 The PKN and KGD Geometries: Fracture width

In the past, hydraulic design procedures were mostly based on the Perkins and Kern (PK) and the Khristianovich and Zheltov (KZ) models, excluding numerical simulation methods. In these two models, the fracture width and length are functions of the continuity, elasticity and fluid flow equations (G.R Hareland and P.R Rampersad, 1994) Both of these 2D propagation models assume constant height along the fracture length. The principal difference in assumptions being plain strain on the vertical plane for the PK model and plane strain on the horizontal plane for the KZ models.

The PK method is suitable for long fractures \( (x_f/h_f \geq 1) \), while the KZ model is more appropriate for short fractures \( (x_f/h_f \leq 1) \), (Van Eekelen, 1982). The two models are mutually exclusive, elegant methods and cannot be used interchangeably, Valko et al (2005)

Perkins and Kern Model

Perkins and Kern originally developed their 2D model for hydraulic fracture prediction, which was further modified by Norgden and became the PKN model. Peter Valko and Michael Economides, (2005) describe the PKN condition, saying the vertical plane strain along a fracture with length greater than height \( (x_f/h_f \geq 1) \) allows vertical planes to slide against each other. This is shown in fig 3.29. Thus, in the PKN model, the formation stiffness is concentrated in vertical planes perpendicular to the direction of the fracture propagation, Van Eekelen (1982). The fracture cross section in this plane is assumed elliptical and the formation stiffness in the horizontal plane is
discarded, as depicted in fig 3.30. The fracture height is assumed to be constant. The half-length is obtained by procedures discussed in section 2.2.2 of chapter 2.

Valko at al(2005) present the PKN width equation as:

\[ W_{max} = 3.57 \left( \frac{\mu x f}{E} \right)^{\frac{1}{2}} \]  

…………………(3.29)

where \( W_{max} \) = maximum fracture width at the well bore, \( \mu \) = viscosity of fluid injected, \( x_f \) = fracture length, \( I \) = injection rate and \( E \) = modulus of elasticity of rock (Young’s Modulus).

Considering the shape factor, of the well bore, the average fracture width is:

\[ W_{avg} = 2.24 \left( \frac{\mu x f}{E} \right)^{\frac{1}{2}} \]  

……………………………(3.30)

Valko further coupled the PKN width equation by material balance, considering constant fluid injection rate and no leak off. The net pressure in the well bore was obtained as:

\[ P_{net} = 1.52 t^5 \left( \frac{E^4 \mu^2}{h f} \right)^{\frac{1}{4}} \]  

………………………………(3.31)

where \( P_{net} \) = net pressure at well bore, \( t \) = time , \( h_f \) = fracture height.

In a different review of the PKN model, Jones and Britt (2009) present relations as follows:

\[ P_{net} = (P - \sigma c) \alpha \left[ E^4 \left( \frac{\mu x f}{E'} \right) + \frac{Kic^4}{h f^2} \right]^{\frac{1}{4}} \]  

………………………………(3.32)

\[ W_{avg} \alpha \left[ \left( \frac{\mu x f}{E'} \right) + \frac{Kic^4}{E^4} \right]^{\frac{1}{4}} \]  

………………………………(3.33)

Where \( E' \) is the plain strain modulus, \([E/(1-v^2)]\), \( E \) is the Young’s modulus and \( Kic \) is the apparent fracture toughness.

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The Khristianovich and Zheltov model

The Khristianovich and Zheltov model was further developed by Geertsma and deKlerk to become the KGD model. In the KGD model, the formation stiffness is concentrated in the horizontal plane, Van Eekelen (1982) Due to the horizontal plane strain condition, the resulting fracture cross-section is rectangular, (Valko, 2005) with the formation stiffness in the vertical plane discarded as shown in figs 3.31 and 3.32.

Valko et al(2005) present the KGD width equation as:

\[ W_{max} = 3.22 \left( \frac{\mu x^2 f}{E h_f} \right)^{\frac{1}{4}} \]  \hspace{1cm} (3.34)

Considering the shape factor, of the well bore, the average fracture width is:

\[ W_{avg} = 2.53 \left( \frac{\mu x f}{E h_f} \right)^{\frac{1}{4}} \]  \hspace{1cm} (3.35)

Considering constant injection rate and no leak off, the net pressure is given by:

\[ P_{net} = 1.09 t^{-\frac{1}{3}} \left( \frac{E^2 \mu}{x^2} \right)^{\frac{1}{4}} \]  \hspace{1cm} (3.36)

Comparing the average widths of the PKN and KGD models,

The ratio of the average KGD width to the PKN model is

\[ 0.95 \left( \frac{2 x f}{h f} \right)^{\frac{1}{4}} \]  \hspace{1cm} (3.37)

The equations of average fracture width and net pressure for the PKN and KGD models were derived considering Newtonian behavior of fracture fluids. However for design consideration, most fracturing fluids exhibit non-Newtonian behavior (G. Hareland et al, 1994), according to the power law:
\[ \tau = k \left( \frac{du}{dy} \right)^n \]  
\[ \text{...........................................(3.38)} \]

A suitable way of adding Newtonian behavior to the width equations is to include another equation that links the equivalent Newtonian viscosity, \( \mu_e \) to the flow rate, thus the PKN and KGD width equations will be in terms of the power law width parameters.

**Radial Width Equation**

In the case of a radially propagating fracture, that is \( xf = hf/2 = R \). Fig 3.33 depicts radial fracture. A modified PKN or KGD equation can be written as follows:

\[ W_{avg} = 2.24 \left( \frac{\mu R}{E} \right)^{\frac{1}{4}} \]  
\[ \text{...........................................(3.39)} \]

In another paper, Jones and Britt, 2009 give the following relations for a radial fracture, where

\[ P_{net} \propto \frac{E'}{R} \left( \frac{\mu R}{E'} \right)^{\frac{1}{4}} \]  
\[ \text{...........................................(3.40)} \]

\[ W_{avg} \propto \left( \frac{\mu R}{E} \right)^{\frac{1}{4}} \]  
\[ \text{...........................................(3.41)} \]

**3.3.3 Fractures in horizontal wells**

In horizontal wells, transverse fractures are relatively more difficult to achieve than longitudinal fractures. However, for shale gas formations normally characterized by low permeability, transverse fractures in horizontal wells have greater production benefits (Valko et al, 2005). Transverse vertical fractures move along the path of least resistance, which is normal to the minimum horizontal stress as shown in fig. 3.34. In horizontal wells or deviated wells, there are effects in the immediate vicinity around the bore that lead to the transverse fractures taking tortuous paths before eventually becoming normal to the horizontal stress (fig. 3.35). These effects
are increased by the presence of natural fractures in the formation and the deviation of the horizontal well at an angle from the minimum horizontal stress, shown in fig. 3.36

### 3.3.4 Fracture Geometry in Layered Formations (Fracture Height)

The simplified geometry proposed by the PKN and KGD models are not adequate when considering multi-layered formations. This is because the different layers have varying properties such as: elasticity, fracture toughness, ductility, permeability and interface bonding (Van Eekelen, 1982). Thus different fracture widths are expected at the different layers (see fig. 3.37). Also, the PKN and KGD models assume a constant fracture height, which is estimated based on “barrier action” of rock layers above and below the zone of interest (Van Eekelen, 1982). This estimated fracture height further affects the calculation of length, width and proppant transport.

Proppant screenout is the inhibition of proppant transport to the target formation. It can be caused by the existence of layers of higher stiffness, between target formation layers as shown in 3.38. This can cause the termination of treatment, as depicted in fig. 3.39 (Valko et al, 2005).

To account for the stiffness effects of multi-layered formations and design fracture heights accordingly, pseudo-3D models have been developed.

### 3.3.5 Economics of 2D models: Optimum Fracture half-Length

This dimension is of interest to the oil and gas prospecting industry because the goal of hydraulic fracture design is to maximize the post treatment performance and subsequent benefits at the lowest treatment costs (Valko et al, 2005). Fracture conductivity, width and height are all determined with respect to a fixed fracture length (G. Hareland et al). Thus, the propped width, fracture permeability, assumed fracture half-length and the reservoir permeability are used to estimate post treatment performance. This enables the prediction of future incremental benefits,
which when discounted to the present gives the net present value (NPV) of the revenue. The treatment costs are determined from the estimates of required fracturing fluid volume, proppant quantity, injection rate etc and subtracted from the present value to obtain the NPV for the particular fracture half-length (Valko et al., 2005).

The fracture half-length cannot be arbitrarily made to be long, because longer lengths require higher treatment costs. Also, longer lengths do not always increase the NPV. From the figs 3.40, a comparison of gas produced from different fracture half-lengths is done. The maximum revenue is not strictly the shortest or longest production duration. “The best production period is based on the NPV which is a function of fracture length” (Hareland et al, 1994). In the low permeability, shale gas reservoirs the longer fracture length may start with a high rate of production but eventually decline after a short period, this is shown in fig. 3.41. Thus, a unique fracture half-length has to be determined for every specific case, considering the reservoir characteristics. (Hareland et al,1994)

Typically half lengths range from less than 100m for a high permeability formation to more than 500m for a low permeability reservoir (Valko et al, 2005).

3.4 Other Geometry Models

3.4.1 Pseudo 3D Models

Abundant technical publications exist within the petroleum industry that describe pseudo 3D models, simplified 3D models and fully 3D models. Simplified 3D models identify the fracture shape based on the rock characteristics but do not fully solve the fluid flow problem, which is solved in the more complex full 3D models (Holditch et al, 1987). Pseudo 3D (P3D) models are useful approximations, because of the prohibitive complexity of the 3D models. In P3D models, the
pressure drop, width and equilibrium height are calculated along the fracture length (Barree et al, 2009). Several variations of P3D models exist but the fundamental difference between the P3D and 2D models is that the fracture height isn’t constant along the length.

A typical hydraulic simulation involves the solution of the elastic continuity equation, which relates pressure to crack opening and the constitutive equations that describe fluid flow. Early development and testing of a Pseudo 3D model was proposed by Settari and Cleary (1986). Initial P3D models assumed a 1D fluid flow for long fractures (high fracture length/width ratio), although incorporation of 2D flow in P3D models has since been advanced (Xiaowei). Typically, in a P3D model, the fracture is divided into vertical sections and each section is taken to be a 2D vertical crack as shown in Fig. 3.42 (Xiaowei,1992). Xiaowei Weng (1992) presents a study comparing the original P3D models (that assume 1D flow); a modified P3D model (considering 2D flow) and the full 3D models. Xiaowei, illustrates the equations of a conventional P3D model as follows:

The crack opening pressure, is related to the minimum stress and fracture width, by:

\[ P(x,z) - \sigma(z) = \int_{h_l}^{h_u} \Gamma(z,z_0) \frac{db}{dz_0} dz_0 \]  
(3.42)

Where \( p \) = fluid pressure, \( \sigma \) = minimum horizontal stress, \( b \) = fracture width, \( h_u \) and \( h_L \) = upper and lower heights, and \( \Gamma \) = influence function.

Assuming 1D flow, the pressure drop is a function of the vertical, \( z \) co-ordinate and the continuity equation across the P3D model section is given by,

\[ \frac{\partial q_z}{\partial z} + q_L + \frac{\partial b}{\partial t} = 0 \]  
(3.43)

where \( q_z \) = flow-rate in the \( z \) direction. \( q_L \) is the leak-off rate. \( q_L \) is given as,

\[ q_L = \frac{2C}{\sqrt{t-\tau}} \]
where \( C \) = fluid leak-off coefficient and \( \tau \) is the fluid arrival time. Equations 3.33 and 3.34 can be used to determine the fracture width, pressure distribution and height growth rates.

The pressure gradient/flow relation is given below:

\[
- \frac{\partial p}{\partial z} = 2K' \left( \frac{4n'+2}{n'} \right)^{n'} q^2 b^{(2n' + 1)} \]

…………………………..(3.44)

where \( n' \) and \( K' \) are the power-law and fluid-consistency indices respectively, considering Non-Newtonian behavior.

Xiaowei further proposed a modified Pseudo 3D Model that assumes a 2D continuity equation for fluid flow across the sections. This is shown below:

\[
\frac{\partial q_x}{\partial x} + \frac{\partial q_z}{\partial z} + q_L + \frac{\partial b}{\partial t} = 0 \]

……………………………..(3.45)

where \( q_x = \) flow-rate in the \( x \) direction

He considered a modified radial flow field for a penny shaped fracture, as shown in Fig. 3.43 and Fig 3.44. The inner region exhibits horizontal flow, while the outer region shows radial flow. The direction of radial flow shown is perpendicular to the fracture boundary. Also, the streamlines diverge significantly for the penny shaped \( (h=2L) \) than for the near-well bore region of elongated fractures \( (L>h) \)

Xiaowei gives the continuity equation for the assumed radial flow in the outer region as:

\[
\frac{1}{r} \left( \frac{\partial}{\partial r} \right) (r q_r) + q_L + \frac{\partial b}{\partial t} = 0 \]

……………………………..(3.46)

Where \( r = \) radial distance from imaginary source and \( q_r = \) radial flow rate. Revising this equation by changing the derivative with respect to \( r \) to one with respect to \( z \), he obtained,
\[ \frac{\partial}{\partial z}(rq) + zqL + z(\partial b/\partial t) = 0 \] ..........................(3.47)

The pressure gradient/flow relation now changes to:

\[ - \frac{\partial p}{\partial z} = 2K' \left( \frac{4n+2}{n'} \right)^n qr^{n-1} - qz \] ..........................(3.48)

where \( qz = qr\sin\theta \) and \( \theta \) is the angle of the streamlines measured from the horizontal axis.

The method of collocation using Chebyshev Polynomials, as done by Settari and Cleary (1986) was used by Weng to solve for width in equations (3.33) and (3.36).

A comparison between the conventional 2D, original P3D, Xiaowei-Modified P3D and fully 3D models was done. The fully 3D models were the Terra Tek and University of Texas models. Results of the predicted fracture geometries using these different models are shown in Fig. 3.45. From the results it is seen that University of Texas fully 3D models predicts narrower (smaller height) but longer (extended fracture half-length) than the P3D and the 2D models. The vertical KGD model predicts a shorter fracture but with greater height.

Currently available Pseudo 3D hydraulic fracturing simulators include: MFRAC, StimPlan, e-StimPlan, Frac Cade (Baree et al, 2009). An example of a StimPlan output is shown in Fig. 3.46.

3.4.2 Fully 3D Models

Fully 3D models to simulate hydraulic fracturing treatments have been developed. The fully 3D models have the capacity to describe more accurate fracture geometry but are more complex to execute. Fully 3D models formulated include one by Settari and Cleary (1984) and Van Den Hoek (1993). In the model developed by Settari and Cleary (1984), a set of equations were formulated, considering:
1. A 3D, two-phase flow in the reservoir.

2. Two phase Non-Newtonian fracture flow and heat transfer, considering losses due to overburden stress.

3. Vertical and lateral fracture propagation

4. Proppant transport, wellbore hydraulics, PVT relations and rheology characteristics of reservoir and fracture fluids.

The physical system of the Settari and Cleary model is shown in fig. 3.47. Settari and Cleary (1984) make an additional comparison of their model against the 2D models of fracture geometry using several examples. A drawback of the 3D model is its sensitivity to the many required input parameters and consequently, the difficulty in obtaining all the data necessary for the model’s successful application. Typical data required for the 3D model application is shown in Tables 3.5, 3.6 and 3.7.

The essential feature of the 3D model is its ability to predict fracturing pressures, see figs. 3.48 and fig. 3.49. The pressure response varies considerably, with almost constant pressure in the 3D high containment case. In the model example illustrated, the properties of the adjacent strata were unknown, so “high” containment and “low” containment are hypothetical upper and lower bounds of over-burden stress from layers surrounding the pay zone (Settari and Cleary, 1984).

Currently available 3D simulators, include: GOHFER, N-Stim Plan, FracPRO and Terra Frac. An example of a FracPRO output is shown in Fig. 3.50.
3.5 Direct mapping techniques for hydraulic fracturing

The two main technologies, available in the petroleum industry of directly mapping hydraulic fractures in order to obtain fracture geometry are the microseismic mapping and downhole tiltmeters. Each technology measures different features of the hydraulic fracturing process (Du et al, 2008). These two diagnostic tools are carried out at distances from offset wellbores and show the “big picture” of far-field fracture growth. One shortcoming of these methods is that they map the entire hydraulic fracture growth zone but give no information on the smaller details like the effective propped-fracture length or conductivity. The resolution of these technologies is inversely proportional to their offset distances from the fracture (Cipolla and Wright, 2002). The placement locations of these direct mapping techniques are shown in fig. 3.51

3.5.1 Tiltmeters (Surface and downhole)

Tiltmeters are highly sophisticated, extremely accurate biaxial instruments that use “bubble sensors” and “carpenter’s levels” to determine the change in angle of a surface (Jones and Britt, 2009). The principle of tiltmeters is quite simple. The creation of hydraulic fractures causes all-round deformation to the surrounding earth. This induced tilt (deformation) can be measured by downhole tiltmeters placed in nearby wellbores or surface tiltmeters located on the ground surface, assuming that the deformation is elastic, as shown in fig. 3.52. Surface tiltmeters measure the fracture orientation while downhole tiltmeters are used to obtain fracture geometry.

Surface tiltmeter

A typical tiltmeter array consists of 12 to 16 instruments installed in shallow holes (10 to 40 ft deep) and evenly spaced at radial distances ranging from a few hundred feet to as far as 1 mile around the treatment well, depending on the depth of treatment zone and anticipated fracture
dimensions. Tiltmeters are usually placed at a depth that is 0.4 x overall well depth (Cipolla and Wright, 2002). Each tiltmeter is packed into position using sand to protect the device from the effects of weather and noise interference as seen in fig. 3.53 (Jones and Britt, 2009).

The magnitude of induced deformation at the surface is so small –typically of order one ten thousandth of an inch (0.00001 in) because of the distance away from the fracture; hence it is impossible to measure deformation directly. Instead, the surface tiltmeters measure the gradient of the displacement or the tilt field which is a function of fracture azimuth, dip, depth to fracture center and fracture volume, as seen in fig. 3.54. The induced deformation is almost totally independent of reservoir mechanical properties and in-situ stress state. For instance, a north-south growing vertical fracture of given dimensions produces almost the same deformation pattern whether the fracture is in a low stiffness rock like diatomite, high modulus hard carbonate or unconsolidated sandstone (Wright et al, 1998). Surface tiltmeters are extremely sensitive and can measure changes in tilt of a surface with an accuracy of about 1 x 10^{-7} radians (Jones and Britt, 2009).

**Downhole tiltmeter**

Downhole tiltmeter mapping technology was developed to circumvent the limitations of the surface tiltmeter by giving estimates of the fracture dimensions. The downhole tiltmeters have the same operational principle as the surface tiltmeters, but instead of being at the surface, the tiltmeters are positioned by wireline in one or multiple offset wellbores at the depth of the hydraulic fracture. Typically, the array consists of 7 to 12 tiltmeters coupled to the borehole with standard oil-field centralizer springs (see Fig. 3.55) (Wright et al, 1999). Downhole tiltmeters provide a map of the deformation of the Earth adjacent to the hydraulic fracture. Thus, what is
obtained is an estimate of an ellipsoid that best approximates the fracture dimensions, as seen in fig. 3.56

Typically, downhole tiltmeters are located closer to the fracture than the surface tiltmeter and hence more sensitive to fracture dimensions (Cipolla and Wright, 2002). The closer the downhole tiltmeter to the fracture, the better the quality of data obtained to determine fracture height (Jones and Britt, 2009). Fig. 3.57 shows a downhole deformation pattern from tiltmeters in an offset well, at 100 ft from the injection (stimulated) well. As seen in the figure, the downhole array tilts in a continuous fashion, similar to surface tiltmeter records but the arrays span the same depth interval as the zone being fractured. The total interval covered by a downhole tilt array ranges from 300 ft to >1000ft, depending on the design conditions (Wright et al, 1998). Conventionally, surface and downhole tiltmeter analysis are done separately but techniques have been proposed to combine them for evaluating fracture geometry during drill cuttings disposal (Griffin et al, 2000).

The greatest advantage of both surface and downhole tiltmeter fracture mapping is that for a given fracture geometry, the induced deformation field is almost completely independent of formation properties. Also, the required degree of formation description is lower in tiltmeter mapping than microseismic mapping (velocity profiles, attenuation thresholds etc) as will be described in a later section. Complex fracture growth would yield independent fractures at different orientations or depths but in tiltmeter mapping a simpler analysis is required (Wright et al, 1998).

3.5.2 Micro-seismic mapping

Microseismic theory and mapping is based on earthquake seismology. Similar to earthquakes, but at a much higher frequency (200 to 2000Hz), microseismic events emit elastic P waves (compressional) and S waves (shear waves) (Jones and Britt, 2009). During hydraulic fracture, there is an increase in formation stress proportional to the net fracturing pressure, and an increase in
pore pressure due to fracturing fluid leak off. The increase in stresses at the fracture tip and pore pressure increments causes shear slippages to occur, as shown in fig. 3.58. Microseismic technology thus uses earthquake seismology methodologies to detect and locate these hydraulic fracturing induced shear slippages, which resemble micro-earthquakes. Fig. 3.59 shows a schematic of the hydraulic fracture creation and the tip and leakoff processes develop compressional and shear wave arrivals. Microseisms or micro-earthquakes occur with fracture initiation and are observed with receivers placed on an offset wellbore like with the downhole tiltmeters.

Microseismic mapping technology involves installing an array of tri-axial geophone or accelerometer receivers into an offset well at approximately the depth of the fracture (like in downhole tiltmeters) see fig 3.51, orienting the receivers (geophones), recording seismic data, finding micro-earthquakes in the data and locating them. Locating the earthquake events requires the determination of compressional (P) and shear (S) wave arrivals and consequent acoustic interpretation of the velocity of the P-S waves, as shown in fig. 3.60 (Du et al, 2008). The fig. shows a three component (tri-axial) geophone with P and S wave arrivals. Employing the arrival times on the X, Y and Z components, both location and direction of events can be obtained (Jones and Britt, 2009). Standard microseismic mapping use P-S arrival time separation for distance location. Horizontal and vertical plane hodograms are used to determine azimuth and inclination (Warpinski et al, 1995). [The hodogram is used to obtain information on the direction travelled by a wave before it is detected at the receiver, the motion of the receiver itself is plotted on the hodogram, see fig. 3.61 (Crewes.org)].

The distance, $d$ is computed, using the standard equation,

$$d = \frac{V_pV_s}{V_p-V_s} (t_s - t_p)$$

......................................................................(3.49)
Where Vp and Vs are the p-wave and s-wave velocities and tp and ts are the p-wave and s-wave arrival times respectively. This equation assumes that the formation is homogeneous and isotropic with constant acoustic velocities (Warpinski et al, 1995)

The micro-earthquake events are located using either regression algorithms or grid search methods, assuming that the velocity profile is known. The velocity profile is typically obtained from dipole sonic log measurements and its accuracy can be improved using perforation timing measurements (Du et al, 2008). Du et al, (2008) also propose a method of further improving the velocity profile by joint inversion using both downhole tiltmeter and microseismic mapping. The resulting microseismic data can then be used to obtain fracture azimuth and fracture geometry.

Further studies to integrate microseismic mapping, fracture modeling and reservoir simulation to optimize well performance has been done by Liu et al (2009) to optimize well performance in the Chanqing field, China. An example of practical model calibration using results from microseismic mapping and net pressure matching is given at the end of this chapter.

### 3.6. Net Pressure Matching and Calibration of Fracture Growth Models

Despite the efforts invested in the improvement of fracture models (pseudo3D models, fully 3D models etc), most field investigations reveal that fracture geometry obtained during stimulation, differ significantly from the model predictions. Barree et al, 2009 summarizes some of these disparities in common field observations as follows:

1. Less fracture widths than predicted.
2. High net treating pressures are frequently encountered.
3. Height containment is often better than predicted by models.
4. Shear failure occurs in the rock masses.

Weijers et al (2005) explains these differences in model predictions and field observations as follows:

1. Poor measurement of the critical input parameters (Young’s modulus, permeability and fracture stress) of the models, especially the fracture closure stress.
2. Lack of a complete understanding of all the physical mechanisms involved in hydraulic fracturing growth.
3. The high net treating pressures encountered in field observations as said by Barree et al, above is caused by complex fracture growth (multiple hydraulic fractures) which results in competition between opening fractures. Also, plastic deformation and creation of micro-fractures in the “process zone” cause increased fracture growth resistance at the tip leading to higher observed net treating pressures.

A detailed look at Weijers et al explanation above, reveals the importance of adapting the basic hydraulic fracturing models to fit the specific formation being stimulated. In other words, to “calibrate” the models, based on observation of the actual fracture. Fracture models show how changes in a fracture treatment should affect the fracture geometry, but as described earlier has a vague relationship with reality. Direct mapping can measure the fracture geometry of a specific treatment but cannot predict what changes can occur if the treatment is altered. The synergy of direct measurements with fracture models gives calibrated fracture models with better prediction capabilities (Weijers et al, 2005). Thus, the model can now be used to make predictions when parameters are varied during fracture injection.

This is a two-fold process; it means firstly modifying the models to match parameters observed through pressure tests i.e. net observed pressures. Secondly, calibrating the model by adjusting
calculated geometry to match fracture dimensions “seen” via direct mapping (microseismic mapping or downhole tiltmeters). They might be obtained either in real-time or post-fracture stimulation.

3.6.1 Net Pressure History Matching

The net pressure is a very important parameter in fracture growth prediction. It can be measured directly in the field to interpret the fracturing process. The net treating pressure as defined by the relationship in equation (3.32), differs most times from the observed net pressures (Jones and Britt, 2009). The process of changing model inputs and assumptions to calculate a model pressure that matches the observed net pressure response is called net pressure history matching (Weijers et al, 2005). The fig 3.62 shows bottomhole pressure (BHP) history matching for modeled and observed cases in unconventional gas wells. The diagram shows a good correlation between the plots of the actual BHP and simulated BHP (using model after history matching). The observed net treating pressure is given by the following equation:

\[ P_{\text{net,obs}} = P_{\text{surface}} + \Delta P_{\text{hydrostatic}} - \Delta P_{\text{friction}} - \sigma_{\text{closure}} \] .................................(3.50)

It is worthy to note that the Bottom Hole treating pressure (BHTP) is the sum of the first three terms of the equation.

Weijers et al, (2005) presents the determination of terms of the equation (3.46) as follows:

\( P_{\text{surface}} \) is obtained from surface pressure measurements throughout the treatment.

\( \Delta P_{\text{hydrostatic}} \) the hydrostatic head is obtained from calculation of quantity of fluid injected and knowing the density of fluid components
The three main friction components are: wellbore friction, perforation friction and near-wellbore friction. Wellbore friction is determined from flow loop tests and near-wellbore friction is obtained from step rate tests (SRT).

The fracture closure stress in the pay zone is obtained from pressure decline analysis, usually through LOTs or XLOTs.

Although several companies have developed software for calculating BHTP from surface pressure, to date no technique has been developed to accurately explain all variables affecting friction pressures (Jones and Britt, 2009).

The earliest attempt to understand the varying behavior of observed net treating pressure was done by Nolte and Smith (1981). They developed a diagnostic framework for pressure monitoring, as shown in fig 3.63. The figure shows a log-log plot of fracturing pressure vs pump time. The interpretation of the plot is based on the work of Perkins and Kern (1961) and Nordgren (1972), which show that net pressure is proportional to time raised to an exponent (Jones and Britt, 2009).

A summary of the interpretation of the different modes in the Nolte-Smith plot is given by Jones and Britt, 2009 below:

Mode I – Confined-height extension

A log-log net pressure to pump time slope of $1/8$ to $1/4$ implies that the fracture is propagating with confined height and unrestricted extension, that fluid loss is linear-flow dominated (See section 3.1.1). Also, the injection rate and fluid viscosity are fairly constant. These assumptions are supported by the PKN model.

Mode II – Constant height growth
This flat pressure-time slope indicates that the predicted net pressure increase is reduced by either stable height growth or increased fluid loss. As expected, this mode of net pressure increase is temporary, because the balance of fracture growth and fluid-loss which maintains this constant pressure with time is easily disturbed when the height growth reaches a low stress zone or vice versa (formation inhomogeneity). This leads to mode III or IV.

Mode III – Restricted extension

This mode is a region of positive unit slope (1:1 log-log slope). It shows a build-up of pressure due to a restriction in fracture growth. This could be caused by a high stiffness barrier action.

Mode IV – Uncontrolled height growth

The negative slope is as a result of rapid and unstable height growth into a region of low closure stress. If a negative slope is observed at the start of the hydraulic fracturing treatment, it indicates a lack of height confinement. This shows that the fracture will grow radially, and future treatments should be designed using a radial model.

The Nolte interpretation guide is a powerful tool for explaining what causes the observed net pressure, which is a first step to pressure matching. However, the main interest of pressure matching is not only in the interpretation of pressure behavior but the adjustment of the model to fit the observed pressure. Table 3.7 shows the eight general parameters adequate to create a net pressure history match for a fracture treatment.

Some of these parameters would be referred to, in the fracture model calibration example in section 3.6.2. These parameters are adjusted in the model, so that the calculated net pressure matches the observed net pressure. In so doing the predicted fracture geometry using the same parameters would be similar to field fracture growth.
3.6.2 Fracture Model Calibration

Net pressure matching alone (to describe fracture growth) is an indirect diagnostic technique, hence the need to complement its results with direct diagnostic technology like microseismic mapping. Two of the matching parameters listed in table 3.7 are not considered in current fracture models. These are width decoupling and composite layer effect. They are explained with figs. 3.64 and fig 3.65. The consequence of changing the width decoupling parameter in the model is that the fracture width becomes the half-length. The result of accounting for the composite layer effect in the model is that the fracture height is exchanged for the half-length. (Weijers et al, 2005).

An advantage of calibrating the model is that the user better understands the reservoir that he/she is completing thus understanding properties like fracturing fluid effects in the pay zone and during proppant transport, permeability, closure stress, level of far-field fracture complexity, composite layering effects etc. This knowledge can then be applied to treatment decisions, for instance knowing that due to tip effects, multiple fractures would be created as fracture propagates one could realize that certain fracture lengths are not achievable. It may require increasing drilling fluid density or to use fracture using another means like changing fracture azimuth or horizontal completions (Lehman et al, 2002).

Practical Model Calibration (Weijers et al, 2005)

An example of a model calibrated with field measurements is illustrated in figs. 3.66 and 3.67. In fig 3.66, a plot of net pressure versus time is shown from a propped fracture treatment. The high initial net pressure during the breakdown (at 180 min) was matched to significant tip effects. To match the increasing net pressure, seen throughout most of the fracture treatment, fracture growth complexity was assumed. In this case, the closure stress contrast of the barrier-payzone was high but still lower than the 2000 psi of net pressure observed at the peak of the net pressure plot (see
The closure stress contrast is the difference in stress between the pay zone and the surrounding barriers. The higher the closure stress contrast, the higher the net pressure required for out-of-zone fracture growth. As shown in the top section of fig. 3.67 in the width profile, significant out-of-zone fracture growth still occurred later in this case. A fracture half-length and total fracture height of 250 ft was obtained using the FracPRO PT 3D simulator.

Results from microseismic mapping, however showed a fracture height of only 130 ft and a fracture half-length of 700 ft which differs greatly from the un-calibrated pressure matching aforementioned results. The net pressure history matching had to be carried out again to account for directly observed geometry. To achieve the directly mapped results, it was determined that a closure stress gradient in excess of 1 psi/ft had to exist in the shales surrounding the pay zone. Since this wasn’t practical, the composite layering effect was added to the model to account for the observed level of material confinement. The immediate result of this confinement layer was an increase in net pressure, hence both tip effects and fracture complexity had to be reduced to maintain a net pressure match. Also due to longer fracture length (700 ft) the fracture surface area in the pay zone increased considerably, so the reservoir permeability and wallbuilding coefficient had to be decreased in order to maintain a match of leakoff characteristics. The bottom portion of fig. 367 shows the final fracture geometry of the calibrated model. The resulting calibrated model can now be run in predictive mode to evaluate alternative designs (Weijers et al, 2005).
CHAPTER 4 – FRACTURING MATERIALS

Hydraulic fracturing is carried out using two broad classes of fracturing materials: fracturing fluid and proppants. Fracturing fluid is a generic term, that involves both the base fluid (water, oil, acid etc.) and additives. Additives are chemicals added to influence the overall properties of the fracturing fluid. Propping agents or proppants are materials used to stop the fracture from closing after treatment. They effectively “prop” or hold the fracture open to enable hydrocarbon recovery.

The comprehensive design and selection of these fracturing materials is paramount to successfully achieve desired fracturing objectives. A lot of factors are considered in the choice of fracturing fluid, additives and propping agents. The process of selection though is a subjective process: factors considered range from job experiences, formation evaluation, laboratory test results and so forth.

In this chapter, the function of conventional fracturing fluids and additives are outlined; and selection approaches for both fracturing fluids and proppants is discussed.

4.1 Fracturing Fluids

The effectiveness of a hydraulic fracturing operation is controlled by several variables, but only a few are easily controlled, these are: the fracturing fluid properties, the injection rate and the quality of propping agents (Pye and Smith, 1973). The fracture fluid design is an essential part of the hydraulic fracturing stimulation treatment. Fracture fluids can be classified into four main divisions based on their fluid bases: oil-based, water-based, foam-based and alcohol-based, see table 4.1 below (Xiong et al, 1996). For decades, oil based fluids were in use and skepticism followed water-based fluids. It was thought that pumping water into water sensitive formations (oil reservoirs) would obstruct oil flow. However success of water based fluid experiments led to their eventual wide usage with two-thirds of wells now being fractured with water based fluids (Howard et al, 1970). Water base fluids have considerable advantage over other bases, including: non-
inflammability; higher specific gravity thus lower hydraulic horse power (HHP) for treatment; low viscosity making it easier to pump, finally low cost and ease of availability.

This has found even more application with gas prospecting, as the fluids currently being used for hydraulic fracture treatments in the Marcellus shale are water based or mixed slick water fracturing fluids (Arthur, 2008). Slick water fracturing fluids consist mainly of water mixed with friction reducing additives like potassium chloride. As reported by Robert Kennedy et al (2012) “High rate slick water fracturing can induce tensile fractures as well as shear existing fractures in the brittle shale formation with low horizontal stress anisotropy. Slick water fracturing has become the norm in Barnett and Marcellus shale plays”. The disadvantage of slickwater fracturing fluids is that due to its low viscosity, it is not an efficient carrier of proppants. Hence, though successful in several US shale developments, it has not been suitable for all cases (R kennedy, 2012). In cases where slickwater is inadequate, hybrid fracs have been proposed. A hybrid frac is a combination of slickwater (to create the fractures) and another more viscous fracturing fluid (solely for proppant transport) (King, 2010). Careful selection of fluids and proppants (sand constituents) is necessary based on the reservoir properties of the specific shale formation. As reported by R. Kennedy, “No two shales are alike” (King, 2010). The table 4.2 outlines suggested fracture treatment types and pump rates for dry gas, wet gas and oil.

4.2 Additives

Additives are chemicals added to the fracturing fluid to achieve specific target properties of the fracturing fluid. They constitute between 0.1 to 0.5 % of the total fracture fluid volume as shown in Fig. 4.1. The figure shows volumes of additives in a hypothetical 2,500,000 gallon fracture treatment, a size typically used in Marcellus shale horizontal well development, (Arthur et al, 2008).
General properties that should be possessed by a fracturing fluid include: low leak off rate, the capacity to transport a propping agent and low pumping friction loss. Low leak off rate allows the fluid to create the fracture and influences the extent of the fracture area (Howard et al, 1970). To achieve low leak-off rate, fluid-loss additives are used. Capacity for proppant transport is influenced by density, viscosity and velocity of fluid flow. The viscosity is the most critical parameter in proppant transport as would be explained in later sections. Additives called viscofiers are used to enhance viscosity.

The type of additive used, also depends on the base fracturing fluid. For instance, water base fluid more than other base fracturing fluids; require surfactants to reduce interfacial tension and resistance to return flow after treatment. Conversely, additives for friction-loss reduction in fracturing are less needed for water-base fluids since it naturally has a friction-reducing advantage. The same considerations apply to other base fluids, with additives chosen to supplement their inherent limitations.

In a broad sense, additives serve the following uses: 1. Enhance fracture creation 2. Reduce formation damage. Additives that enhance fracture creation include viscofiers, temperature stabilizers, pH-control agents and fluid loss control materials. Those that reduce formation damage are gel breakers, biocides, surfactants, clay stabilizers and gases (P.C Harris, 1988).

4.2.1 Viscosifiers

As evident in the name, viscofiers are used to increase the viscosity of fracturing fluid. The most popular of these “fluid thickening” agents is Guar gum (Howard et al, 1970). Chemical modification of water base polymers obtained from guar has produced a wide range of derivatives with useful properties (shown in Table 4.1) such as: hydroxypropyl guar (HPG) and carboxymethyl hydroxypropyl guar (CMHPG). Hydroxylethyl cellulose and carboxymethyl hydroxyethyl cellulose
(CMHEC) are derivatives from cellulose, another natural source. These derivatives provide viscosity for fracturing wells with formation temperatures from 60 to more than 400 degrees Fahrenheit. To prevent loss of viscosity due to decomposition of these derivatives at high temperatures (above 225 degrees Fahrenheit), chemical stabilizers like methanol or thiosulphate are added. For lower temperatures (below 150 degrees Fahrenheit), aqueous solutions of these derivatives, known as base gels are used. (P.C Harris, 1988). When high viscosity is required, cross linking a polymer is normally done using transition metal cations which is more cost effective than merely increasing the concentration of the polymer solution.

R. Kennedy, 2012 asserts that “Low viscosity slickwater fluids generate fractures of lesser width and therefore greater fracture length, theoretically increasing the complexity of the created fracture network for a better reservoir to well bore connectivity” As stated previously though, slickwater is not an efficient proppant carrier due to its low viscosity. There is a tendency of proppants settling, which can be overcome by increasing the pump rate to increase flow velocities. Hybrid fracs can also be used, combining both slickwater and crosslinked fluid systems (highly viscous) to increase proppant transport capacity (Brannon and Bell, 2011).

4.2.2 Surfactants and Alcohol

This is another group of commonly used additives in a water-based fracturing fluid, known as surface active agents or surfactants. There are several uses of surfactants. These include: 1. Reducing interfacial tension and hence capillary pressure 2. Providing a foam stabilizing action 3. Reducing compatibility problems between fracturing fluids and reservoir fluids.

Decreasing the capillary pressure is useful in low permeability formations to reduce the pressure needed in causing flow back of fracturing fluid since less fluid will be retained in the pore spaces of
the reservoir. In fracturing fluid recovery, the addition of gases like nitrogen and CO2 are also useful (P.C Harris, 1988). The foam stabilizing action is effective in gas wells.

Investigators like McLeod and Coulter (1966) presented cases for the use of alcohol to lower interfacial tension. Its use in fracturing however has been limited because it is cost prohibitive. Another drawback to alcohol usage is that it impedes fluid-loss control and attainment of desired viscosity (Howard and Fast, 1970)

4.2.3 Fluid-Loss Additives

These materials are added to the base fracturing fluid to keep the fluid within the fracture, hence stopping it from leaking off into the rock matrix. This is of utmost importance, because loss of fluid through uncontrolled leak-off will cause an increase in proppant concentration around the well bore, which if allowed can create a “proppant bridge” and completely stop fracture propagation (P.C Harris, 1988). Fluid-loss control in fracturing operations cannot be over-emphasized. Low fluid loss (low leak-off rate) would mean larger and deeper fractures for a given volume of fracturing fluid and injection rate.

Hawsey and Jacocks (1961) describe the way the fluid loss additive functions, as follows: The fluid-loss additive which is largely insoluble, disperses into micron-size (μm) particles when added to the fracturing fluid. As fracturing takes place, some fluid is lost immediately to the formation, called “spurt loss”. After spurt loss, the fluid-loss additive deposits a thin film on the face (interior walls) of the newly created fracture, hence preventing further fluid-loss to the formation. It continues this as fracture propagates and new fracture area is exposed. This thin film is sometimes called a filter cake. The thin film would remain in place, as long as there is pressure in the fracture. When flowback begins, it re-disperses and flows out through the large gaps between propping agents. The spurt loss is an important part of the fracturing operation, since a good fluid-loss additive would not
only coat the fracture face but prevent excessive spurt loss from occurring. Spurt loss is defined as the fluid loss per area, before the formation of a filter cake, and is very significant in naturally fractured reservoirs (Jones and Britt, 2009). It is directly proportional to reservoir permeability.

In their 1961 paper on the use of fluid-loss additives in hydraulic fracturing of oil and gas wells, Hawsey and Jacocks (1961) present a test that demonstrates fluid-loss properties of a fracturing fluid. It was developed by an API sub-committee for measuring fracturing fluid efficiency. A pressure differential of 1000 psig was maintained in two different cells at a temperature of 125°F. The results of the test are recorded as fluid lost (in cubic centimeters) through a filter (core plug) in a 25 minute interval. Lease oil, an oil-base fracturing fluid was used in the two cells. The lease oil in cell 1 had fluid loss additives, but in cell 2 lease oil was used without any additives. Using the oil-base fracturing fluid, lease oil without additives signifies high fluid-loss to the filter medium (acting as formation) and lease oil with the additives is meant to depict low fluid-loss. The additive used in this experiment, is known commercially as Adomite Mark II. Natural sand was added to the fracturing fluid to serve as a proppant. The schematic diagram of the experiment is shown in Fig 4.2.

A plot of fluid loss against square root of time for the cell with fluid-loss control (additive) is shown in Fig 4.3. The spurt loss, which is the amount of fluid lost before fluid-loss control is obtained by extrapolating the fluid-loss line back to the y axis i.e. when time = 0. In this case, the slope, m = 0.5 and spurt volume, Vsp = 4.0cc. The fluid-loss coefficient, C can be obtained as follows:

\[ C = 16.4 \left( \frac{m}{a} \right) \]  

(4.1)

Where, a is the area of the filter(sq cm), and m is the slope of the fluid-loss curve. It gives a measurement of the fracturing fluid efficiency after spurt loss has ended. Thus, the lower the fluid-loss coefficient the higher the fluid efficiency. It should be noted, that this method of obtaining the
fluid-loss coefficient, C was explained in chapter 3, under section 3.3.1 “Mechanism 3 – The effect of wall building fracture fluids”

In this example, the filter area was 20.2 sq cm and a fluid-loss coefficient of 0.4 is obtained. In Fig 4.2d, a plot of fluid-loss coefficient versus fracture area and injection rate for a fluid volume of 15,000 gal is shown. Refer back to equation 3.20 to see governing equation of plot. A fluid loss coefficient of 5.0 (typical value without additive) would give a theoretical fracture area of 30,000 sq ft. If a fluid-loss additive is used and the fluid–loss coefficient is reduced to 0.4, as shown in this case, then for an injection rate of 25 bbl/min, the theoretical fracture area increases to 160,000 sq ft. The fracture area has been increased over five times. However, this theoretical area has to be corrected for spurt loss. Fig 4.5 shows a nomograph for this purpose. In this example, for a fluid-loss coefficient of 0.4, injection rate of 25 bbl/min, spurt loss of 4.0 cc, injection volume of 15,000 gal we obtain a factor of 73 percent from the nomograph. Hence, instead of a theoretical area of 160,000 ft, we have a spurt loss-corrected area of (0.73x160,000) = 116,800ft (Hawsey and Jacocks, 1961).

Despite the usefulness of fluid-loss additives, several investigators have shown that they severely reduce fracture proppant conductivity and formation permeability hence affecting well productivity. Pye and Smith (1973), conduct formation damage test using fluid-loss additives. They conclude that at FLA/sand ratios exceeding 0.03, their model shows reduction in conductivity of proppants, severe enough to make the fracturing treatment ineffective.

4.2.4 Clay Stabilizers

These are additives used to improve compatibility between the formation and fracturing fluid. Most formations contain clay minerals that are susceptible to swelling and migration. Clay damage is extremely important in low permeability, low pressure reservoirs as it affects capillary pressures
Fracturing fluids must provide a high electrovalent strength, so that clays contacted would not experience “ionic shock”. Clay stabilizers like inorganic salts such as KCl, NaCl, NH₄Cl, or CaCl₂ are used to prevent shocking the clays. Other stabilizers such as polymeric clay stabilizers can attach anions on the clay surface to control migration of fines (P.C Harris, 1988). This is useful, as invasion of fines hampers proper proppant placement.

4.2.5 Gel Breakers

These additives are useful for flowback and cleanup after the fracturing operation. It is important to ensure good fracture conductivity. Gel breakers oxidize the backbone of the polymer molecules, allowing the polymer to be produced out of the fracture. Enzyme breakers such as hemicellulose are used at temperatures below 120°F with a pH less than 8.5. Other oxidizing breakers like ammonium and sodium persulfate are used at higher temperatures, 150°F, or at lower temperatures with an activator (Jones and Britt, 2009).

4.2.6 Bactericides/Biocides

Biocides are additives for controlling bacteria growth and are often a necessity for water-base fluids. Investigators like Hawsey et al (1964) have shown that pumping untreated water into a reservoir can trigger bacteria growth (Howard and Fast, 1970). Aerobic bacteria can destroy the viscosity of a fracturing fluid within a few hours. If anaerobic bacteria is introduced by a fracturing fluid, it can produce hydrogen sulphide (H₂S) within the reservoir (P.C Harris, 2008). Biocides used to control both types of bacteria include quarternary amines, amide-type chemicals and chlorinated phenols (Howard and Fast, 1970).
4.2.7 pH Control

Fluid pH affects various properties of the fracturing fluid. These include: initial polymer gelation rate, crosslinking characteristics, gel break properties, bacteria control, viscosity stability and other properties. The typical pH range for fracturing fluid is from 3 to 10 (virtually the entire pH range). Buffers made from mixing weak acids with weak bases are used to maintain the desired pH (P.C Harris, 1988).

Jack and Britt (2009), group the selection criteria for fracturing fluid into the following:

1. Safety and environmental compatibility.
2. Compatibility with formation and additives.
4. Low pumping pressure.
5. Appropriate viscosity.
7. Flowback and cleanup (for high conductivity).
8. Economics.

Hongje Xiong et al (1996) propose an approach to select fracturing fluids and additives for fracture treatments using fuzzy logic. This is contained in the appendix.

4.3 Proppants

Proppants are used to prevent closure of the created fractures, in order to enable the flow of hydrocarbons from the reservoir to the wellbore (see Fig 4.6). The goal of proppants is to maximize fracture conductivity (i.e. flow path for hydrocarbons), thus the magnitude of fracture conductivity is a measure of proppant performance. Proppants are necessary because of the tendency of
fractures to heal (close) naturally after fracture creation. There are several types of proppants available commercially, including: sand, ceramic (glass beads), resin coated ceramic, aluminium alloys, nutshells, plastics (see Fig 4.7). These proppants are differentiated mainly by their specific gravity and strength. The cost of ceramic proppants range from 5 to 10 times that of sand (Jones and Britt, 2009). In this section, the key parameters that guide proppant design and selection are described.

4.3.1 – Proppant size and concentration

The proppant size is an important consideration for design and depends on the degree of stress, target conductivity, and achievable fracture width. The testing of proppant size distribution is a quality control procedure done through sieve analysis. The American Petroleum Institute (API) has two publications showing tests for sands, intermediate strength and high strength proppants: RP 56 1983 and RP 60 1989. According to API recommendations, for proppant size classification, more than 90% of the tested sample should fall between the designated sieve size, like 12/20, 20/40, 30/50 etc. Not more than 1% should be smaller than the smallest sieve size and less than 0.1% should be larger than the largest sieve mesh. Generally, fines are unacceptable as they reduce fracture conductivity, the maximum tolerable fines for proppants is 1% (i.e percentage that passes the BS #200 sieve) (Jones and Britt, 2009). The percentages given by Jones and Britt do not add up. It is recommended that classification of proppants can be done simply when 90% of the tested sample falls between the designated sieve sizes and fines tolerance limit should be observed.

The size and concentration of the proppants influences proppant placement in several ways (Cohen et al, 2013):

1. Larger proppants settle closer to the wellbore, due to their higher settling velocity (see Fig 4.8).
2. Proppant bridging occurs more easily in large proppants.

3. The higher the proppant concentration the more the apparent viscosity of the slurry, increasing the average width of the supported fracture and reducing the length.

4. Smaller proppants are transported a further distance and increase the chance of tip screenout.

Table 4.3 shows the effect of different proppant sizes on fracture geometry and fracture properties. The smallest proppant (80/100 mesh sand) maximizes the fracture length and consequently the Effective Stimulated Volume (ESV). While the largest proppant (20/40 mesh sand) banks (or bridges) in the vicinity of the wellbore (point 0) and maximizes the average propped conductivity (Cohen et. al, 2013). From this, it is seen that the largest proppant would be the preferred option if it can be transported far enough, since it would increase fracture height and hence conductivity. Cohen et al, (2013) also show a graph comparing production rate for fractures stimulated with proppants of different sizes (Fig 4.9). Initial production increases with proppant size but the production decline is faster. While for the smaller proppant size, the initial production is low but production decline is slower. Cohen et al, (2013) explain that the initial production is dependent on the pressure differential around the borehole caused by the conductivity. This is why it favors larger proppant sizes. In terms of production duration, the production rate of the larger proppant size depends only on the formation matrix permeability thus it declines faster. While that of the smaller proppant depends on both the formation matrix permeability and the conductivity of the fracture network, hence the longer it takes to decline.

Cohen et al, 2003 propose a method of gradually increasing the proppant size during injection for a single treatment. The pumping schedule for the combined-size treatment is shown in table 4.4. A
cumulative production plot comparing this combined-size treatment with single-size treatment is shown in Fig 4.10.

Proppant concentration is achieved by using pelletized spacer materials. The spacers should have the following qualities:

1. Similar specific gravity as the proppant
2. Easily transportable
3. Essentially insoluble in fracturing fluid, but soluble to post-fracturing injected solvents for easy removal
4. Resistant to breakage during pumping and ease of storage and handling in the field.

Three examples of spacers are: Urea (NH₂CONH₂), Hydrocarbon resin (soluble in naphthalenic and aliphatic hydrocarbons) and Sodium bisulfate (Howard and Fast, 1970).

4.3.2 – Proppant Shape

This consists of two main descriptions: roundness and sphericity. The roundness is a measure of the smoothness of the proppant, while the sphericity is how well it resembles a sphere (Jones and Britt, 2009). Krumbein and Sloss (1963) developed a chart of sphericity and roundness which is the most widely accepted till date (See Fig 4.11). API RP 60 working with the Krumbein and Sloss chart recommend that sand should have a minimum roundness and sphericity of 0.6, while ceramic proppants should have a minimum value of 0.7 (see Fig 4.12). At high stresses, say 4000psi the more spherical the proppant is, the more the permeability but at lower stresses, the more angular the proppant is the higher the permeability. Angular proppants tend to crush under high stresses, thus generating fines which lead to a reduction in conductivity (Jones and Britt, 2009).
4.3.3 – Proppant Stress

The stress in which the proppant would be subjected, is a critical factor to consider when selecting propping agents. The proppants have to be chosen, so that they do not crush under field closure stresses. Over the years, the traditional way of calculating closure stress, has been the minimum horizontal stress minus the bottom hole flowing pressure (measured at the start of production). The following sets of equations provide the theoretical framework for calculating the proppant stress.

The effective stress, $\sigma_{eff}$ is given by

$$\sigma_{eff} = \sigma_{ob} - \alpha p$$

………(4.2)

Where $\sigma_{ob}$ is the overburden pressure (normally estimated as 1 psi/ft), $p$ is the reservoir (fluid) pressure, $\alpha$ is the Biot-Willis poro-elastic constant (which is usually taken as 1)

The flowing bottom hole pressure, $p_{fbhp}$ is the pressure at the bottom of the wellbore when production starts, it is given as:

$$p_{fbhp} = ISIP - \sigma_{hmin}$$

……………. (4.3)

Where ISIP is the instantaneous shut-in pressure, $\sigma_{hmin}$ is the minimum horizontal stress

Theoretically, the minimum horizontal stress is given as follows:

$$\sigma_{hmin} = \frac{\vartheta}{1-\vartheta} (\sigma_{ob} - \alpha p) + \alpha p + p_{tec}$$

……………(4.4)

Where $\vartheta$ is the Poisson’s ratio, $p_{tec}$ is the tectonic stress (if known),

The traditional method of calculating proppant stress, $\sigma_{prop}$ is using:
\[ \sigma_{prop} = \sigma_{h_{min}} - p_{fbhp} \quad (Effective \ stress = Total \ stress - pore \ pressure) \quad \ldots\ldots(4.5) \]

Jones and Britt, (2009) present a modified Eaton’s equation for theoretically calculating proppant stress as follows:

\[ \sigma_{prop} = \sigma_{h_{min}} + p_{fnp} - p_{fbhp} \quad \ldots\ldots(4.6) \]

Where \( p_{fnp} \) is the final net pressure.

In this equation, the inclusion of the final net treating pressure \( (p_{fnp}) \) is done in order to emphasize the reduction of the flowing bottom whole pressure \( (p_{fbhp}) \) as well drawdown takes place (see schematic Fig 4.13). This view is shared by Sookprasong (2010), whose proposed proppant stress equation however uses reservoir pressure, \( p \) instead of \( (p_{fnp}) \) as shown above.

Practically, the minimum horizontal stress is obtained from the pressure decline characteristics of the LOTs and XLOTs described in Chapter 3. From the equation above, Jones and Britt (2009) highlight the following:

1. As the reservoir pressure reduces, the stress on the proppant decreases.
2. As well drawdown occurs, \( p_{fbhp} \) reduces at the wellbore and the stress on the proppant will increase

The pressure in the fracture is higher with increasing distance from the wellbore. The maximum stress a proppant would be subjected to would normally take place at the initial stages of production, during or immediately after fracturing fluid clean-up when hydrocarbon starts to flow, especially in gas wells. Quality assurance is sometimes done using proppant crushing tests (API RP 56 1983) (Jones and Britt, 2009).
4.3.4 – Proppant Embedment Pressure

Embedment pressure is defined by Rixe et. al (1963) as “a measure of the maximum pressure required to embed a steel ball to a given depth in rock. This gives a direct indication of the resistance of the formation to embedment by a propping material and the effect of the rock on proppant deformation”. It is a kind of indentation test and is a measure of the rock strength. A test procedure for determining the embedment pressure is described by Howard and Fast (1970). A steel ball point 0.05 inches in diameter (which simulates the proppant) is attached to the upper platen of a hydraulic testing machine which moves, and loads the rock specimen (3.5 inches diameter) hydraulically (see Fig 4.14). Where possible, the rock core should be obtained from the well to be hydraulically fractured. The steel ball point is embedded to a depth of 0.0125 in and a strain recorder is used to observe the results. The load at the target embedment, \( W_p \), is recorded and at least two more indentations are made on the test specimen, about 0.5 inches apart. Finally, the diameter of the indentation, \( d_i \), is measured under a microscope and the embedment pressure is calculated as:

\[
\text{Embedment pressure (psi)} = \frac{4W_p}{\pi d_i^2}
\] .................................(4.7)

The embedment pressures for 22 formations are shown in table 4.5. McGlothlin and Huitt (1959) present another method of calculating rock embedment strength. They suggest crushing proppants between plates with similar penetration hardness (Howard and Fast, 1970).

An obvious drawback in the test described by Howard and Fast, is the inherent assumption that the steel ball point has the same physical characteristics as the proppant. Steel varies significantly from sand, ceramic, nutshells e.t.c.
4.3.5 – Fracture capacity (conductivity)

As earlier stated, the fracture conductivity is a measure of proppant performance. Proppant selection is deemed successful only when it can achieve substantial fracture conductivity. The fracture flow capacity (conductivity) depends on the fracture width, proppant distribution and proppant concentration. The post-fracture width is controlled by proppant size used for stimulation, while proppant concentration is controlled by spacers. Proppant distribution is not an easily controlled parameter (Howard and Fast, 1970).

Rixe et al (1963), describe a test procedure for determining fracture conductivity of a given proppant. The proppant is placed between two rock cores and subjected to similar overburden pressure and temperature. Pictures of proppants in conductivity cells are shown in Fig 4.7. The rock cores (3.5 inches diameter and 2 inches long) are mounted in steel cups with a low temperature melting point alloy, in such a way that 0.25 inches of the smooth core face extends above the top edge of the cup. This is shown pictorially in Fig 4.15 and schematically in fig 4.16. A hole is drilled axially in the upper half of the core to intersect a shallow hole in the center of the lower half, as shown in the aforementioned figures. The overburden stress is simulated using a hydraulic ram, see setup shown in Fig 4.17 and Fig 4.18. The temperature is controlled by placing the rock cores in a heated box. Fracture capacity is determined by allowing nitrogen gas to flow from the hole in the upper half of the core through the simulated propped fracture (Howard and Fast, 1970). The flow capacity is calculated based on Darcy’s law and considering radial gas flow. To take into account the time effect, the test is carried out for a 30-day period with flow rates recorded at 7-day intervals. It has been discovered that 30 days is the time required for the fracture to stabilize and hence, for long-term fracture capacity to be stimulated (Fixe et al, 1963). The use of the conductivity and embedment pressure for proppant selection is described in section 4.3.6
Although the test described above has been used over the years for successful fracturing treatments, it has certain drawbacks. Firstly, the field conditions of proppants are not dry as assumed by the test. The drawbacks of the test are made more evident by considering several other factors that affect the effectiveness of fracture conductivity:

1. Production and migration of proppant fines
2. Proppant flowback
3. Proppant embedment
4. Multiphase flow
5. Non-Darcy flow considerations

**Production and migration of fines**

Fines are the little particles that break off the surface of proppants as they are subjected to closure stress. These fines have a significant impact on reduction of fracture conductivity. Several investigators like Coulter et al (1972) show that the presence of just 5% fines can reduce conductivity by as much as 62%. These results have been corroborated by Lacy et al (1997) showing a 54% reduction with 5% fines present. The decrease in conductivity is made worse when the fines migrate to the wellbore. Standard crushing tests like API RP 56, API RP 58, API RP 60 and ISO 13503-1 make use of dry proppants subjected to the closure stress for only 2 minutes which doesn’t simulate the field wet, hot condition. Modified crush test procedures have been proposed by Freeman et al (2009) and Diep (2009) to better simulate field conditions (see Fig. 4.19 and Fig 4.20). In Fig 4.20, the resin coating prevents the migration of fines in the curable resin coated sand (CRCS) proppant (Terracina et al, 2010).
**Proppant flowback**

Proppant flowback is the movement (flow) of proppants back to the wellbore (see Fig 4.21). The higher the pump velocity, the more the chance of flowback occurring. Proppant flowback and pack re-arrangement is the main cause of well production decline, equipment damage and well lock-down for repairs. It reduces conductivity at the wellbore and decreases connectvity to the reservoir (Terracina et al, 2010). The use of resin coated proppants has helped to reduce the flowback tendency of proppants, this is shown in the highly magnified SEM photograph of a CRCS grain-to grain bonding in Fig 4.22.

**Proppant Embedment**

This causes a loss in conductivity due to the interaction between the formation and the proppant at the face of the fracture. It is considered a problem in partially consolidated to unconsolidated formations, but it also occurs a little in hard rock (Jones and Britt, 2009). Fig 4.23 demonstrates how proppant embedment can reduce post-fracture width and hence conductivity. As shown, more than 1/3 of the grain diameter is lost due to embedment. Another result of embedment is the creation of formation fines through “spalling” (see Fig. 4.24), which can then migrate and further reduce conductivity (Terracina et. al, 2010). The advantage of embedment is that it would help prevent flowback.

**Non-Darcy Flow considerations**

When the flow is high (turbulent), Darcy’s equation becomes inadequate. Non-Darcy flow reduces the permeability of the proppant pack (Jones and Britt, 2009).
4.3.6 – Proppant selection - Method of Rixe et al(1963)

Rixe et al (1963) proposed the following procedure for proppant selection.

**Step 1:** Determination of the fracture flow capacity needed to achieve desired level of well production. The required fracture flow capacity depends on the formation flow capacity and the fracture penetration into the reservoir. Fig 4.25 depicts the relationship between the ratio of fracture to formation capacity (also called contrast) to the increase in production ratio, while considering fracture penetration. These plots are based on data that assume Darcy flow of homogeneous fluid through the formation. From the plot it is seen that the higher the formation flow capacity, then relatively higher fracture flow capacity is required to achieve maximum production (i.e high fracture to formation flow contrast). Quantitatively, a contrast of 10 and a fracture penetration of 30% a 4-fold increase in production is expected, but if the contrast is increased to 100, it would yield a 6-fold increase in production. Also, from the plot it is observed that the deeper the fractures, the more significant the contrast effect on production increase.

**Step 2:** Determination of embedment pressure. This could be done as described in section 4.3.4.

**Step 3:** Selection of type of propping agent required by using charts such as the one shown in Fig 4.26. This chart was prepared from correlating results from embedment pressure tests and fracture capacity tests on different propping agents and various formations. The maximum fracture capacity for a given embedment pressure and propping agent must lie in the region below the curve of the particular propping agent.

These curves vary with depth in which proppant performance was evaluated. For the figure shown, it was at 7000 ft.
Step 4: Selection of the size and concentration of the propping agents from the embedment pressure, using charts in Fig 4.27 to Fig 4.29.

Example Calculation

Well depth ................................................................. 7000ft

Formation ................................................................. Tensleep, Wyoming

Embedment Pressure (table 4.5) ................................. 196,600psi

Planned increase in well productivity.......................... 6-fold

Formation capacity ................................................. 160 md-ft

Planned fracture penetration................................. 30 percent of drainage radius

1. From Fig 4.25, it is seen that to effect a 6-fold increase for a 30% fracture penetration, then a fracture to formation contrast of 50 is required.

2. Hence, the fracture capacity required = 160 X 50 = 8000md-ft.

3. Plotting the fracture capacity and embedment pressure on Fig 4.26, shows that it is above the curve for sand, hence sand is not suitable. However it is below, the nut shells straight line plot, so it is adequate.

4. Using the plot in Fig 4.28 for rounded nut shells, we conclude the selection as follows: A fracture capacity of 8000md-ft can be achieved in the Tensleep, Wyoming formation with an embedment pressure of 196,600 psi using a -12 to 20 mesh rounded nutshell at 0.024 lb/ft concentration.

Notice that in Fig 4.27, the chart for natural sand. At low embedment pressure (50 psi) the smaller size sand proppants, type C (-20 to 40 mesh) clearly has a lower fracturing capacity than the larger
size proppants type B (-10 to 20). However as the embedment pressure increases to about 200 to 250 thousand psi, both curves B and C gradually come together almost intersecting. This means that at high embedment pressure, the fracture capacity (conductivity) of both large and small size proppants is nearly equal. This does not occur in other materials like nutshell and aluminium (see Fig 4.28 and 4.29) which all have fracture capacity proportional to proppant size. Thus, it is most likely caused by a material property of natural sand. It is proposed here that it occurs as a result of the tendency of large sand particles to crush at high pressures. Another possibility could be that at high pressures, there is greater proppant embedment in large size proppants (see fig 4.23), hence, their fracture conductivity reduces bringing it closer to conductivity values of small size proppants.

4.4 – Case study example of typical Hydraulic Fracturing Stimulation (Fontaine et al, 2008)

4.4.1 - Introduction

This section is on the stimulation treatment of a Marcellus well in Potter county, Pennsylvania operated by Guardian Exploration LLC. It was presented in a paper by Fontaine et al (2008). This Case study is chosen because it describes in detail how a typical fracturing design is routinely adjusted to fit observed field conditions. Also, the treatment was done by using ideas that were successful in other shale plays like Barnett shale of Fort Worth basin and Fayetteville of Arkansas. This is however rarely encountered as shales differ greatly with location. The well log is shown in Fig 4.30. The Marcellus was at a depth of 5220 to 5310 ft. The well casing had a 4-4.5 inch outside diameter, weighing 11ppf and rated at 6700 psi working pressure. With regards to stratigraphy, the Marcellus shale was underlain by the Onondanga lime which proved to be a good lower barrier to fracture growth but there was no significant upper barrier.
4.4.2 - Preliminary slickwater fracture design

The preliminary fracture design is shown in table 4.6. The design consisted of pumping 545,000 gallons of 5 PPT (parts per trillion) slickwater base fluid at a rate of 50BPM (barrels per minute). 100,000 pounds of 80/100 mesh proppant, 350,000 pounds of 30/50 mesh proppant and 137,500 pounds of 20/40 mesh proppant were to be placed at concentrations ranging from 0.5 to 3 PPA (pounds proppant added). Wellbore sweeps were pumped at intervals of proppant usage, in order to reduce near wellbore proppant settlement. Drilling fluid sweeps are fluids of adequate density and viscosity, used to clean wellbore of cuttings (in this case remnant proppants). They erode the top of proppant dunes that are deposited near the wellbore and prevent them from building up.

Additives used include the following: friction reducing polyacrylamide, bacteriacides and a non-foaming microemulsion surfactant. To achieve 50 BPM, a 6500 HHP (hydraulic horsepower) was used, maintaining a pressure gradient of about 1 psi/ft.

4.4.3 - Starting treatment

At the start of treatment, the well perforation was done at the lowest portion of the organic rich section of the formation. Acid was not used initially, to reduce the risk of formation damage. An initial downhole rate of approximately 25 BPM with a corresponding surface treating pressure of over 5000 psi as seen in Fig 4.31. After about 45 minutes, it was observed that the bottom hole pressure (BHP) had increased to about 8000 psi, thus suggesting a pressure gradient of 1.5 psi/ft which was too high. This showed that the perforations were not transmitting the fluid, thus pumping was stopped. Then spot acid was used over the perforations to breakdown the formation further. A steady downhole rate of 42 BPM and 6200-6300 psi BHP was later achieved after acid treatment. Proppant slugs (80/100 mesh sand at 0.1 ppa concentration) were pumped to further reduce the treating pressure to 5500 psi (since 6400 was maximum allowable) and stabilize the
downhole rate to the target 50 BPM (see Fig 4.32). It was believed that the initial high bottom hole pressure was because of high perforation friction and the possible existence of multiple competing natural fractures, thus causing near well bore tortuosity (see Fig.4.33).

### 4.4.4 – Proppant selection and placement

The slickwater base fluid used was a thin fluid that exhibited apparent viscosity only when pumped. This thinness helped in reducing fluid friction, but had the drawback of limited proppant transport. At 50BPM, its apparent viscosity was equivalent to 30 centipoise guar gel viscosity. The proppant treatment involved the placement of 587,500 pounds of proppants with 545,000 gallons of fluid. The percentage of proppant composition was 17% 80/100 mesh, 60% 30/50 mesh and 23% 20/40 mesh. As stated previously, to prevent build-up of proppants around the wellbore, well sweeps were used (Fig 4.34). According to WoodWorth (2007), small volume sweeps such as the ones used in this treatment are the most effective. The sweep highlighted in figure 4.34 is highlighted in Figure 4.4f. Looking closely, we can see that the pressure was gradually increasing from 5000 psi to 5600 psi because of proppant build-up. The introduction of the sweeps helped to mitigate this increase. The proppant placement started with the smaller size (80/100) proppants before finally the largest size (20/40) as seen in the schedule of table 4.6. The effect of increasing proppant size and concentration on the net pressure is shown in Fig 4.35.

### 4.4.5 - Finishing treatment

Fig 4.36 shows the pressure plot for finishing treatment. When proppant addition is stopped, there is a loss of hydrostatic pressure in the wellbore that increases the surface treating pressure. This pressure increase is 795 psi. It was ensured that the wellbore rating of 6700 psi was not exceeded during the flush of the treatment. In Fig 4.37, the portion of the plot highlighted with the box occurs immediately after shutting down the pumps. It is normally called “water hammer” and
shows that there is a good wellbore to formation existing, a rough measure of conductivity. This was made possible because of previous steps to minimize near wellbore tortuosity using acid treatment.
Chapter 5 – CONCLUSION/RECOMMENDATIONS

Hydraulic fracturing is a very sophisticated operation and so far has been carried out via technical expertise, sound experience and the rule-of-thumb approach. Fracture mechanics itself is a complex field and require lots of mathematical approximations to estimate fracture geometry.

During formation testing, pressure transient tests are conducted to calculate formation permeability, fracture conductivity and fracture half-length estimates. However, as stated in the classical Lee and Holditch paper the permeability is not obtained directly from pressure tests even with the modified Millheim Cinchowicz method. It is obtained as an estimate from other drawdown tests. This trend prevails up till date with permeability estimates obtained as external data from pressure tests. It is recommended that a unified system of testing be designed, were permeability can be obtained simultaneously from pressure tests as well as the other core parameters: conductivity and half-length.

Mini-fracs also known as Extended leak-off tests (XLOTs) have been shown to give better estimates of the minimum horizontal stress than the leak-off tests (LOTs) because of the additional pressurization cycles. Experience has shown that taking the value of the minimum horizontal stress in the first cycle were the LOTs terminate is overly conservative. A better estimate is in the second or third cycle, which is contained in the XLOTs. However due to the relative ease of conducting the LOT, it is more popular in the industry. This practice does not give the best estimate of the minimum horizontal stress and should be discouraged.

The major difference in the two variants of XLOTs, which are Pump-in/shut-in and Pump-in/flowback tests and the actual XLOTs is that in the shut-in and flowback tests the planned fracturing fluid is not used. The pump-in/shut-in have been found to be useful to estimate closure pressure but in shales which take too much time to close, the flowback test is preferred. However,
research by Raen show that the flowback test underestimates the closure pressure. It has been established that the Step-rate test (SRT) which gives the fracture extension pressure is a good upper bound for the closure pressure. Thus, further work can be done on development of standard charts that could mark the upper bound (with SRTs) and lower bound (with flowback tests) of closure pressure in order to bound the validity of the results from shut-in tests or XLOTs.

The early 2D models: PKN and KGD are useful simple approximations to determining the average fracture width while assuming constant fracture height. To account for complexity in fracture growth, the pseudo 3D models and fully 3D models have been proposed. The drawbacks of the 3D model is its reliance on the accuracy of many input parameters in order to make useful predictions. An error in just one parameter would significantly affect 3D model based simulation results. A solution to this could be to build a database from results of past successful hydraulic fracturing stimulation. From this database an operator would have a profound idea of shale characteristics at depth in a region even before beginning the formation testing or fracture modeling. To create this solution would require the co-operation of fracturing companies that have been in the business for a long time.

It is a widely known fact that during actual stimulation, the observed net pressure is different from the predicted bottom hole pressure (BHTP). Thus, effort has been made to use the pressure observed as stimulation progresses to change model inputs, so as to have a better estimate of fracture dimensions. This process termed net pressure matching is ubiquitous in the industry. There has however been no effort to quantitatively explain the influence that changes in friction pressure has on the observed net pressure. Further research could be done on this area, with a view to bridging the distance between the net observed pressure and model predicted bottom hole pressure. A standard guide for the complementary use of both the direct mapping techniques
(tiltmeter and microseismic mapping) and net pressure matching is needed. This would remove the “black box” status that most oil and gas professionals have attached to this process.

Fracturing fluid and additive selection is a highly proprietary procedure. Some suggested methods of standardizing the fluid selection process is in appendix B. Proppant selection has been an area of interest to oil and gas industry professionals over the years. The theory behind proppant stress determination is in section 4.3.3 of the thesis. It is recommended that the closure pressure should be obtained from SRTs, which give upper bound estimates. If these are used for proppant stress determination they would give values of proppant stress that are reasonably conservative.

Standard crushing tests like American Petroleum Institute (API) RP 56, API RP 58, API RP 60 and ISO 13503-1 make use of dry proppants subjected to the closure stress for only 2 minutes which doesn’t simulate the field wet, hot condition. Modified crush test procedures have been proposed by Freeman et al (2009) and Diep (2009) to better simulate field conditions. These test procedures should be improved, standardized and adopted by the API, in order to improve proppant selection.

Most fracture capacity tests make use of nitrogen gas. Natural gas is made up mainly of methane, hydrogen, carbon dioxide, nitrogen, hydrogen sulphide and other impurities. More investigation into the use of an adequate mixture of carbon dioxide and nitrogen for the embedment pressure test is recommended (eliminating methane and other inflammable components). The aim would be to better simulate the fluid flow of natural gas. This hybrid mixture would improve assessment of fracture conductivity and make for better proppant selection.
## Table 1.1 – Types of Completions and conditions for selection (After Azar and Samuel, 2007)

<table>
<thead>
<tr>
<th>Completion Type</th>
<th>Conditions</th>
</tr>
</thead>
</table>
| Vertical well Natural completion | - High permeability ($K_h \geq 10$ md for oil, $\geq 1$ md for gas) open hole stable formation (no movement or spalling)  
- No bottom or edge water drives  
- Low $K_v$ ($K_v < K_h$) (or deviated wells not considered possible)  
- No fracture planned/possible, no limits on surface/reservoir access  
- Laminations not frequent. |
| Vertical well Open hole Frac planned | - No limits on permeability  
- Stable formation (no movement or spalling)  
- No bottom or edge water drive control needed low $K_v$ ($K_v < 0.1K_h$) (or deviated wells not considered/possible)  
- No limits on surface/reservoir access  
- Multiple frac not planned  
- Laminations not frequent in zones not fractured  
- Bottom/edge water not penetrated by frac. |
| Vertical well Cased hole Frac or frac pack planned | - No limits on permeability  
- Cased hole 190° perforating and screenless pack frac for sand control  
- Very high production rates possible  
- Gravel packs only where sand control needed. |
| Vertical well Open hole Gravel pack | - High permeability ($K_h \geq 10$ md for oil, $\geq 1$ md for gas)  
- Laminations not frequent” (h < 2 ft)  
- No bottom or edge water control needed low $K_v$ ($K_v < 0.5K_h$) (or deviated wells not considered/possible)  
- No limits on surface/reservoir access  
- Gravel packs only where sand control needed. |
| Vertical well Cased hole Gravel pack | - High permeability ($K_h \geq 10$ md for oil, $K_h \geq 1$ md for gas)  
- Laminations not “frequent” (h < 2 ft)  
- Limited bottom or edge water control needed  
- Low $K_v$ ($K_v < 0.5K_h$) or deviated wells not considered possible)  
- No limits on surface/reservoir access  
- Gravel packs only where sand control needed. |
| Deviated path approach Vertical well in pay | • Surface/reservoir access limited  
| • Deviated wellbore in pay not practical/possible  
| • Laminted zones  
| • Zones with barriers.  |
| Multi-lateral well Vertical or horizontal | • Surface/reservoir access limited  
| • Thick layered pay zones  
| • Multiple well types needed  
| • Compartmentalized reservoirs  
| • Wellbore placed mostly for water control; wellbore placement for sweep/drainage  
| • Very limited need for reentry (unless mechanical system used)  
| • No pressure isolation needed.  |
| Horizontal well Open hole | • $K_v > 0.5K_o$ or plan to frac open hole  
| • No interbed barriers  
| • No sealing lamination unless plan to frac  
| • Stable formation (no movement or spalling or plan to gravel pack)  
| • Good bottom water control possible  
| • Surface/reservoir access restricted.  |
| Horizontal well liner | • $K_v > 0.5K_o$ (unless plan to frac)  
| • No interbed barriers  
| • No sealing laminations, (unless plan to frac)  
| • Some spalling control  
| • No sand control problems  
| • No multiple fracs planned (unless isolation packers set)  
| • Limited bottom water drive control  
| • Production logs/isolation not needed.  |
| Horizontal well cased | • $K_v > 0.5K_o$ (unless plan to frac)  
| • No interbed barriers  
| • No sealing laminations (unless plan to frac)  
| • No vugs or natural fractures (severe cement damage), unless plan to frac).  |
Table 1.2 - API designated classes of Portland cement (After Azar and Samuel, 2007)

<table>
<thead>
<tr>
<th>Class Type</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class A:</td>
<td>For use from surface to 6,000 ft (1,830 m) depth, when special properties are not required.</td>
</tr>
<tr>
<td>Class B:</td>
<td>For use from surface to 6,000 ft (1,830 m) depth, when conditions require moderate to high sulfate resistance.</td>
</tr>
<tr>
<td>Class C:</td>
<td>For use from surface to 6,000 ft (1,830 m) depth, when conditions require high early strength.</td>
</tr>
<tr>
<td>Class D:</td>
<td>For use from 6,000 ft to 10,000 ft depth (1,830 m to 3,050 m), under conditions of high temperatures and pressures.</td>
</tr>
<tr>
<td>Class E:</td>
<td>For use from 10,000 ft to 14,000 ft depth (3,050 m to 4,270 m), under conditions of high temperature and pressures.</td>
</tr>
<tr>
<td>Class F:</td>
<td>For use from 10,000 ft to 16,000 ft depth (3,050 m to 4,880 m), under conditions of extremely high temperatures and pressures.</td>
</tr>
<tr>
<td>Class G:</td>
<td>Intended for use as a basic cement from surface to 8,000 ft (2,440 m) depth. Can be used with accelerators and retarders to cover a wide range of well depths and temperatures.</td>
</tr>
<tr>
<td>Class H:</td>
<td>A basic cement for use from surface to 8,000 ft (2,440 m) depth as manufactured. Can be used with accelerators and retarders to cover a wider range of well depths and temperatures.</td>
</tr>
<tr>
<td>Class J:</td>
<td>Intended for use as manufactured from 12,000 ft to 16,000 ft (3,600 m to 4,880 m) depth under conditions of extremely high temperatures and pressures. It can be used with accelerators and retarders to cover a range of well depths and temperatures.</td>
</tr>
<tr>
<td>Core recovery types</td>
<td>Description</td>
</tr>
<tr>
<td>-------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Conventional (Plug) Analysis</td>
<td>It is the most common method used. Small plug-type samples are obtained at selected core intervals. Normally 1-1.5 inches in length.</td>
</tr>
<tr>
<td>Whole core (Full diameter or continuous)</td>
<td>A full diameter core is obtained (see Fig 2.20). It is useful in those formations that the small samples (like in the plug method) are not representative.</td>
</tr>
<tr>
<td>Horizontal coring</td>
<td>Conventional cores up to 90 ft in length are cut in horizontal wells using downhole motors.</td>
</tr>
<tr>
<td>Sidewall coring</td>
<td>Small cores drilled, punched or recovered from projectiles fired into the wall of the drill hole. It provides samples from specific locations of the logged well after hole has been drilled. The use of the Rotary tool prevents damage to hard formations, that can be cause using percussion sidewall coring. Sidewall values have a large margin of error in hard, low permeability formations and unconsolidated sands</td>
</tr>
<tr>
<td>Improved</td>
<td>This method has evolved from normal use of only</td>
</tr>
<tr>
<td>Method</td>
<td>Description</td>
</tr>
<tr>
<td>------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Rubber Sleeve Core</td>
<td>Rubber sleeve for recovery to a combination of non-intrusive bits, full-closure core catchers and sleeve inner barrels. Rock samples are obtained by: 1. Punching when cores are completely unconsolidated or 2. Initially freezing the rock prior to removal of the confining sleeve, then core drilling with liquid nitrogen.</td>
</tr>
<tr>
<td>Sponge Coring</td>
<td>It is an economical method for assessing residual oil saturation and less expensive than pressure coring.</td>
</tr>
<tr>
<td>Gel Coring</td>
<td>Displaceable formation specific gel is used in the core barrel. This minimizes flushing during coring, fluid migration during retrieval and fluid loss at the surface. It also provides mechanical support for the core.</td>
</tr>
<tr>
<td>Oriented Core</td>
<td>It provides orientation to core to determine direction and degree of formation dip, tilt of fractures, and directional permeability.</td>
</tr>
</tbody>
</table>
Table 2.2 – Permeability of well samples, showing effect of confining pressure (After Al-Multhana et al. 2008)

<table>
<thead>
<tr>
<th>Sample ID</th>
<th>Pressure &gt; 200 psig</th>
<th>Pressure &lt; 200 psig</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Dry Weight (gm)</td>
<td>Permeability (md)</td>
</tr>
<tr>
<td>18</td>
<td>182.20</td>
<td>367</td>
</tr>
<tr>
<td>19</td>
<td>183.59</td>
<td>771</td>
</tr>
<tr>
<td>22</td>
<td>198.89</td>
<td>179</td>
</tr>
<tr>
<td>25</td>
<td>211.75</td>
<td>0.16</td>
</tr>
<tr>
<td>26</td>
<td>208.24</td>
<td>0.09</td>
</tr>
<tr>
<td>27</td>
<td>205.25</td>
<td>0.09</td>
</tr>
<tr>
<td>178</td>
<td>187.44</td>
<td>1329</td>
</tr>
<tr>
<td>179</td>
<td>186.37</td>
<td>1060</td>
</tr>
<tr>
<td>180</td>
<td>183.60</td>
<td>1714</td>
</tr>
</tbody>
</table>

Table 3.1 – Plot types used for analysis, After Lee et al, 2004.

<table>
<thead>
<tr>
<th>Purpose</th>
<th>Operation</th>
<th>Quantities</th>
<th>Scales</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overview, Quality</td>
<td>Display</td>
<td>Pressure and Volume vs Time</td>
<td>Linear-Linear</td>
<td>Both pressure and volume are displayed as a function of time</td>
</tr>
<tr>
<td>Fracture initiation</td>
<td>Pump-in, fluctuating</td>
<td>Pressure vs</td>
<td>Linear-Linear</td>
<td>Fracture extends</td>
</tr>
</tbody>
</table>
In all the tests above, the plots show a change in system compliance as the fracture is opened or
closed, characterized as a change in slope in the pressure vs time or pressure vs volume data (Lee et al 2004)

Table 3.2 – Classification of pressure tests performed at the casing shoe: PITs (After Addis et al, 1998)

<table>
<thead>
<tr>
<th>Pressure Integrity Test Name</th>
<th>Test Description (c.f. Figs. 1 &amp; 2)</th>
<th>Usefulness in Stress Estimation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Integrity Test (FIT):</td>
<td>The test is run until planned maximum mud weight is reached but does not reach $p_{fo}$.</td>
<td>Little</td>
</tr>
<tr>
<td>Leak-Off Test (LOT):</td>
<td>The test is run beyond $p_{fo}$, and a proper leak-off pressure is determined.</td>
<td>Poor</td>
</tr>
<tr>
<td>Leak-Off Test (LOT):</td>
<td>The test is run to beyond $p_{fo}$ but shut-in before any apparent breakdown and the pressure decline is monitored.</td>
<td>Poor</td>
</tr>
<tr>
<td>Leak Off Test (LOT):</td>
<td>The test is run to Point A, and formation breakdown pressure is determined additionally the pressure decline is monitored.</td>
<td>Moderate</td>
</tr>
<tr>
<td>ELOT (XLOT):</td>
<td>The well is shut-in at Point A, and the pressure decline is monitored. A second and perhaps a third repressurization and shut-in are performed.</td>
<td>Good</td>
</tr>
</tbody>
</table>

Table 3.3 – Shut-in pressures, minimum and maximum stress gradients from ELOTs performed on the North West Shelf, Australia (After Addis et al, 1998)

<table>
<thead>
<tr>
<th>Well</th>
<th>Depth AMSL (m)</th>
<th>Shut-In pressure from ELOT (MPa)</th>
<th>Minimum Stress Gradient ($p_s$) (kPa/m)</th>
<th>Maximum Stress Gradient ($p_m$) (Eqn.8) (kPa/m)</th>
<th>$p_{sh}/p_s$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1069.3</td>
<td>16.201</td>
<td>15.15</td>
<td>19.55</td>
<td>1.29</td>
</tr>
<tr>
<td>2</td>
<td>1046.3</td>
<td>16.202</td>
<td>15.38</td>
<td>20.07</td>
<td>1.30</td>
</tr>
<tr>
<td>3</td>
<td>1584.0</td>
<td>20.630</td>
<td>13.12</td>
<td>15.58</td>
<td>1.18</td>
</tr>
<tr>
<td>4</td>
<td>1021.0</td>
<td>16.011</td>
<td>15.61</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>5</td>
<td>2372.9</td>
<td>35.667</td>
<td>14.92</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>6</td>
<td>565.0</td>
<td>6.908</td>
<td>12.21</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
Table 3.4 – Shut-in pressures, minimum and maximum stress gradients from ELOTs performed on
the Norwegian North Sea (After Addis et al, 1998)

<table>
<thead>
<tr>
<th>Well</th>
<th>Depth from ELOT (m)</th>
<th>Shut-In pressure (MPa)</th>
<th>Minimum Stress Gradient ($\sigma_s$) (kPa/m)</th>
<th>Maximum Stress Gradient ($\sigma_u$) (Eqn.8) (kPa/m)</th>
<th>$\rho_s/\rho_a$</th>
<th>Vertical Stress Gradient ($\rho_v$) (kPa/m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>30/9-B15</td>
<td>955</td>
<td>16.46</td>
<td>17.23</td>
<td>-</td>
<td>-</td>
<td>17.8</td>
</tr>
<tr>
<td>30/9-13s</td>
<td>1106</td>
<td>18.40</td>
<td>16.64</td>
<td>-</td>
<td>-</td>
<td>18.0</td>
</tr>
<tr>
<td>30/6-23</td>
<td>927</td>
<td>15.26</td>
<td>16.46</td>
<td>21.56-21.84</td>
<td>1.31-1.33</td>
<td>17.2</td>
</tr>
<tr>
<td>30/6-11</td>
<td>2081</td>
<td>34.31</td>
<td>16.49</td>
<td>19.62-20.68</td>
<td>1.19-1.21</td>
<td>19.4</td>
</tr>
<tr>
<td>30/6-C07</td>
<td>2500</td>
<td>41.84</td>
<td>16.74</td>
<td>-</td>
<td>-</td>
<td>20.0</td>
</tr>
<tr>
<td>30/6-C06</td>
<td>957</td>
<td>15.77</td>
<td>16.48</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
Table 3.5 – Oil reservoir Data for 3D Model Application (After Settari and Cleary, 1984)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\phi$</td>
<td>0.15</td>
</tr>
<tr>
<td>$k_x$, md</td>
<td>485</td>
</tr>
<tr>
<td>$k_y$, md</td>
<td>485</td>
</tr>
<tr>
<td>$H_r$, ft</td>
<td>100</td>
</tr>
<tr>
<td>$\rho_{w, \text{sat}}$, psia</td>
<td>2,710</td>
</tr>
<tr>
<td>Depth, ft</td>
<td>5,900</td>
</tr>
<tr>
<td>$T_{w, \text{sat}}$, °F</td>
<td>154</td>
</tr>
<tr>
<td>$C_R$, psia$^{-1}$</td>
<td>$4 \times 10^6$</td>
</tr>
<tr>
<td>$\lambda_w$, Btu/ft°F/D</td>
<td>39</td>
</tr>
<tr>
<td>$(\rho C_p)_{\text{sat}}$, Btu/ft°F</td>
<td>37</td>
</tr>
<tr>
<td>$C_{v0}$, Btu/lbm°F</td>
<td>0.5</td>
</tr>
<tr>
<td>$C_{wv}$, Btu/lbm°F</td>
<td>1.0</td>
</tr>
<tr>
<td>$C_{T_0}$, °F$^{-1}$</td>
<td>0.000365</td>
</tr>
<tr>
<td>$C_{T_w}$, °F$^{-1}$</td>
<td>0.00021</td>
</tr>
<tr>
<td>$h_{wi}$, Btu/°F-sq ft-D</td>
<td>12</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>$S_w$</th>
<th>$k_{rw}$</th>
<th>$k_{ro}$</th>
<th>$P_c$ (psia)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.2</td>
<td>0</td>
<td>1.0</td>
<td>59.0</td>
</tr>
<tr>
<td>0.3</td>
<td>0</td>
<td>1.0</td>
<td>56.0</td>
</tr>
<tr>
<td>0.4</td>
<td>0</td>
<td>1.0</td>
<td>51.0</td>
</tr>
<tr>
<td>0.5</td>
<td>0.0515</td>
<td>0.319</td>
<td>28.0</td>
</tr>
<tr>
<td>0.6</td>
<td>0.098</td>
<td>0.088</td>
<td>23.0</td>
</tr>
<tr>
<td>0.7</td>
<td>0.139</td>
<td>0.031</td>
<td>20.0</td>
</tr>
<tr>
<td>0.8</td>
<td>0.17</td>
<td>0.0515</td>
<td>19.0</td>
</tr>
<tr>
<td>0.9</td>
<td>0.20</td>
<td>0</td>
<td>18.0</td>
</tr>
<tr>
<td>1.0</td>
<td>0.515</td>
<td>0</td>
<td>17.0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>$T$ (°F)</th>
<th>$\mu_o$ (cp)</th>
<th>$\mu_w$ (cp)</th>
</tr>
</thead>
<tbody>
<tr>
<td>60.0</td>
<td>14.0</td>
<td>1.0</td>
</tr>
<tr>
<td>80.0</td>
<td>9.7</td>
<td>1.0</td>
</tr>
<tr>
<td>100.0</td>
<td>7.8</td>
<td>0.88</td>
</tr>
<tr>
<td>120.0</td>
<td>6.0</td>
<td>0.88</td>
</tr>
<tr>
<td>140.0</td>
<td>4.8</td>
<td>0.48</td>
</tr>
<tr>
<td>160.0</td>
<td>3.7</td>
<td>0.41</td>
</tr>
<tr>
<td>180.0</td>
<td>3.0</td>
<td>0.35</td>
</tr>
<tr>
<td>200.0</td>
<td>2.6</td>
<td>0.32</td>
</tr>
</tbody>
</table>

Grid dimensions ($h$): $\Delta x=20, 30, 40, 60, 100, 150, 200, 500, 1,000, 2,500, 5,000$, $\Delta y=2, 5, 10, 50, 200$. 

141
Table 3.6 – Pumping Data for 3D Model Application (After Settari and Cleary, 1984)

<table>
<thead>
<tr>
<th>Schedule</th>
<th></th>
<th>16</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pumping rate, bbl/month</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proppant</td>
<td>Q</td>
<td>c</td>
</tr>
<tr>
<td></td>
<td>(bbl)</td>
<td>(lbm/gal slurry)</td>
</tr>
<tr>
<td>Pad</td>
<td>122</td>
<td>—</td>
</tr>
<tr>
<td>100-mesh sand</td>
<td>324</td>
<td>1.647</td>
</tr>
<tr>
<td>10/20-mesh sand</td>
<td>264</td>
<td>1.047</td>
</tr>
<tr>
<td>10/20-mesh sand</td>
<td>368</td>
<td>1.4</td>
</tr>
<tr>
<td>10/20-mesh sand</td>
<td>40</td>
<td>2.64</td>
</tr>
<tr>
<td>10/20-mesh sand</td>
<td>56</td>
<td>3.38</td>
</tr>
<tr>
<td>10/20-mesh sand</td>
<td>156</td>
<td>4.14</td>
</tr>
</tbody>
</table>

For GCD Only

<table>
<thead>
<tr>
<th>For GCD Only</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Tensile strength, psia</td>
<td>500</td>
</tr>
<tr>
<td>Surface energy, lbm/sec²</td>
<td>6,000</td>
</tr>
</tbody>
</table>

For PKN and 3D Only

| Average $K'$ | 0.24 |
| Average $n = m$ | 0.37 |

Subdivision of proppant transport grid: 1:4

<table>
<thead>
<tr>
<th>$a_{eff}$ (psia)</th>
<th>$k_f$ (md)</th>
<th>$A_f(a_{eff})/A_f(0)$</th>
</tr>
</thead>
<tbody>
<tr>
<td>—</td>
<td>500,000</td>
<td>1.0</td>
</tr>
<tr>
<td>2,000</td>
<td>400,000</td>
<td>0.9</td>
</tr>
<tr>
<td>6,000</td>
<td>120,000</td>
<td>0.85</td>
</tr>
<tr>
<td>8,000</td>
<td>40,000</td>
<td>0.82</td>
</tr>
<tr>
<td>10,000</td>
<td>20,000</td>
<td>0.8</td>
</tr>
</tbody>
</table>

Effective height for productivity = 120 ft, centered around pay.
Table 3.7 – Fluid Treatment Data for 3D Model Application (After Settari and Cleary, 1984)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\sigma_e$, psia</td>
<td>3.027</td>
</tr>
<tr>
<td>$E$, psia</td>
<td>$4 \times 10^6$</td>
</tr>
<tr>
<td>$\nu$</td>
<td>0.27</td>
</tr>
<tr>
<td>$C_{II}$, ft/min</td>
<td>0.0015</td>
</tr>
<tr>
<td>$u_s$, ft/min</td>
<td>0.00002</td>
</tr>
</tbody>
</table>

**Fluid Rheology**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Mainly Affects</th>
<th>During</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Permeability</td>
<td>Slope decline</td>
<td>Breakdown injection</td>
</tr>
<tr>
<td>Wallbuilding Coefficient</td>
<td>Slope decline</td>
<td>Minifrac tests</td>
</tr>
<tr>
<td>Pressure-dependent leakoff</td>
<td>Slope decline</td>
<td>Prop frac</td>
</tr>
<tr>
<td>Fracture Complexity</td>
<td>Level</td>
<td>All injections</td>
</tr>
<tr>
<td>Stress Contrast (Pay-barrier)</td>
<td>Level</td>
<td>All injections</td>
</tr>
</tbody>
</table>
### Tip Effects

<table>
<thead>
<tr>
<th>Level</th>
<th>All injections</th>
</tr>
</thead>
</table>

### Proppant Drag

<table>
<thead>
<tr>
<th>Level</th>
<th>All injections</th>
</tr>
</thead>
</table>

### Compliance change during tip screen-out (TSO)

<table>
<thead>
<tr>
<th>Level</th>
<th>TSO</th>
</tr>
</thead>
</table>

### Composite Layering

<table>
<thead>
<tr>
<th>Geometry</th>
<th>All injections</th>
</tr>
</thead>
</table>

### Width decoupling

<table>
<thead>
<tr>
<th>Geometry</th>
<th>All injections</th>
</tr>
</thead>
</table>

---

**Table 4.1 – Fracturing Fluids and General Conditions for Use (After Xiong et al, 1996).**

<table>
<thead>
<tr>
<th>Fluid Base</th>
<th>Fluid type</th>
<th>Main Composition</th>
<th>Generally Used For</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water-based</td>
<td>Linear fluids</td>
<td>Gelled water, HPG, HEC, CMHPG, CMHEC, etc</td>
<td>Short fractures, low temperatures</td>
</tr>
<tr>
<td></td>
<td>Crosslinked fluids</td>
<td>Crosslinker + HPG, HEC or CMHEC, etc</td>
<td>Long fractures, high temperatures</td>
</tr>
<tr>
<td>Oil-based</td>
<td>Linear fluids</td>
<td>Oil, Gelled oil</td>
<td>Water sensitive formations, long fractures</td>
</tr>
<tr>
<td>Water external polymerulsion</td>
<td>Emulsifier +Oil + Water</td>
<td>Good for fluid loss control</td>
<td></td>
</tr>
<tr>
<td>Foam-based</td>
<td>Acid-based foam</td>
<td>Acid+foamer+ N2</td>
<td>Low pressures, water sensitive formations</td>
</tr>
<tr>
<td></td>
<td>Water-based foam</td>
<td>Water + Foamer+CO2 or N2</td>
<td>Low pressure formations</td>
</tr>
<tr>
<td>Alcohol based foam</td>
<td>Methanol + Foamer + N2</td>
<td>Low pressure formations with water blocking problems</td>
<td></td>
</tr>
<tr>
<td>---------------------</td>
<td>------------------------</td>
<td>------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Alcohol based Linear system</td>
<td>Gelled water + alcohol</td>
<td>Removal of water blocking problems</td>
<td></td>
</tr>
<tr>
<td>Crosslinked system</td>
<td>Crosslinked system + alcohol</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4.2- Suggested Fracture Treatment Types for Different Formations (After Kennedy et al, 2012)

<table>
<thead>
<tr>
<th>FracFluid type</th>
<th>Formation</th>
<th>Pump rate</th>
<th>Conductivity</th>
<th>Play Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slickwater/linear gel</td>
<td>Dry Gas or Low liquid</td>
<td>High 100+ BPM</td>
<td>Infinite to gas</td>
<td>Barnett, Marcellus, Fayetteville</td>
</tr>
<tr>
<td>Hybrid Frac</td>
<td>Gas condensate</td>
<td>Low 60 to 80 BPM</td>
<td>More conductive frac</td>
<td>Eagle, Ford, Utica</td>
</tr>
<tr>
<td>Cross linked Frac</td>
<td>Oil bearing</td>
<td>Low 40 to 60 BPM</td>
<td>Highly conductive frac</td>
<td>Bakka, Niobara, Eagle, Ford</td>
</tr>
</tbody>
</table>
Table 4.3 – Effect of different size proppant on a fracture geometry and fracture characteristics (After Cohen et al, 2013)

<table>
<thead>
<tr>
<th>Sand mesh size</th>
<th>Proppant placement for slickwater treatment (1cp)</th>
<th>Propped length (ft)</th>
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Table 4.4 – Pumping schedule with several proppant sizes (After Cohen et al, 2013)

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Table 4.5 – Embedment Pressure Values for various formations (After Howard and Fast, 1970)

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Table 4.6 – Preliminary slickwater fracture design (After Fontaine et al, 2008)

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FIGURES

Figure 1.1 – Shale distribution in the United States (After Arthur et al., 2009)

Modified from Schlumberger, 2005
Figure 1.2 – Process Flow Diagram for a Hydraulic Fracture Treatment (After Arthur et al, 2009)
Figure 1.3– Water storage – “frac” tanks - After Arthur et al (2009)

Figure 6  Water Storage – “Frac” Tanks (Fayetteville Shale)
Figure 1.4 – Picture of frac head  (After Travelin Terriers, 2013  www.travelinterriers.com)
Figure 1.5 – Hydraulic fracturing site (After Hibbeler and Rae, 2005)
Figure 1.6 – Double well casing to protect groundwater sources (After Marathon Oil Corp, 2012)

Figure 1.7 – Horizontal Drilling in Shale Strata (After King et al, 2010)
Figure 1.8 – Drilling Rig Components (After King et al, 2012)

Drilling Rig Components

1. **Crown Block and Water Table**
2. **Catline Boom and Hoist Line**
3. **Drilling Line**
4. **Monkeyboard**
5. **Traveling Block**
6. **Top Drive**
7. **Mast**
8. **Drill Pipe**
9. **Doghouse**
10. **Blowout Preventer**
11. **Water Tank**
12. **Electric Cable Tray**
13. **Engine Generator Sets**
14. **Fuel Tanks**
15. **Electric Control House**
16. **Mud Pump**
17. **Bulk Mud Components Storage**
18. **Mud Pits**
19. **Reserve Pits**
20. **Mud Gas Separator**
21. **Shale Shaker**
22. **Choke Manifold**
23. **Pipe Ramp**
24. **Pipe Racks**
25. **Accumulator**

From the OSHA website

Equipment used in drilling
Figure 1.9 – Vertical and directional wells (After Azar and Samuel, 2007)

Figure 1.10 – Different types of drill bits (After Devereux, 2012)
Figure 1.11 – Basic elements to drill a well (After Azar and Samuel, 2007)
Figure 1.12 – Section of rotary drilling rig (After Azar and Samuel, 2007)
Figure 1.13 – Block and Tackle Hoisting system (After Azar and Samuel, 2007)
Figure 1.14 – Fluid circulation system (After Azar and Samuel, 2007)
Figure 1.15 – Rotary system of drilling rig (After Azar and Samuel, 2007)

1. Rotary table - drive and bushings
2. Swivel
3. Rotary (kelly) hose
4. Drill string
5. Kelly
Figure 1.16 – Floor of a drilling rig showing rotary table (After Devereux, 2012)
Figure 1.17 – Typical blowout preventer (BOP) arrangement (After Azar and Samuel, 2007)
Figure 1.18 – Picture of BOP (After Devereux, 2012)
Figure 1.19 – Blowout preventer positioned on a well (After Devereux, 2012)
Figure 1.20 – Horizontal drilling by jetting (After Devereux, 2012)

1. Wash away a pocket by jetting
2. Start to drill, bit follows pocket direction
3. Well deviated in pocket direction
Figure 1.21 – Horizontal drilling by using a whipstock (After Devereux, 2012)

1. Run the whipstock with the BHA.
2. Drill ahead, the whipstock forces the bit to the side.
3. Pull out of the hole, remove the whipstock, and run back in to drill.
Figure 1.22 – Horizontal drilling via steerable motor (After Devereux, 2012)
Figure 1.23 – Optimization of casing string along depth (After Azar and Samuel, 2007)
Figure 1.24 – A conductor pipe (After Azar and Samuel, 2007)
Figure 2.1 – Guide lines on PIT graph (After Postler et al, 1997)

Figure 2.2 – Schematic of PIT equipment (After Postler et al, 1997)
Figure 2.3 - Description of dimensionless fracture conductivity (After Jones and Britt, 2009)

- Fracture half-length, $x_f$, ft
- Formation permeability, $k$, md
- Fracture flow capacity, $k_f w$, md-ft

$$F_{CD} = \frac{k_f w}{k \cdot x_f}$$
Figure 2.4– Three conventional test configurations for determination of vertical permeability (After Ehlig-Economides et al, 2006)
Figure 2.5 – Horner plot, pressure buildup test data from a South Texas gas well (After Lee and Holditch, 1979)
Figure 2.6 – Millheim-Cinchowicz plot, pressure buildup test data from South Texas gas well (After Lee and Holditch, 1979)

Figure 2.7 – Synthetic drawdown curves for modified M-C method, constant rate case (After Lee and Holditch, 1979)
Figure 2.8 – Modified M-C plots, field buildup tests (After Lee and Holditch, 1979)

Figure 2.9 – Extrapolation of linear region, modified M-C method (After Lee and Holditch, 1979)
Figure 2.10— Typical partial perforation pressure buildup response (After Barnum et al, 1990)
Figure 2.11 – Pressure buildup showing effect of wellbore damage and after-production (After Howard and Fast, 1970)

Figure 2.12 – Bottomhole pressure versus buildup time (After Gladfelter et al, 1955)
Figure 2.13— Drawdown plot of dimensionless real gas potential versus log of dimensionless time (After Vairogos et al, 1973)

1 REAL GAS, S = +1
2 REAL GAS, S = 0
3 REAL GAS, S = -3
4 IDEAL GAS, CONSTANT k, S = 0

P_i = 7000
q_{sc} = 1000
Figure 2.14- Vertical permeability correlation chart (After Barnum et al, 1990)
Figure 2.15 – Nomogram for end of first straight-line region (After Barnum et al, 1990)
Figure 2.16 – Effect of fracture capacity on post-fracturing conductivity (After Howard and Fast, 1970)
Figure 2.17– Effect of in-situ stress contrast on fracture containment (After Heydarabaradi et al, 2010)

Figure 2.18– Containment of a fracture opposite overburden (After Heydarabaradi et al, 2010)

a. Constant Stress gradient
b. Overstressed burden
Figure 2.19– Well blowout (After “Lucasher Gusher”
http://www.sjgs.com/gushers.html#spindletop, 2013)
Figure 2.20 - Full closure core catcher (After Unalmiser and Funk, 1998)
Figure 2.21 – Composite photograph of core from various depositional environments (After Keelan, 1982)
Figure 2.22 – SEM photograph of Illite clay in pore space. (After Keelan, 1982)

Figure 2.23 – NMR relaxation and distribution (After Unalmiser and Funk, 1998)
Figure 2.24 – CT scan 1 (After Al-Muthana et al, 2008)

Figure 2.25 – CT scan 2 (After Al-Muthana et al, 2008)

Figure 2.26 – CT scan 3 (After Al-Muthana et al, 2008)
Figure 2.27 – Effect of calibration on grain density (After Al-Multhana et al, 2008)

Figure 2.28 – Effect of drying time on porosity and permeability (After Al-Multhana et al, 2008)
Figure 2.29 – Schematic diagram of shear and compressional wave propagation (After Timur A. Turk)

Figure 2.30– Sonic log versus depth (After Glover, 1986)
Figure 2.31 – Pre- and post-fracture temperature logs showing thermal conductivity effects (After Jones and Britt, 2009)
Figure 2.32– A vertical well in the Woodford shale showing bedding planes and high angle fractures using an LWD electrical image (After Quinn et al, 2008)

The red bars in the rose plot (circle) show fracture strikes while the green bars indicate azimuth of sedimentary rock (Quinn et al, 2008).
Figure 2.33– LWD electrical images obtained from horizontal well in Barnett shale. (After Quinn et al, 2008)

The left image shows intersecting and non-intersecting natural fractures as well as drilling-induced tensile fractures on the top and bottom of the well. The right image shows drilling-induced tensile fractures clearly visible along the bottom of the wellbore. This is less clear at the top of the well. Also, there are many small, healed natural fractures intersecting the wellbore that have been opened in the tensile section of the wellbore (compare static normalized image and dynamic normalized image). This fractures were caused by drilling (Quinn et al, 2008).
Figure 2.34 – Correlation between Total Organic content (TOC) log and Gamma Ray (GR) (After Orlandi et al, 2011)
Figure 3.1  – Normal leakoff plot of log Pressure Derivative versus time log-log plot (After Barree et al, 2009)

Fig. 3 — Normal leakoff log-log plot.
Figure 3.2 – Tip extension plot of Pressure derivative versus time (After Barree et al, 2009)

Fig. 18 — Tip extension log-log plot.
Figure 3.3 – Pressure and Flow data from two cycles of Mini-frac tests in an offshore location at the Timor sea (After Zoback, 2012)

In tests like this one, there is no significant difference between the shut-in pressure and closure pressures on each of the two cycles. The pumping pressure is only about 100 psi higher than the shut-in pressure. Also, the test records show that the surface pressure (which is roughly the downhole pressure plus the hydrostatic pressure from the surface to measurement depth) varies by less than 2% (Zoback, 2012).
Figure 3.4 – Pressure-time records of two tests in shaly dolomite near Anna, Ohio. (After Zoback and Haimson, 1982)

<table>
<thead>
<tr>
<th>Test #37</th>
<th>Test #39</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_c$</td>
<td>$P_c$</td>
</tr>
<tr>
<td>$P_s(\text{hor})$</td>
<td>$P_s(\text{vert})$</td>
</tr>
<tr>
<td>$P_s(\text{hor})$</td>
<td>$P_s(\text{hor})$</td>
</tr>
<tr>
<td>Time (sec)</td>
<td>Time (sec)</td>
</tr>
</tbody>
</table>

Test #37 represents initiation and extension of a horizontal bedding plane fracture. In test #39 a vertical fracture initiated at the well bore and turned into a horizontal plane. This interpretation was confirmed by an impression packer (Haimson, 182b)
Figure 3.5– Results from tests in a well in South Carolina (After Zoback and Haimson, 1982)

This shows change in shut-in pressure as hydraulic fractures are propagated (Haimson and Zoback, 1982)
Figure 3.6– Double tangent method plot I (After Amadei and Stephansson, 1997)

Figure 3.7– Double tangent method plot II (After Amadei and Stephansson, 1997)
Figure 3.8 – Double tangent method plot III (After Amadei and Stephansson, 1997)

Figure 3.9 – Muskat Method/Exponential pressure decay (After Amadei and Stephansson, 1997)
Figure 3.10 - McLennan and Roegiers inflection method (After Amadei and Stephansson, 1997)

Figure 3.11 – Horner plot (After Jones and Britt, 2007)
Figure 3.12 - Method of Turnbridge/Bilinear pressure decay rate method (After Amadei and Stephansson, 1997)
Figure 3.13 - Pump-in flowback closure stress test (After Jones and Britt, 2009)

Pump-off (leads to curve reversal)
Figure 3.14 – Step-rate test (SRT) result, showing additional derivative plot below (After Jones and Britt, 2009)
Figure 3.15 – Step rate test (SRT) at different depths (After Zoback, 2012)
Figure 3.16 – A schematic mini-frac test /XLOT showing pressure as a function of volume, or time (at constant flowrate) (After Zoback, 2010)

LT = Limit test
LOP = Leak-off point
FIT = Formation integrity test
FBP = Formation breakdown pressure
FPP = Fracture propagation pressure
ISIP = Instantaneous shut-in pressure
FCP = Fracture closure pressure
Figure 3.17 – Extended pressurization cycles of XLOTs (After Lee et al, 2004)

Credit for this reference material goes to the LOT committee of the API RP 66 work group on annular flow prevention.

Leak off test Nomenclature and Definition
LP – Limit Pressure
FIP – Fracture Initiation Pressure
SPP – Stop Pump Pressure
UFP – Unstable Fracture Pressure
FPP – Fracture Propagation Pressure
ISIP – Instantaneous Shut In Pressure
FCP – Fracture Closure Pressure
FRP – Fracture Reopening Pressure
Figure 3.18 – A standard LOT pressure versus volume plot showing leak-off pressure (After Addis et al, 1998)

Figure 3.19 – An idealized pressurization cycle from a PIT (After Addis et al, 1998)
Figure 3.20 – An Ideal example of a pressure record from a hydraulic fracturing stress test showing the features sought in an ELOT (After Addis et al, 1998)

Figure 3.21 – Pressure records for the six ELOTS performed in the North West Shelf, Australia (After Addis et al, 1998)
Figure 3.22 – A comparison of leak-off pressures from standard LOTs (+) with minimum stress estimates from ELOTs for the North West Shelf of Australia (After Addis et al, 1998)
Figure 3.23 – Leak-off pressures from standard LOTs (+) from vertical wells plotted with minimum stress estimates from E(X)LOTS in the Oseberg Field, Norwegian sea. (After Addis et al, 1998)

Figure 3.24 – Leak-off pressures from standard LOTs (+) from vertical and inclined wells plotted with minimum stress estimates from E(X)LOTS in the Oseberg Field, Norwegian sea. (After Addis et al, 1998)
Figure 3.25 – Pressure Dependent Leakoff G-function plot (After Barree et al, 2009)

Figure 3.26 – Tip extension G-function plot (After Barree et al, 2009)
Figure 3.27 - Storage G-function plot (After Barree et al, 2009)
Figure 3.28 – Howard and Fast assumed fracture geometry (After Holditch et al, 1987)
Figure 3.29 – Perkins-Kern-Nordgren’s assumed fracture geometry (After Holditch et al, 1987)
Figure 3.30– Vertical and Horizontal plane strain condition, with PKN geometry (showing wellbore) below (After Valko and Economides, 1995)
Figure 3.31 – Geertsma-de Klerk-Daneshy (KGD) assumed fracture geometry (After Holditch et al, 1987)

Figure 3.32– The KGD Geometry showing wellbore - (After Valko and Economides, 1995)
Figure 3.33- Radial fracture assumed geometry (After Holditch et al, 1987)
Figure 3.34 – Transverse vertical fractures from a horizontal well (After Valko and Economides, 1995)
Figure 3.35 – Turning fractures in a horizontal well from longitudinal initiation to the transverse direction (After Valko and Economides, 1995)

Figure 3.36 – Vertical Fracture initiated from an arbitrarily oriented horizontal well at an angle, $\alpha$ from the minimum horizontal stress (After Valko and Economides, 1995)
Figure 3.37 – Vertical fracture profile through a three-layer formation with dissimilar properties (After Valko and Economides, 1995)

Figure 3.38 – Fracture height growth with associated width reduction due to adjoining layer of high stiffness (After Valko and Economides, 1995)
Figure 3.39 – A T-shape fracture (proppant screenout) (After Valko and Economides, 1995)
Figure 3.40 – Cumulative gas volume produced with time for different fracture half-lengths (After Hareland and Rampersad, 1994)

![Cumulative gas volume produced with time for different fracture half-lengths](image)

Figure 3.41 – Gas production decline with time for different fracture half-length (After Hareland and Rampersad, 1994)

![Gas production decline with time for different fracture half-length](image)
Figure. 3.42 – Schematic of a Pseudo 3D Hydraulic Fracturing model (After Xiaowei Weng, 1992)

Figure. 3.43 – Schematic of the 2D flow in the fracture (After Xiaowei Weng, 1992)
Figure 3.44 – Approximation of the outer flow field at the element of interest by a local radial flow (After Xiaowei Weng, 1992)

Figure 3.45 – Comparison of fracture shapes predicted by different models (After Xiaowei Weng, 1992)
Figure 3.46 – Example of StimPlan Output (After Barree et al, 2009)

Figure 3.47 – Configuration of a fully 3D physical system (After Settari and Cleary, 1984)
Figure 3.48 – Fracture shapes for different degrees of containment (After Settari and Cleary, 1984)

Figure 3.49 – Comparison of computed fracturing pressures for different fracture geometries (After Settari and Cleary, 1984)
Figure 3.50 – An example of Fracpro-PT Output (After Barree et al, 2009)
Figure 3.51 – Fracture Diagnostic techniques (After Cipolla and Wright, 2002)
Figure. 3.52 – Principle of tiltmeter fracturing mapping (After Cipolla and Wright, 2002)

Figure. 3.53 – Surface tiltmeter in a site at Western Missouri (After Jones and Britt)
Figure 3.54—Surface deformation for hydraulic fractures of different orientations at a depth of 3000 ft (After Wright et al, 1998)

Dip = 0°
Maximum Displacement: 0.0020 inches

Dip = 90°
Maximum Displacement: 0.00026 inches

Dip = 80°
Maximum Displacement: 0.00045 inches
Figure 3.55 – Picture of tiltmeter used to predict eruptions on Mount Loa, Hawaii (After Wikipedia, 2013)
The fracture mapping resolution depends on offset well location and distance relative to fracture dimensions (Wright et al, 1999)
Figure 3.57– Theoretical downhole tiltmeter pattern of deformation (After Jones and Britt, 2009)
Figure 3.58 – Principle of microseismic fracture mapping (After Cipolla and Wright, 2002)

Receiver detects ground motion from microseism

Elastic waves emitted

Tip region

Leakoff region

Figure 3.59 – Microseismic event location from Fisher (2005) (After Jones and Britt, 2009)
Figure 3.60 – Multiple component geophone array with P and S wave arrivals (After Jones and Britt, 2009)
Figure 3.61– Example of a Hodogram
(www.Crewes.org/Researchlinks/Explorerprogram/Hodogram/Hodogram.html)
Figure 3.62 – Unconventional gas well history matching (After Britt et al, 2010)
Figure 3.63 – Nolte-Smith interpretation guide from Britt et al (1994) (After Jones and Britt, 2009)

I. Contained Height—Unrestricted Extension
II. Stable Growth/Natural Fracture Opening
III. Restricted Extension (Screenout)
IV. Unstable Height Growth
Figure 3.64 – Width decoupling due to containment caused by layers (After Barree et al, 2009)

Figure. 3.65– Composite layering and width decoupling Weijers et al, 2005
The first figure (left) shows the typical mechanism of fracture growth confinement due to increased closure stress in the layers above and below the target zone. The middle figure is a mechanism based on the 2D KGD model, and would result in perfect confinement at the layer interface. The last figure (right) shows composite layering effect due to partial deboning of the layer interfaces (Weijers et al, 2005).

Figure. 3.66 – Observed net pressure (black) and match with model net pressure (green) (After Weijers et al, 2005)

Note: The model net pressure response from both the calibrated and uncalibrated models are almost identical.
In top section, estimated fracture for net pressure history match using typical model assumptions is shown. In bottom section, matching of both net pressure history and directly observed fracture geometry using additional containment effects such as composite layering is shown (After Weijers et al, 2005)
Figure 4.1 – Composition of a Proppant Laden fracture Fluid (After Arthur et al, 2009)

Source: Compiled from Data collected at a Fayetteville Shale Fracture Stimulation by ALL Consulting 2008.

Figure 4.2- Schematic diagram showing effect of adding fluid-loss additives (After Hawsey et al, 1961)
Figure 4.3- Plot of fluid loss versus time (After Hawsey et al., 1961)

\[ m = 0.5 \]
\[ V_{sp} = 4.0 \text{ cc} \]
Figure 4.4- Fracture area and injection rate versus fluid loss coefficient (After Hawsey et al, 1961)
Figure 4.5- Correction factor for Spurt loss using nomograph (After Hawsey et al, 1961)
Figure 4.6 – Animation of Hydraulic fracturing (After Marathon Oil Corp, 2013)

Figure 4.7 – Cross-sectional photos of three proppants under stress in the conductivity cell (courtesy of Stim-Lab consortium) (After Palisch et al, 2010)
Figure 4.8 – Effect of proppant settling velocities (After Bivins et al, 2005)
https://slb.com/~media/Files/resources/oilfield_review/ors05/sum05/03_new_fibers.pdf

Effects of proppant-settling velocities. High settling velocities cause proppant to concentrate at the bottom of a fracture before it closes (top). Low settling velocities promote complete and uniform distribution of proppant throughout the fracture (bottom).
Figure 4.9 – Production rate for different proppant sizes - After Cohen et al (2013)

Figure 4.10 – Cumulative production for different proppant size (After Cohen et al , 2013)
Figure 4.11- Krumbein and Sloss chart of sphericity and roundness (After Kullman (2011) South Dakota School of Mines)
Figure 4.12- Comparison of commercial proppants on the Krumbein and Sloss chart (After Kullman (2011) South Dakota School of Mines)
Figure 4.13 – A schematic of pressure during shut-in and flow (After Sookprasong, 2010)

Figure 4.14- Embedment pressure test technique (After Howard and Fast, 1970)
Figure 4.15 – Picture of mounted core assembly for fracture capacity test (After Rixe et al, 1963)

Figure 4.16 – Diagram of mounted core assembly for fracture capacity test (After Howard and Fast, 1970)
Figure 4.17 – Test apparatus for fracture flow capacity test (After Rixe et al., 1963)
Figure 4.18 – Nitrogen flow system for measuring fracture flow capacity (After Rixe et al, 1963)
Figure 4.19 – Scanning Electron Microscope (SEM) photograph (404X) of 40/80 mesh lightweight ceramic proppant fines after a wet, hot crush test at 10,000 psi. (After Terracina et al, 2010)

Figure 4.20 – Enveloping of proppant fines with resin coating as seen by a CAT scan of CRCS wet, hot crush test at 10,000 psi. Grain to grain bonding with resin is also shown. (After Terracina et al, 2010)
Figure 4.21 – Proppant flowback from the fracture into the wellbore can occur with uncoated proppant or procured RCS (After Terracina et al, 2010)

Figure 4.22 – SEM photo (651X) of CRCS grain to grain bonding that eliminates proppant flowback by forming a consolidated proppant pack in the fracture (After Terracina et al, 2010)
Figure 4.23– Proppant embedment into the fracture face reduces fracture width and conductivity. After Terracina et al (2010)

Figure 4.24 –SEM photograph (514X) of formation fines spalling (in red circle) due to grain embedment (After Terracina et al, 2010)
Figure 4.25 – Approximate production increase due to fracturing (After Rixe et al, 1963)

*Penetration = horizontal fracture radius or depth of penetration of one of a pair of vertical fractures at 180 deg, expressed as percent of drainage radius.

- $Q_F$ = production after fracturing, BOPD
- $Q_o$ = production before fracturing, BOPD
- $H_e$ = net pay thickness, ft
- $K_e = \text{effective horizontal permeability, md}$
- $K_FH_F = \text{effective fracture capacity, md-ft}$
Figure 4.26 – Generalized selection chart for maximum fracture capacity obtainable at a depth of 7000 ft (After Rixe et al, 1963)
Figure 4.27 – Propping agent selection curve for sand at well depth of 7000ft (After Rixe et al., 1963)

Well Depth, 7,000 Ft
A – 0.6 lb/sq ft, 1 monolayer; B – 0.3 lb/sq ft, 1 monolayer; C – 0.2 lb/sq ft, 1 monolayer.
Figure 4.28 – Propping agent selection curve for rounded nutshells at well depth of 7000ft (After Rixe et al, 1963)

Well Depth, 7,000 Ft
A – 0.033 lb/sq ft, 0.1 monolayer; B – 0.024 lb/sq ft, 0.1 monolayer.
Figure 4.29 – Propping agent selection curve for rounded nutshells at well depth of 7000ft (After Rixe et al, 1963)

Well Depth, 7,000 Ft
1 – 0.07 lb/sq ft, 0.1 monolayer; 2 – 0.1 lb/sq ft, 0.25 monolayer.
Figure 4.30 – Potter County, PA Marcellus Well log (After Fontaine et al, 2008)

Marcellus Shale @ 5220 to 5310 ft depth
Onandaga Lime (good barrier to fracture)
Figure 4.31- Treatment initiation: The effect of acid upon wellbore entry (After Fontaine et al., 2008)

Figure 4.32- The use and effect of proppant slugs (After Fontaine et al., 2008)

Proppant slugs are additives added to stabilize bottomhole pressure, by reducing effects, if any of fractures near the wellbore.
Figure 4.33- Illustration of near wellbore complexity (tortuosity) versus simplicity. (After Fontaine et al, 2008)

Figure 4.34- Use of wellbore sweeps between proppant stages (After Fontaine et al, 2008)
Figure 4.35 - The effect of a sweep (After Fontaine et al, 2008)

Figure 4.36 - Effects of Proppant Concentration and Mesh size on Net Pressure (After Fontaine et al, 2008)
Figure 4.37- Finishing the treatment (After Fontaine et al, 2008)
APPENDIX

Principle of Fracturing Fluid Selection Using Fuzzy Logic (Xiong et al, 1996)

Table A1 gives a list of fracturing fluids and common conditions for their use.

Table A1

<table>
<thead>
<tr>
<th>Fluid Base</th>
<th>Fluid Type</th>
<th>Main Composition</th>
<th>Generally Used for</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water-based</td>
<td>Linear fluids</td>
<td>Gelled water, HPG, HEC, CMHPG, CMHEC, etc.</td>
<td>Short fractures, low temperatures</td>
</tr>
<tr>
<td></td>
<td>Crosslinked fluids</td>
<td>Crosslinker + HPG, HEC, or CMHEC, etc.</td>
<td>Long fractures, high temperatures</td>
</tr>
<tr>
<td>Oil-based</td>
<td>Linear fluids</td>
<td>Oil, Gelled oil</td>
<td>Water sensitive formations, short fractures</td>
</tr>
<tr>
<td></td>
<td>Crosslinked fluids</td>
<td>Crosslinker + Oil</td>
<td>Water sensitive formations, long fractures</td>
</tr>
<tr>
<td></td>
<td>Water external polyemulsion</td>
<td>Emulsifier + Oil + Water</td>
<td>Good for fluid-loss control</td>
</tr>
<tr>
<td>Foam-based</td>
<td>Acid-based foam</td>
<td>Acid + Foamer + N₂</td>
<td>Low pressures, water sensitive formations</td>
</tr>
<tr>
<td></td>
<td>Water-based foam</td>
<td>Water + Foamer + CO₂ or N₂</td>
<td>Low pressure formations</td>
</tr>
<tr>
<td></td>
<td>Alcohol-based foam</td>
<td>Methanol + Foamer + N₂</td>
<td>Low pressure formations with water blocking problems</td>
</tr>
<tr>
<td>Alcohol-based</td>
<td>Linear system</td>
<td>Gelled water + Alcohol</td>
<td>Removal of water blocks</td>
</tr>
<tr>
<td></td>
<td>Crosslinked system</td>
<td>Crosslinked system + Alcohol</td>
<td></td>
</tr>
</tbody>
</table>

In the fuzzy logic system proposed by Xiong et al, 1996, the system first determines base fluid, viscosifying method and energization method. Next, a choice is made of the 3 to 5 best combinations of the possible fluids. Thereafter the system determines polymer type and loading, crosslinker, gas type and other additives. It simultaneously checks the compatibility of the fluid and additives with formation fluids. The possible combinations of viscosifying method, base fluid and energizer is shown in table A2.
Table A2 – The Possible combinations of base fluid, viscosifying method and energization method

<table>
<thead>
<tr>
<th>Viscosifying</th>
<th>Base Fluid</th>
<th>Energization</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Crosslinked</td>
<td>Linear</td>
</tr>
<tr>
<td>Crosslinked</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Linear</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Polymulsion</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Base Fluid</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Water</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Oil</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Alcohol</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Energization</td>
<td>Foamed</td>
<td>X</td>
</tr>
<tr>
<td>Energized</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Normal</td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>

In the tables A3 to A9, the importance of the fuzzy variables to the decisions of the system is given as a weighting factor. These factors are extracted from expertise (experience). They can be adjusted for different situations in a fuzzy system. For instance, to rank the viscosification methods for a particular formation case, the parameters considered are: temperature, fracture length, height and treatment size (see fig A1). The membership functions are translated to weighting factors and used to rank best choice of viscosification method. The rules that guide the ranking of best choice are in figs. A13 to A18. The fuzzy system is a considerably subjective process because of its reliance of weighting factors borne out of human experience/judgement.
Fig A1 – Procedure to select fluids and additives
Viscosification method

Crosslinked fluids are usually used in the higher temperature formations and/or in large size treatments. Linear fluids are preferred for low temperature and medium or small size treatments. Polyemulsions are used when moderate viscosity is needed without the need for high temperature stability.

Table A3 – Parameters for Crosslinked, Polyemulsion and Linear fluids

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Unit</th>
<th>Weighting Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature</td>
<td>T</td>
<td>°F</td>
<td>0.4</td>
</tr>
<tr>
<td>Fracture Height</td>
<td>H</td>
<td>ft</td>
<td>0.2</td>
</tr>
<tr>
<td>Fracture Length</td>
<td>Lf</td>
<td>ft</td>
<td>0.2</td>
</tr>
<tr>
<td>Young's Modulus</td>
<td>E</td>
<td>psi</td>
<td>0.1</td>
</tr>
<tr>
<td>Fluid Complexity</td>
<td>Cx</td>
<td>-</td>
<td>0.1</td>
</tr>
</tbody>
</table>

Base fluids

Table A4 - Parameters for Water, Oil and Alcohol fluids

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Unit</th>
<th>Weighting Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water Sensitivity</td>
<td>Ws</td>
<td>-</td>
<td>0.35</td>
</tr>
<tr>
<td>Fracture Length</td>
<td>Lf</td>
<td>ft</td>
<td>0.10</td>
</tr>
<tr>
<td>Formation Temperature</td>
<td>T</td>
<td>°F</td>
<td>0.15</td>
</tr>
<tr>
<td>Cost and Safety</td>
<td>C</td>
<td>-</td>
<td>0.20</td>
</tr>
<tr>
<td>Formation Depth</td>
<td>D</td>
<td>ft</td>
<td>0.10</td>
</tr>
<tr>
<td>Formation Fluid Type</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fluid Complexity</td>
<td>Cx</td>
<td>-</td>
<td>0.1</td>
</tr>
</tbody>
</table>

*: no oil base fluids for gas formations.
Table A5 – Parameters for foam/energized/normal fluids

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Unit</th>
<th>Weighting Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure Gradient</td>
<td>$p_g$</td>
<td>psi/ft</td>
<td>0.4</td>
</tr>
<tr>
<td>Formation Temperature</td>
<td>$T$</td>
<td>°F</td>
<td>0.15</td>
</tr>
<tr>
<td>Fracture Length</td>
<td>$L_f$</td>
<td>ft</td>
<td>0.20</td>
</tr>
<tr>
<td>Formation Depth</td>
<td>$D$</td>
<td>ft</td>
<td>0.15</td>
</tr>
<tr>
<td>Fluid Complexity</td>
<td>$C_x$</td>
<td>-</td>
<td>0.1</td>
</tr>
</tbody>
</table>

Polymer Type

There are different polymer types available for water base fluids in the industry. Guar and HPG are popular. HEC is selected when fluid cleanup is important. Cost, residue and fracture length are also important.

Table A6 – Parameters for Polymer Type selection

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Unit</th>
<th>Weighting Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Temperature</td>
<td>$T$</td>
<td>°F</td>
<td>0.45</td>
</tr>
<tr>
<td>Cost Index</td>
<td>$C$</td>
<td>-</td>
<td>0.35</td>
</tr>
<tr>
<td>Permeability</td>
<td>$k$</td>
<td>md</td>
<td>0.20</td>
</tr>
<tr>
<td>Base Fluid</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Polymer concentration

This varies with treatment size and formation temperature (see table A-7 below)

Table A7 – Parameters for Polymer Loading

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Unit</th>
<th>Weighting Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Treatment Size</td>
<td>S</td>
<td>ft²</td>
<td>0.5</td>
</tr>
<tr>
<td>Formation Temperature</td>
<td>T</td>
<td>°F</td>
<td>0.5</td>
</tr>
<tr>
<td>Polymer Type</td>
<td>-</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Gas Quality**: For foams, usually 70 to 75% quality is used depending on the pressure treatment size.

For energized fluid, the gas quality is about 15%.

Gas type: For foamed or energized fluid, N2 and CO2 are not compatible with oil based fluids. N2 is normally not used in high temperature deep formations. The parameters to choose gas types are shown in table A8 below:

Table A8 – Parameters for gas type (N2 and CO2)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Unit</th>
<th>Weighting Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Temperature</td>
<td>T</td>
<td>°F</td>
<td>0.35</td>
</tr>
<tr>
<td>Formation Depth</td>
<td>D</td>
<td>ft</td>
<td>0.35</td>
</tr>
<tr>
<td>Fracture Length</td>
<td>Lf</td>
<td>ft</td>
<td>0.25</td>
</tr>
<tr>
<td>Cost Index</td>
<td>C</td>
<td>-</td>
<td>0.05</td>
</tr>
</tbody>
</table>
Crosslinker: The three commonly used crosslinkers are: borate, zirconium and titanium. Their selection depends on the parameters shown in table A9.

Table A9 – Parameters for crosslinker

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Unit</th>
<th>Weighting Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Temperature</td>
<td>T</td>
<td>°F</td>
<td>0.45</td>
</tr>
<tr>
<td>Fracture Size</td>
<td>S</td>
<td>ft²</td>
<td>0.25</td>
</tr>
<tr>
<td>Clean Break</td>
<td>Cb</td>
<td>-</td>
<td>0.20</td>
</tr>
<tr>
<td>Cost Index</td>
<td>C</td>
<td>-</td>
<td>0.10</td>
</tr>
</tbody>
</table>

Examples

In the table below are two example situations to apply the fuzzy logic system:

Table A-10

<table>
<thead>
<tr>
<th>Example No.</th>
<th>1</th>
<th>2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure (psi)</td>
<td>6,200</td>
<td>1,080</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>345</td>
<td>120</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>400</td>
<td>1,000</td>
</tr>
<tr>
<td>Frac Height (ft)</td>
<td>300</td>
<td>100</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td>13,000</td>
<td>4,500</td>
</tr>
<tr>
<td>Permeability (md)</td>
<td>0.1</td>
<td>0.01</td>
</tr>
<tr>
<td>Water Sensitivity</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Formation Fluid</td>
<td>gas</td>
<td>gas</td>
</tr>
</tbody>
</table>

No 1: In this case, we have a deep and thick formation containing gas. It has a high temperature and normal pressure. The formation is also not water sensitive. Due to the above observations of
formation depth and temperature, a suitable choice proposed by Xiong et al (1996) is 60 lbm
crosslinked CMHPG water gel (see table A-11 below)

Table A-11 – Recommendations for example no 1

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Fluid 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rank</td>
<td>1</td>
</tr>
<tr>
<td>Viscosifying Method</td>
<td>crosslinked</td>
</tr>
<tr>
<td>Energizing Method</td>
<td>normal</td>
</tr>
<tr>
<td>Base Fluid</td>
<td>water</td>
</tr>
<tr>
<td>Polymer Type</td>
<td>CMHPG/HPG</td>
</tr>
<tr>
<td>Polymer Loading</td>
<td>60 lb/1000gal</td>
</tr>
<tr>
<td>Gas Type</td>
<td>NA</td>
</tr>
<tr>
<td>Gas Quantity</td>
<td>NA</td>
</tr>
<tr>
<td>Crosslinker</td>
<td>Zirconium/Borate</td>
</tr>
<tr>
<td>Possibility Value</td>
<td>1</td>
</tr>
</tbody>
</table>

No 2: This is a low temperature, low permeability and low pressure gas formation, which like the
first case is not water sensitive. Three possible recommendations are made for this system (see
table A-12 below)
### Table A-12 – Recommendations for example no 2

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Fluid 1</th>
<th>Fluid 2</th>
<th>Fluid 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rank</td>
<td>1</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Viscosifying Method</td>
<td>crosslinked</td>
<td>poly-emulsion</td>
<td>crosslinked</td>
</tr>
<tr>
<td>Energizing Method</td>
<td>foamed</td>
<td>energized</td>
<td>energized</td>
</tr>
<tr>
<td>Base Fluid</td>
<td>water</td>
<td>water</td>
<td>water</td>
</tr>
<tr>
<td>Polymer Type</td>
<td>HPG/CMHPG</td>
<td>HPG/CMHPG</td>
<td>HPG/CMHPG</td>
</tr>
<tr>
<td>Polymer Loading</td>
<td>20 lb/1000gal</td>
<td>30 lb/1000gal</td>
<td>30 lb/1000gal</td>
</tr>
<tr>
<td>Gas Type</td>
<td>N₂/CO₂</td>
<td>N₂/CO₂</td>
<td>N₂/CO₂</td>
</tr>
<tr>
<td>Gas Quantity</td>
<td>75</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Crosslinker</td>
<td>Borate/Zirconium</td>
<td>NA</td>
<td>Borate/Zirconium</td>
</tr>
<tr>
<td>Possibility Value</td>
<td>0.538</td>
<td>0.478</td>
<td>0.434</td>
</tr>
</tbody>
</table>

### Rules for the fuzzy evaluator

### Table A 13 – Rules for selecting viscosification methods

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Func. Type</th>
<th>Do Not Use</th>
<th>Use</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crosslinked</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>I</td>
<td>&lt;= 60</td>
<td>&gt;= 180</td>
</tr>
<tr>
<td>Young’s Modulus (10⁶ psi)</td>
<td>I</td>
<td>&lt;= 0.500</td>
<td>&gt;= 4</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>I</td>
<td>&lt;= 150</td>
<td>&gt;= 400</td>
</tr>
<tr>
<td>Frac Height (ft)</td>
<td>I</td>
<td>&lt;= 50</td>
<td>&gt;= 150</td>
</tr>
<tr>
<td>Linear</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt; 180</td>
<td>&lt;= 100</td>
</tr>
<tr>
<td>Young’s Modulus (10⁶ psi)</td>
<td>II</td>
<td>&gt; 6</td>
<td>&lt;= 2</td>
</tr>
<tr>
<td>frac Height (ft)</td>
<td>II</td>
<td>&gt; 200</td>
<td>&lt;= 80</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>II</td>
<td>&gt; 400</td>
<td>&lt;= 200</td>
</tr>
<tr>
<td>Pol-y-emulsion</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt; 250</td>
<td>&lt;= 120</td>
</tr>
<tr>
<td>Young’s Modulus (10⁶ psi)</td>
<td>II</td>
<td>&gt; 9</td>
<td>&lt;= 4</td>
</tr>
<tr>
<td>frac Height (ft)</td>
<td>II</td>
<td>&gt; 300</td>
<td>&lt;= 100</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>II</td>
<td>&gt; 700</td>
<td>&lt;= 200</td>
</tr>
</tbody>
</table>
### Table A 14 – Rules for selecting base fluids

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Func. Type</th>
<th>Do Not Use</th>
<th>Use</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water Sensitivity</td>
<td>II</td>
<td>&gt;=1.0</td>
<td>&lt;= 0.4</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Formation Fluid</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost and Safety</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water Sensitivity</td>
<td>II</td>
<td>&gt; 15000</td>
<td>&lt;= 8000</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt; 250</td>
<td>&lt;= 135</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>II</td>
<td>&gt; 800</td>
<td>&lt;= 500</td>
</tr>
<tr>
<td>Formation Fluid</td>
<td>Gas</td>
<td></td>
<td>Oil</td>
</tr>
<tr>
<td>Cost and Safety</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alcohol</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water Sensitivity</td>
<td>II</td>
<td>&gt;1.0</td>
<td>&lt;=0.8</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt; 300</td>
<td>&lt;= 135</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>II</td>
<td>&gt; 1000</td>
<td>&lt;= 500</td>
</tr>
<tr>
<td>Formation Fluid</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost and Safety</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table A 15 – Rules for selecting energization methods

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Func. Type</th>
<th>Do Not Use</th>
<th>Use</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal (no gas)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pressure (psi/ft)</td>
<td>II</td>
<td>&lt;= 0.30</td>
<td>&gt; 0.45</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depth (ft)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energized</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pressure (psi/ft)</td>
<td>I</td>
<td>&lt;= 0.21</td>
<td>&gt;0.21 and &lt;=0.48</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt;500</td>
<td>&lt;= 300</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>II</td>
<td>&gt;2000</td>
<td>&lt;= 750</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td>II</td>
<td>&gt;20000</td>
<td>&lt;= 8000</td>
</tr>
<tr>
<td>Foamed</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pressure (psi/ft)</td>
<td>II</td>
<td>&gt;0.4</td>
<td>&lt;=0.25</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt;360</td>
<td>&lt;=250</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>II</td>
<td>&gt;750</td>
<td>&lt;= 500</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td>II</td>
<td>&gt;10000</td>
<td>&lt;= 4000</td>
</tr>
</tbody>
</table>
Table A 16 – Rules for selecting gas type

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Func. Type</th>
<th>Do Not Use</th>
<th>Use</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Fluid</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt;275</td>
<td>&lt;= 200</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td>II</td>
<td>&gt;8000</td>
<td>&lt;= 5000</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>II</td>
<td>&gt;600</td>
<td>&lt;= 450</td>
</tr>
<tr>
<td>CO2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base Fluid</td>
<td>Oil</td>
<td></td>
<td>Water</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>I</td>
<td>&lt;60</td>
<td>&gt;= 275</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td>I</td>
<td>&lt;1000</td>
<td>&gt;= 4500</td>
</tr>
<tr>
<td>Frac Length (ft)</td>
<td>I</td>
<td>&lt;50</td>
<td>&gt;= 450</td>
</tr>
</tbody>
</table>

Table A 17 – Rules for selecting polymer type

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Func. Type</th>
<th>Do Not Use</th>
<th>Use</th>
</tr>
</thead>
<tbody>
<tr>
<td>Guar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost</td>
<td>I</td>
<td>&lt;200</td>
<td>&gt;= 150</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt;200</td>
<td>&lt;= 150</td>
</tr>
<tr>
<td>Frac Length(ft)</td>
<td>I</td>
<td>&lt;50</td>
<td>&gt;=50</td>
</tr>
<tr>
<td>Permeability</td>
<td>I</td>
<td>&lt;0.01</td>
<td>&gt;10</td>
</tr>
<tr>
<td>HPG</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost Index</td>
<td>II</td>
<td>&gt;300</td>
<td>&lt;= 200</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt;300</td>
<td>&lt;= 200</td>
</tr>
<tr>
<td>Frac Length(ft)</td>
<td>I</td>
<td>&lt;50</td>
<td>&gt;=50</td>
</tr>
<tr>
<td>Permeability</td>
<td>II</td>
<td>&gt;50</td>
<td>&lt;0.05</td>
</tr>
<tr>
<td>CMHPG</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost Index</td>
<td>II</td>
<td>&gt;450</td>
<td>&lt;= 350</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt;450</td>
<td>&lt;= 350</td>
</tr>
<tr>
<td>Frac Length(ft)</td>
<td>I</td>
<td>&lt;25</td>
<td>&gt;=25</td>
</tr>
<tr>
<td>Permeability</td>
<td>II</td>
<td>&gt;10</td>
<td>&lt;0.001</td>
</tr>
<tr>
<td>HEC or Xanthan</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost Index</td>
<td>I</td>
<td>&lt;25</td>
<td>&gt;=25</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Frac Length(ft)</td>
<td>II</td>
<td>&gt;50</td>
<td>&lt;=50</td>
</tr>
<tr>
<td>Permeability</td>
<td>II</td>
<td>&gt;10</td>
<td>&lt;0.001</td>
</tr>
<tr>
<td>Phosphate Ester</td>
<td></td>
<td></td>
<td>oil-based fluid</td>
</tr>
</tbody>
</table>
Table A 18 – Rules for selecting crosslinker type

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Func. Type</th>
<th>Do Not Use</th>
<th>Use</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Borate</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>II</td>
<td>&gt; 300</td>
<td>&lt;= 135</td>
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