SELECTION OF THE RIGHT HYDRAULIC FRACTURING FLUID FOR UNCONVENTIONAL RESERVOIR SIMULATION

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ABSTRACT

Unconventional resources are of major importance to the oil and gas industry due to its enormousness, however, due to the low permeability of these resources, there is a need for hydraulic fracturing. Hydraulic fracturing is the process of bombarding rocks with fluids at a rate high enough to create fractures in rocks to aid productivity. Selection of the right hydraulic fluids and additives determines the success or failure of the hydraulic fracturing process.

Most researchers take into consideration the various types of hydraulic fracturing fluids and functions of the numerous additives used in fracturing. However, there is minimal knowledge of the fracturing fluid to consider based on the formation characteristics. Therefore, this research seeks to find the relationship between the rock properties of certain unconventional formations and the hydraulic fracturing treatment that is used by operators to establish a guideline that aids in the selection of fracturing fluids.

Information of 400 fractured wells that were treated within 2015 was collected for the Bakken, Barnett, and Haynesville formations from *fracfocus* - which is a database that keeps information about all the fracturing fluid treatment used for wells in the United States. The trend of fracturing treatment with regards to the characteristics of the formation of these three formations was studied and a guideline developed based on the trend of fluids used in these formations.

KEYWORDS: Hydraulic fracturing, fracturing fluids, additives, proppants.

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CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND

The concept of resource triangle makes it known that all natural resources are distributed lognormally in nature (S. A. Holditch, 2006). This concept explains that for all resources including gold, silver, zinc, oil, natural gas, etc. the rich deposit with high-grade mineral content are mostly small in size and are easy to extract. The conventional deposit mostly has high permeability hence extraction and production are easy. As one goes down the resource triangle, the permeability decreases and these unconventional resources are mostly in larger sizes as compared to the conventional resources of high permeability. Figure 1 illustrates the concept of resource triangle for natural gas.

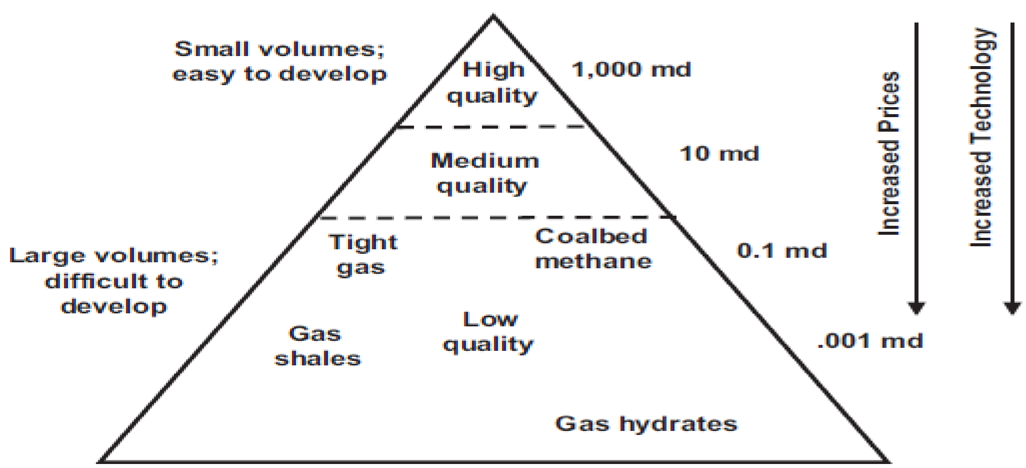


Figure 1-Resource Triangle for Natural Gas (Holditch, 2006)

Unconventional resources include coal bed methane, gas shale, gas hydrates, tight gas sand, oil shale, and heavy oil. Shale gas normally occurs in mudstone interbedded with layers of sandstone (Li, Xing, Liu, & Liu, 2015). Tight gas is defined as ‘a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by the use of horizontal wellbore or multilateral wellbore' (S. A. Holditch, 2006).

As the world demand for energy keeps increasing and cleaner forms of energy are sought for, unconventional resources are becoming of major concern to the oil and gas industry. This is because the resource is enormous and may cover the world's energy needs for more than a century (Alberta Environment and Parks, 2015). Development of unconventional resources creates jobs and fuel for the economy.

Due to the low permeability of these formations, there is a need for stimulation. Hydraulic fracturing and horizontal drilling have enabled the extraction of a large amount of oil and gas found in shale and tight formation especially in the United States. According to the U.S Energy department, about 95 percent of wells drilled today are hydraulically fractured. This accounts for about two-thirds of the total marketed gas production and about half of the U.S crude oil produced (Alberta Environment and Parks, 2015). For the past 150 years since the development of energy resources started in the United States, about 4 million oil and gas well has been drilled. Out of this number, almost 2 million has been hydraulically fractured. According to the U.S Department of Energy, 95 percent of new wells drilled today are hydraulically fractured, resulting in more than 43 percent of total U.S oil produced and 67 percent of natural gas (Alberta Environment and Parks, 2015).

Hydraulic fracturing is one method of stimulation that helps in increasing productivity. Hydraulic fracturing is a process of using fluids to fracture reservoir rocks. A hydraulic fracture is formed by pumping fluid into the wellbore at a rate suitable enough to create a pressure that exceeds the strength of the rocks downhole (Gandossi, 2013). A hydraulic fracturing fluid is a combination of a based fluid, additive and proppant. There are different types of fracturing fluids. They are water-based fluids, foam-based fluids, oil-based fluids, alcohol-based fluids, and emulsion based fluids.

The main function of the hydraulic fracturing fluid is to create a conductive conduit from the wellbore into the reservoir and also to transport proppant into the created fractures to create a pathway for reservoir fluids (Harris, 1988).

1.2 PROBLEM STATEMENT

Selection of the right hydraulic fracturing and additive determines the success of the fracturing process. If the right fracturing fluid and the additive is not chosen, the formation can be damaged and proppant might not be placed as desired in the formation (Hongjie Xiong, Davidson, Saunders, & Holditch, 1996). Hence, there is a need to develop a mechanism that aid in the selection of the right hydraulic fracturing fluid. Most research papers written on the selection of hydraulic fracturing fluids take into account individual wells or cluster of wells in a field as case studies. These papers take a detailed account of the efficiency of the fracturing processes based on the different fracturing fluids in specific fields. Therefore, there is a need for research that takes into consideration the general overview of the various chemicals used for fracturing to aid an engineer in the selection of the right fracturing fluid for unconventional reservoirs.

1.3 OBJECTIVES

The main objectives of this work are to:

1. Study various hydraulic fracturing fluids and additives and to determine what type of fracturing fluid should be used for a different kind of reservoir formation.
2. Provide a guideline on how to choose and evaluate various fracturing fluids by developing a flow chart.

1.4 METHODOLOGY

1. Literature survey of hydraulic fracturing fluid types, additives and their functions that are used in fracturing in tight and shale formation.
2. Study the formation characteristics of Bakken, Haynesville, and Barnett.

3. Study the details of the database of fracfocus which reports all the chemicals used for fracturing treatment in these formations.
4. Apply statistics and data analysis algorithm to collected fracking fluids and additives.
5. Explore the relationship between the fracking fluids and the reservoir petrophysical, geomechanical and fluid properties of the above formations and investigate the changes over time.

CHAPTER 2

LITERATURE REVIEW

2.1 INTRODUCTION

The petroleum industry is in an era where unconventional resources are no more a byword but a boast to the sector. In light of this, many research works are investigating how best the industry can exploit this resource and make it beneficial to the world. This chapter is a review of various literature spanning from what unconventional resources are, the various form of unconventional reservoirs, hydraulic fracturing and finally to fracturing fluids and additives.

2.2 UNCONVENTIONAL RESOURCES

Holditch (2006) proposed the need for research and exploration in the unconventional reservoir through the concept of resource triangle. To verify the concept of resource triangle which was originally reported by Masters in 1979, Holditch (2013) analyzed 25 basins in North America to describe the distribution according to the resource triangle concept. The findings indicated that over 90 % of the technically recoverable resources in natural gas formation are located in unconventional resources. With this finding, the author proposed that his findings can be extrapolated for all basins that produce a considerable volume of hydrocarbon in the world. This finding confirmed that indeed, the large quantity of the total hydrocarbon resources are unconventional just according to the resource triangle concept originally established by Masters in 1979. Holditch concluded that any hydrocarbon basin that has produced a huge volume of hydrocarbon over the past century could have a huge volume of unconventional hydrocarbon awaiting discovery and development.

Holditch (2013) defined an unconventional reservoir as "a low-quality reservoir that must be stimulated to produce at commercial flow rates and recover commercial volumes of hydrocarbon".

According to King (2012), conventional sandstones have a permeability of 0.5 – 20 millidarcy. The diagram below gives the range of permeability for both conventional and unconventional resources.

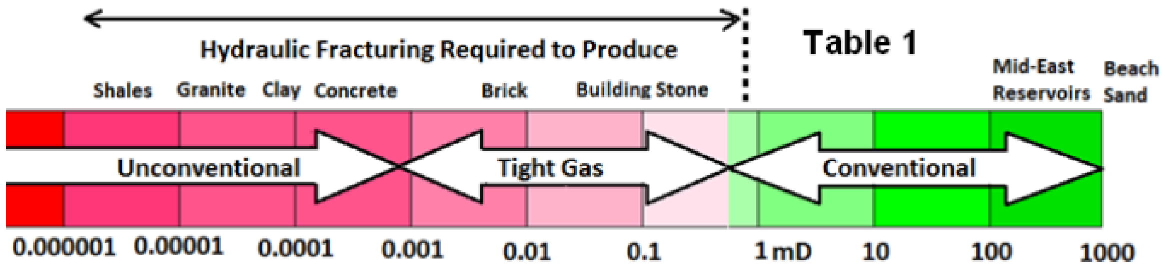


Figure 2-Permeability Ranges for Various Formation Types King (2012)

Sunjay and Kothari (2011) described the various types of unconventional reservoirs with an emphasis on shale gas. They categorized unconventional resources coalbed methane (CBM), methane gas hydrate, shale gas, tight gas, oil shale, and heavy oil. Sunjay and Kothari defined shale gas as 'a natural gas from shale formations which acts as both the source and the reservoir for the natural gas'. Shales are known for their low permeability. Shales are however considered as source rocks, for shale to become a reservoir rock it must have a containment also known as a trap. Production from shale formation requires a form of stimulation to produce fractures for permeability in order to unlock gas from these formations to produce economically. Shale gas reservoirs normally have dual porosity. The authors describe the dual storage as the rock matrix and natural fractures for the storage of hydrocarbon. However, because of the plastic nature of shale formation, these natural fractures are closed due to compaction from the overburden rock. The permeability of shale reservoirs in mostly in the order of nanodarcy making commercial production without simulation impossible. Due to this, most shale gas reservoirs are hydraulically fractured in order to reconnect and activate these natural fractures.

Holditch (2006) defined tight gas sand as ‘a reservoir that cannot be produced at economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by the use of a horizontal wellbore or multilateral wellbores.’ Holditch highlighted that most unconventional reservoirs need much engineering manpower and data to understand and develop this type of reservoirs as compared to conventional type. the U.S receives about 20% of total gas production is from tight gas reservoirs and the volume of technically recoverable gas from U.S accumulation is about 185 Tcf. Holditch defined a technical recoverable as, “knowing the gas to exist with an improved technology available for drilling, completing, stimulating and production from the reservoir”. Holditch also analyzed that for effective stimulation, the geology of the basin should be known.

Holditch (2013) added that the low quality in an unconventional reservoir is due to the low permeability of the formation or high viscosity of the oil. For low permeability reservoirs such as tight oil, tight gas, gas shale, and coalbed methane reservoirs, stimulation such as hydraulic fracturing and horizontal wells can help produce them effectively. Comparatively, Holditch added that for heavy oil and oil shale, heat is needed to reduce the oil viscosity. Also, for gas hydrate reservoirs research and development are still ongoing for the required method to produce them economically. Holditch predicted that by 2030 gas production from unconventional reservoirs will contribute about 75% of the total gas consumption in the United States. Holditch (2013) finally recommended based on his analysis that operators should start major exploration all around the world in the shales and source rock in the primary oil and gas basins for huge sources of unconventional resources as the conventional reservoirs deplete.

2.3 HYDRAULIC FRACTURING

King (2010) studies the evolution in shale fracturing over the last thirty years. The author added that shale fracturing research started way back in the 1970s. The first shale gas well was drilled in 1821 in Fredonia, New York. According to King, shale gas development has helped increase the recovery in shale from 2 % to about 50 %.

Hydraulic fracturing is one of the widely used methods of stimulating unconventional reservoirs. One might ask what at all is hydraulic fracturing. Sunjay and Kothari (2011) described hydraulic fracturing as a process which involves bombarding the rocks with millions of liters of slurry to open up the pores for the hydrocarbon to flow. Economides and Nolte (2000) defined hydraulic fracturing as “the process at which a fluid is pumped into the wellbore at a rate faster than the fluid can escape from the wellbore”. According to King (2012), the first hydraulic fracturing experiment was in 1947 and the process was commercialized in 1950.

Economides and Nolte (2000) described hydraulic fracturing as a multidisciplinary process with no rule of thumb therefore, sound engineering judgment is critical in its decision making. When the treatment pressure is above the formation fracturing pressure, formation matrix will be fractured and the fracture orientation is perpendicular to the minimum stress which could be horizontal or vertical depending on their relative magnitude. As the breaking of the formation continues, the injected fluid is being exposed to the newer parts in the formation. Therefore, the rate of fluid loss increases. The fractures propagate deeper into the formation if the rate of fluid injection is kept higher than the rate of fluid loss. Once the injected fluid is stopped and the injected fluid leaks out of the formation, the growth in the propagation of fractures stops. The created fractures would close when the treatment stops. To keep the fracture open, proppant agent is needed in the hydraulic fracturing fluid. These proppants are mostly sand or high strength substances. In carbonate reservoirs, acid addition into the fracturing fluid help in the dissolution of some the formation thereby helping to produce a conductive path into the reservoir for the production of hydrocarbon.

In hydraulic fracturing, the pad which is the injected fluid without proppant is introduced to initiate the fracture by breaking the wellbore. After that, the proppant-laden slurry is transported to keep the fracture open. During the proppant-laden stages, the first proppant is mostly transported in small concentration. This is because, at this point in the hydraulic fracturing process, fluid loss is still happening with the highest occurring at the fracture tips. Because of this, when the proppant-laden slurry is pumped through the well into the fractures then further to the fracture tips, the slurry is quickly lossed into the formation through the fracture tips, even faster than the tip is able to propagate fracture growth. As the slurry is loss to the formation, the concentration of the solid proppant increases inside the fracture. The proppant addition is engineered so as to get the required concentration as designed. The slurry concentration is increased gradually until the entire fracture is filled with the desired amount of slurry as designed. Beyond this process is an additional process called 'Tip Screen-Out' fracturing where the width of the fracture increases due to continuous pumping. Finally, the flush fluid is pumped to clean the wellbore of all proppants. The well is then shut in for a while to allow the fluid to leak off so as the fracture closes on and stress the proppant pack. Shutting-in of the well also allows the temperature to reduce the viscosity of the fracturing fluid.

2.4 MYTH ABOUT HYDRAULIC FRACTURING

Concerning the massive hydraulic fracturing in the development of unconventional reservoirs, King (2012) addressed the various myths and the engineering truth lacking about hydraulic fracturing.

One major challenge is the numerous criticism surrounding the hydraulic fracturing process. A lot of environmentalists and social commentators believe that fracturing causes major pollution in the environment. These group of people interchanges hydraulic fracturing with the whole well development process from drilling to production. Engineers, however, consider hydraulic fracturing as a stimulation procedure where a fluid is a pump at a faster rate to cause fracturing of the formation to increase productivity. From the various kinds of literature reviewed by King, it revealed that first of all, from scale drawings, the fresh water formation is about 1000 feet or 305 meters from the surface. Also, the separation from the surface to the pay zone in shale formation is about 7000 ft. King made it clear in his article that, fracture height predicted from a computer model and confirmed by micro-seismic monitoring during the fracturing process, post-frac tracer flows, temperature logs and a lot of other similar mechanism show that most vertical fracture growth is about 300 ft. (90 m) or less. Fractures mostly have barriers such as a leak of the fluid through the formation. Therefore, these fracs will by no means reach the depth of the fresh-water formation.

Also, these social commentators and most citizens worry about methane showing up in the water table if fractures are several meters away from the freshwater zone. From King's paper, it was also known that methane found in the water table may be as a result of both man-made and natural occurrences. The natural occurrence as explained by this article can possibly due to biogenic methane from the decay of organic materials or thermogenic methane from the depth of the earth as a result of seeps from outcrops of shales and coal that have been evolving for millions of years especially in areas where there is freshwater well in the water table.

King (2012) suggested that methane which is a contaminant in the water table can also be from old hydrocarbon wells that were not constructed properly and were developed as the same depth as that of the water zone. Most of these old wells were developed before the evolution and invention of hydraulic fracturing and most of these wells existed before proper regulations were set up for regulation in the oil and gas industry.

One argument made by King in his article is that, if the reservoirs are able to house hydrocarbon in those reservoir rocks for ages, then it means these rocks can contain these fracturing fluids and additives without any upward movement due to the barriers called cap rocks that prevent upward movement

2.5 FRACTURING FLUIDS

Harris (1988) highlighted that the function of fracturing fluids is to create a conductive path linking the wellbore with the formation and also to carry proppant into those fractures thereby retain the conductive path created. H Xiong & Holditch (1995) explained that in the selection of the ideal fracturing and additives certain critical elements should be considered. This includes: (1) the formation should be compatible with the fracturing fluid, (2) Fracturing fluid should have a proper viscosity to create the fracture and carry proppants, (3) the fracturing fluid is less damaging to the formation and proppant pack, (4) the fracturing fluid should be easy to prepare and safe to use on site, and easy to pump, with a minimal frictional pressure loss. Before even considering the various alternatives of fluid to use, there should be information about the formation's sensitivity to water, formation pressure, formation temperature, permeability, and fracture half-length.

Montgomery (2013) described the history of fracturing fluids, types of fracturing fluids, the engineering requirement of good fracturing fluid and the necessity of right viscosity in preparation of fracturing fluids. The whole fracturing process begins with selecting the pad volume required to achieve the fracture geometry as designed. After that, it is necessary to choose the desired viscosity for the fluid. Montgomery explained that the viscosity is important, because:

- It helps the fluid to provide a fracture width that is adequate to allow the entry of proppant into the fracture.
- Viscosity is that parameter that helps provide a desire fracture height growth or prevent the breaking out of fractures into undesirable zones such as water zones.
- Viscosity also regulates the fluid ability to transport the proppant into the fracture tips.
- Viscosity help in controlling fluid loss.

As noted earlier from previous works of literature, Economides and Nolte also consider viscosity as the most important property of a fracturing fluid.

Additionally, Montgomery (2013) pointed out that the following should be considered before selecting the appropriate fracturing fluid system:

- Safety: the fluid should not be a dangerous substance for the site workers.
- Environmentally acceptable: the component in the fluid should not be a pollutant to the environment.
- Breaker: the fluid should have the capacity to break to a low viscosity liquid to enhance the flowing back of the fluid and cleaning of the created conductive path called fractures.
- Cost Effective: there is no point in selecting a fluid component that makes the whole process uneconomical. Cost should be a critical factor in the selection of the fracturing fluid components.
- Compatibility: the fluid should not cause a reaction and damage between the formation's mineralogy and the formation fluid.
- Easy to mix: the fracturing fluid components must be easy to mix especially under harsh weather conditions.
- Fluid loss: the fluid should have the ability to regulate fluid loss.

Montgomery stated that overestimation of viscosity causing high viscous fluid can lead to increase in cost, high treatment pressure which can lead to unnecessary height growth of fracture which might not be desired and can even lead to reduced fracture conductivity because most chemicals used in increasing viscosity leaves remainings which end up reducing the permeability of the proppant. Montgomery made an interesting submission that, getting the right or precise value for the viscosity of the fracturing fluid can also be overengineered. Montgomery analyzed from the equation shown that the viscosity, μ is directly proportional to the treatment pressure, P_{net}.

$$P_{net} \propto \frac{E^{\frac{3}{4}}}{H}[\mu QL]^{\frac{1}{4}} + P_{tip}$$

Also, treatment pressure is also the determinant of the fracture width, thus a 100 % error in viscosity results in a 19 % error in finding the fracture width. This error in estimation goes on in finding the volume of fracturing fluid required. Montgomery assumed that about half of the fracturing fluid volume leaks off to the formation, which reduces the 19 % error in width to 9.5 % error in the calculation for the volume of the fracturing fluid required. The author also clarified that the complexity and numerous approaches for finding viscosity make the choice of the particular viscosity values almost unattainable. There are various types of fracturing fluids. These include:

- Water-based fluids
- Oil based fluids
- Energized fluids
- Multi-phase emulsions
- Acid Fluids

2.5.1 Oil based fluids

Montgomery (2013) showed that the first fracturing fluid used for experimental fracture treatment was made up of gasoline gelled with palm oil and crosslinked with naphthenic acid. This technology was established during the Second World War and its ordinarily called 'Napalm'. Economides and Nolte (2000) showed that oil-based fracturing fluids were used because they cause minimal damage to the reservoir formation than that of water-based fluid, however, they are very expensive and difficult to be controlled. The natural characteristic viscosity of oil-based fluids makes it an advantage over that of water-based fluids. In the early 1960s, aluminum salts of carboxylic acids were used in increasing the viscosity of oil-based fracturing fluid. Around the era of the 1970s, enhancement of viscosity in hydrocarbon based fracturing fluids was upgraded by the use of aluminum phosphate ester salts which aided in temperature stability and suspension of proppant for easy transportation into fractures, and this method of thickening oil based fracturing fluids is the most desired method used today. A reaction of aluminum complexes and phosphate ester results in a long chain of polymers. The diagram below shows the complex reaction in viscosifying oil based fracturing fluids.

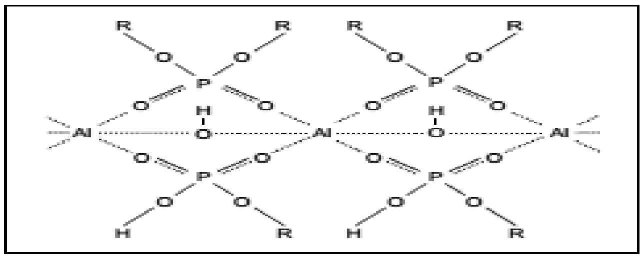


Figure 3-Proposed structure of the aluminum phosphate ester polymer chain

Source: Economides & Nolte (2000)

Economides & Nolte (2000) explained that the R group shown in figure 3 is the chains of a hydrocarbon comprising of carbon atoms ranging from 1 to 18 atoms. This R group is mostly soluble in oil and also aid in maintaining the aluminum phosphate ester polymer in solution. This R group has a high affinity for oils such as kerosene and diesel with carbon atomic content ranging between 12 and 18. Though most crude oils are well-matched with aluminum phosphate ester gelling system, however, paraffin and asphaltenes which has a higher number of carbon atoms do not mostly bound in this system. The viscosity of this system regulated by the amount of aluminum compound and phosphate ester. The viscosity of the aluminum phosphate ester gel and improvement of its temperature performance by increasing the quantity of the polymer. However, increasing the viscosity at the surface makes it difficult to draw fluid from tanks using a pump. Due to this a method called ‘on the fly' was developed where the thickening gel is added to the fluid as the fluid is pumped downhole.

2.5.2 Acid-based fluids

Economides and Nolte (2000) discussed acid based fracturing fluid. Acid fracturing is mostly used in carbonate reservoirs. Acid fracturing is prepared by injecting mostly hydrochloric acid (HCl) into carbonate formation at a pressure higher than the formation parting pressure. Acid fracturing can be in opening up existing fractures in naturally fractured reservoirs. The effective length of the fracture depends on the etched length caused by acid dissolution. The etched length also depends on the bulk of acid used, its reaction rate and also the fluid loss from the fracture into the reservoir formation. One major advantage of the acid treatment is that there is no need to pump in propping agents since the acid dissolution causes etching in an unorderly and ununiformed way, therefore the conductive path remains even when the fracture closes. Notwithstanding, acid treatment is more costly as compared to other non-reactive treatment fluids. Also, fluid loss control seems to be difficult in acid-based fluids because the continuous wearing off of fracture faces making it almost impossible to deposit an efficient filter cake barrier.

2.5.3 Multiphase fluids

Economides & Nolte (2000) also discussed multiphase fluids such as foam and emulsion. Foam is the stable mixture of a liquid phase and gaseous phase. Its stability is derived from the addition of a surface-active element (surfactant). The function of the surfactant is to lower the interfacial tension and soothes the thin film of the liquid and avoids joining of the cells. Foams help in improving the liquid recovery from a propped fracture and are perfectly used in reservoir formations with low pressures. The quality of foam is directly proportional to the volume of gas contained in the foam. As a result, foaming the fluid in a water-based fracturing fluid can be excellent for water sensitive reservoirs. In low permeability reservoirs, the gas bubbles in a foam can serve as an effective way of preventing fluid loss as the size of the bubble is almost similar to the size of the pores. Polymers can be used in thickening the liquid phase of foam to increase its stability.

As part of the multiphase fluids, Economides & Nolte (2000) explained what emulsions are and how they can be used. Emulsions are dispersion of two immiscible fluids, such as oil in water. Emulsions can also be stabilized by the use of surfactants. According to Economides & Nolte, emulsion-based fracturing fluids are not new in the field of fracturing. One mostly used emulsion based fracturing fluid is a poly emulsion, which is a composite of 67% hydrocarbon internal phase, 33% viscosified brine external phase, and an emulsifying surfactant. Increasing the viscosity of the liquid phase results in an increase in the emulsion. The process of viscosification is mostly done by the use of the polymer. The advantage of this type of fluid fracturing fluid is that there is minimal damage of formation since just a little of a polymer is used, just about one-sixth to one-third of that used in the normal water-based fracturing fluid. However, the drawback in using this type of fracturing fluid is that it is relatively expensive and also the viscosity of these fluids decreases significantly as the temperature increases hence become a hindrance in hot wells.

2.5.4 Water-based fluids

Water-based fracturing fluids are widely used because of its characteristic low cost, high performance, and ease of handling. Economides and Nolte (2000) gave a breakdown of what water-based fluids are. Ideally, various water-soluble polymers can be used to make a viscosified solution good enough to suspend proppant at ambient temperature, nevertheless, as temperature increases, this cannot be said for all those numerous fluids. To find a solution to this, the concentration of the polymer can be increased to sustain the viscosity at high temperature. However, this method is not economical. A more convincing approach is the use of crosslinking agents. Crosslinking agents are used to increase the molecular weight of the solution, thereby increasing the viscosity of the solution. Guar gum is one of the first polymers used to increase the viscosity of water for fracturing purposes.

Economides and Nolte (2000) explained: "guar as a long-chain, high-molecular-weight polymer composed of mannose and galactose sugars". Guar is a polysaccharide since it is made up of sugar units. Montgomery (2013b) confirms that about 33 % of all plant matter contains a cellusosan organic compound which has the formula $(C_6H_{10}O_5)n$. Economides and Nolte (2000) explained further that guar gum is a product from the endosperm of guar beans grown mainly in India and Pakistan. The bean is processed to form the gum by removing from the pod and to separate the endosperm from the embryo and ground further into powder. Since guar is hydrophilic, it clinches to water, swells and becomes hydrated when water is added thereby extending to the whole of the solution, as a result, increasing the viscosity of the solution. The authors also highlighted that the ratio of mannose to glutose is in the range of 1.6:1 to 1.8:1. Also, the processing of guar gum from its bean does not completely remove the other plant material that is non-soluble in water. Empirically about 6-10 % of these insoluble plant materials are still found in the guar gum. The authors also emphasized that guar can be derivatized with propylene oxide to produced hydroxypropyl guar (HPG).

Economides and Nolte (2000) explained hydroxypropyl guar as a product produced from guar by a chemical reaction that changes some of the OH sites to $–O–CH_2–CHOH–CH_3$, thereby removing some of the crosslinking sites. This process of changing guar to HPG helps removes most of the residual non-soluble plant material in guar, reducing the insoluble residue just to 2 % to 4 %. HPG is more stable at high temperatures than guar due to the hydroxypropyl substitution. This makes HPG more suitable for high temperature (>300°F [150°C]) wells. Because of the less water affinity nature of hydroxypropyl substituents, HPG is more soluble in alcohol than that of guar.

2.5.5 Polymer-free water-based fluids

Another group of chemicals is the polymer-free, water-based fracturing fluids which can be prepared by the use of viscoelastic surfactants (VES). These surfactants are of quarternary ammonium salt with a long chain of fatty acids. This type of surfactant entails two regions, the head, and the tail. The head has a high affinity for water whiles that of the tail is highly hydrophobic. When these surfactants come into contact with water, the resultant substance is called micelles. The hydrophilic head is mostly observed at the outside in direct contact with the water phase while the hydrophobic tail is shielded from the water phase by being inside. If there are salts present in the aqueous face, a rod-like structure of the micelle is observed. There is an increase in viscosity of the fluid when the concentration of the surfactant is sufficient thereby causing the micelles to mingle with each other resulting in an increase in internal friction. Hydrocarbons and fluids such as formation fluids can easily distort the viscosity of VES. This becomes an advantage after a fracture treatment. This is because there are no residues left after clean up as compared to polymer-viscosified fluids, therefore, there is minimal damage of proppant pack and fracture face.

Another derivative from guar is carboxymethyl hydroxypropyl guar (CMHPG). This is a double-derivatized guar which contains the hydroxypropyl functionality of HPG and also a carboxylic acid substituent. This type of guar derivative was initially used for low-temperature wells. However, a crosslinked of CMHPG with zirconium crosslinking agent can be used to produce fluids with higher viscosity which is more adaptable to higher temperatures than that HPG.

Economides and Nolte (2000) also discussed cellulose derivative which is periodically used in fracturing fluid. Example of these cellulose derivative used is hydroxyethylcellulose (HEC) or hydroxypropyl cellulose (HPC). HEC is used when an extremely clean fluid is sought after. HEC has a very similar structure with that of guar as it is also a polysaccharide. However, there is a significant difference between guar and hydroxyethylcellulose. The difference is based on the arrangement of the hydroxyl pairs, while guar has a cis orientation of the pairs, hydroxyethylcellulose on that other hand has a trans orientation of the hydroxyl pairs. Another type of polymer discussed by the authors is xanthan gum. Xanthan is a biopolymer which is a product produced by metabolic reactions by a microorganism called *Xanthomonas campestris.* Xanthan has an advantage over HPG because xanthans fluids act as power-law fluids even at relatively low shear rates whereas HPG act as Newtonian fluids at low shear rates. This characteristic of xanthans allows them to suspend proppant better than of HPG. Regardless, xanthans are not often used for fracturing treatment because of their costliness as compared to guar and cellulose derivatives.

Montgomery (2013) discussed another form of fracturing fluid called water frac. Water frac is known to consist of water, a clay control agent and a friction reducer. Occasionally, water recovery agent (WRA) is added to minimize any relative permeability or water block influence. This type of fracturing fluid has the advantage of being low in cost, easy to mix and has a capacity to recover and reuse the water. The major disadvantage associated with this form of fracturing fluid is that it usually has a low viscosity which results in narrow fracture width. Due to its low viscosity, proppants are transported at a very high rate.

2.6 ADDITIVES

Harris (1988) stated that selection of the right additive for a fracturing process can ‘‘make or break’’ the whole process. S. a Holditch, Xiong, Hoiditch, & Rueda (1993) stated that the selection of right additive for a fracturing treatment is very critical to the whole fracturing process. Similarly, H Xiong & Holditch (1995) also added that the success of a fracturing process depends strongly on the type of fracturing fluid and additive used. Harris (1988) highlighted that the two main purposes of fracturing fluid additives are (1) ensure the effective creation of fractures and to aid in the transportation of proppants and (2) minimalize formation damage. Types of additive that help in the creation of fracture are: viscosifiers, temperature stabilizers, pH regulators and fluid-loss control substances and those that help in the reduction of formation damage are: gel breakers, biocides, surfactants, and clay stabilizers.

According to Harris (1988),   that the cost of additives should never be a factor in the selection of the right additive as their cost is negligible compared to the cost of drilling and completion.

There are various types of additives. This include:

- Gelling agents
- Crosslinkers
- Breakers
- Fluid loss additives
- Bactericides
- Surfactants and Non-emulsifying agents
- Clay control Additives.

2.6.1 Water

Though water may not be considered as an additive, it is an integral component in fracturing fluids. Though seawater can be used for this purpose, however, there is a risk of aiding in the introduction of sulfate that can lead to the formation of sulfate scales by its reaction with connate reservoir water. Seawater can also be a source of sulfur for bacteria to strive on. Flow back water has become one other major source of water used recently especially for slickwater fracs. For flowback water to be used, care must be taken because of the residual gel breaker in them.

2.6.2 Viscosifiers

High viscous fracturing fluid creates wider and even higher fractures. A substance such as guar, cellulose, hydroxypropyl guar, carboxymethyl hydroxypropyl guar, or carboxymethyl hydroxyethyl cellulose help in thickening fluid with temperature ranging from 60 to about 400 ^{o}F. Usually increasing the concentration of viscosifying polymers increase the viscosity of the fracturing fluids. However, this process is not economical. The concept of crosslinking is a cost-effective way to increase the viscosity of fluid without any operational challenges such as sand wetting and high pumping pressures. Viscosity multiplying effect is mostly achieved by crosslinking the base gel polymer with transition metal cation such as aluminum, antimony, borate, titanium, and zirconium. Crosslinking depends on the compatibility of the crosslinking agent with the polymer. This process is pH and temperature dependent. Crosslinking changes a polymer from a viscous fluid to viscoelastic fluid. This viscoelastic elastic fluid is susceptible to shear. Above a temperature of 225 ^{o}F, guar and cellulose derivative degrade due to dissolved oxygen in the treated water. Due to this, chemical stabilizers such as methanol and thiosulfate are needed to prevent a reduction in viscosity. These stabilizers decelerate the rate of viscosity at high temperatures.

According to Montgomery (2013b), increasing viscosity of a fracturing fluid help in increases the fracture width that can receive a higher concentration of proppants, minimize fluid loss which results in fluid efficiency, aids in carrying of proppants and finally reduce frictional pressure. Viscosity is dependent on the molecular weight of the polymer. As concentration and chain length of the viscosifier increases, viscosity also increases.

Crosslinkers, as discussed by Economides & Nolte (2000), are used in linking polymer chains to one another. Several cations of metals can serve as crosslinkers for water-soluble polymers. Such metal compounds include borate, titanium (IV), zirconium (IV) and aluminum (III). Complexes of transition metals and compounds of borates form a complex by reacting with cis-OH pairs on the galactose side chains of guar and HPG. These complexes formed can undergo a chemical reaction with other polymers to form a crosslinked network. High viscosity solutions develop as the molecular weight of species increases to about twice of the polymer because of the multiple crosslinking at the various cis-hydroxyl sites. Borate ion, a crosslinking species depends on the pH value to produce a highly viscous fluid with substances like guar and HPG. It is known the main crosslinking species borate ion $B(OH)_4^-$.

$$H_3BO_3 + OH^- \rightarrow B(OH)_4^-$$

From the equation, it can be seen that to keep $B(OH)_4^-$ in solution, the pH should be high to shift the equation to the right. Therefore, borate concentration is a function of pH. The diagram below depicts borate dependency on pH.

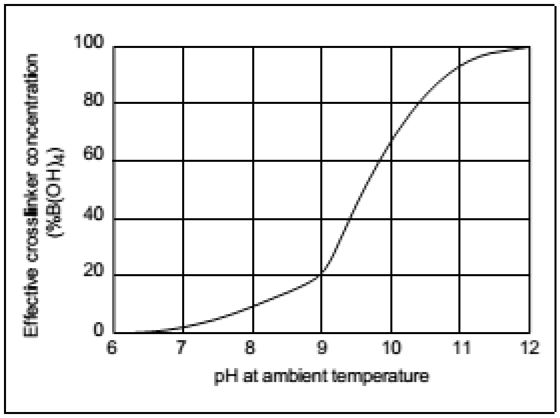


Figure 4-Borate as a function of pH

Source: Economides & Nolte (2000)

According to Economides & Nolte (2000), transition metal crosslinkers are preferable for high-temperature and low pH environment. Titanium and zirconium complexes are used as crosslinkers because of their affinity for cis-OH and carboxyl groups which are stable at high temperature. Though all fracturing fluids are affected by heat and shear, however, it is possible for borate to reform after degradation of the polymer but transition metal polymer is irreversible after it is degraded by shear. To obtain the preferred performance of fracturing fluids, the concentration, pH and chemical contamination should be considered for the crosslinked fluid. According to Montgomery (2013b) iron, aluminum and chromium can also be used as crosslinking agents for guar, however, they are not mostly used. Iron is one material that should be avoided during crosslinking because it can cause premature crosslinking. The figure below summarizes the various crosslinking agents and their working pH.

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

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

Figure 5-Characteristics of commonly used crosslinkers

Source: Economides & Nolte (2000)

2.6.3 Breakers

Breakers are to reduce the viscosity of the high viscous fluid used for the carrying of proppant into the fracture. It is very necessary to reduce the viscosity of these fracturing fluids because high viscous fluid would drastically reduce the viscosity of the proppant pack which leads to a reduction in the effective permeability of the fracture. This reduction of permeability is achieved by the breakers by splitting the polymer into fragments with smaller molecular weight. The commonly used gel breakers are oxidizers and enzymes. Examples of oxidizers widely used as fracturing fluid breakers are the ammonium, potassium and sodium salts of peroxydisulfate ($S_2O_8^{2-}$). Thermal breakdown of peroxydisulfate results in extremely reactive sulfate radicals which breaks the polymer into a fragment of smaller molecular weight leading to a reduction in its viscosity. The equation for the thermal decomposition of peroxydisulfate is as follows:

$$O_3S - O{:}O - SO_3^{2-} \rightarrow \cdot SO_4^{-} + \cdot SO_4^{-}$$

Peroxydisulfate breakdown is highly temperature dependent. At a temperature below 125 °F, this thermal reaction is slow and amines are needed as a catalyst to speed up the reaction. When the temperature is above 180 °F, the reaction is so fast that there is a drastic reduction in the viscosity of the fracturing fluid just during pumping even before proppant is placed in the fracture. This lead to the introduction of encapsulated breakers to help mitigate this effect. Encapsulated breakers are types of breakers that are coated with films which serve as a barrier to active breakers and the fracturing fluid. Due to this, a high concentration of the breakers can be used without having any effect on the viscosity of the fluid during pumping. The active breakers which have been encapsulated can be released through diffusion, osmotic rupture through the barrier. Encapsulation can be done for all variety of breakers. According to Montgomery (2013b), the major demerit of oxidizers is that the rate of their workability depends on the amount of chemical used.

According to Economides & Nolte (2000), there are certain enzymes that belong to the hemicellulase group can act as breakers in reducing the viscosity of water-based fracturing fluid. Enzymes are known from Economides & Nolte to have an advantage because of their bio-catalytic nature. This means enzymes can react with numerous and different guar molecules, therefore the thermal breakdown of polymers can go for a longer period than that of oxidizers. Also, acid can serve as breakers for guar polymers. Fluoride ions can also be used as breakers at low pH to dissolve crosslinks of titanate or zirconate fluids. Montgomery (2013b) added that when the effective breaker is not used it can result in damage to the proppants and decrease the productivity index.

2.6.4 Fluid loss additives

Harris (1988) explained that the fluid-loss-control additive is essential to keep the fracturing fluid in the fracture. When fluid is leaking out of the fracture into the rock matrix, it reduces the rate of propagation of the fracture. As the fluid oozes out of the fracture, the concentration of the proppant increases in the fracture and forms a bridge and propagation of fracture stops.

Economides & Nolte (2000) suggested that proper fluid loss additive can be selected based on the specific fluid loss problem. The problem can be fluid loss to a low or high permeability matrix or loss to microfractures. Silica flour is known from Economides & Nolte to be one efficient fluid loss control additive which helps in building a filter cake. Economides & Nolte reported that, experimentally, silica flour decreased the spurt loss of a 5 to 100 mD rock by 10-folds. The authors reported that it has been proven that, the ability of a fluid loss additive such as silica flour to prevent fluid loss depends on its ability to reach the wall of the rock and remain without been shear off the surface of the rock. This mechanism can be expressed in the form:

$$\frac{F_y}{F_x} \sim \frac{q_l}{d\tau_w}$$

Where: F_y is the force driving the particle toward the wall, F_x is the shear force driving the particle tangentially to the wall, $q_{l,}$ is leak off flux towards the wall and τ_w is the shear stress of the fluid along the wall.

Another, fluid loss additive discussed by Economides & Nolte is starch. Starch is a polysaccharide derived from carbohydrates such as potato, maize, etc. The soft nature of starch aids in the deformation of it under pressure and stress to form low permeability filter cakes to prevent fluid loss. Notwithstanding, this property can be a disadvantage when starch is used for a formation with bigger pore throat. In this case, it passes through the pore throat without any reduction in the spurt loss. Well sized oil-soluble resins with a suitable thermal softening point can also be used as a fluid loss additive. This type of additive is expensive as compared to starch and silicon flour. Because of its solubility in oil, there is minimal formation or proppant damage. Dispersed fluids such as oil in water can also be a mechanism to prevent fluid loss. The dispersed droplets are able to block pores throats in low permeability formation.

2.6.5 Surfactants

Harris (1988) described surfactants as chemicals that help reduce interfacial tension thereby reducing capillary pressure. Reducing the capillary pressure results in a decrease in pressure which causes an easy flow back of fracturing fluid. Also when the pressure in the reservoir is too low, the addition of gases such as CO and nitrogen helps in the easy flow back of the fracturing fluid. Another advantage of these gases is that they expand that aid in the recovery of fluid. The high gas content of surfactant can be used in foams. Foams serve as good fluid for proppant transportation because of its high viscosity. Low gas content in foam also aids in the minimization of formation damage. Surfactant aids in assistance of compatibility problem that may be encountered between the fracturing fluids and reservoir fluids. Addition of the suitable non-emulsifying surfactant prevents potential emulsification between aqueous fracturing fluid and reservoir oil. Economides & Nolte (2000) explained surfactant as "a surface-active agent, or surfactant as a material that at low concentration adsorbs at the interface between two immiscible substances". These substances help in the formation of stable bubbles in foams. They are also used in reducing surface tension and for formation conditioning to aid in the effective cleanup of fracturing fluid.

Montgomery (2013b) shortened the primary goals of a surfactant as "to leave the rock surface water wet, act as an emulsion preventer or as a defoamer and reduce the surface tension".

2.6.6 Bactericides

According to Economides & Nolte (2000), bactericides are needed to prevent loss of viscosity in polymer-containing aqueous fracturing fluids. This is to prevent the degradation caused by bacteria. Bacteria are found in these polysaccharides used as thickeners in fracturing fluid because these sugars are food for them. These bacteria diminish the molecular weight of viscofying polymers. When bacteria are introduced into the reservoir, some are able to endure the conditions in the reservoir. The reduce sulfate ions to hydrogen sulfide (H_2S). Substances such as glutaraldehyde, chlorophenates, quaternary amines, and isothiazoline are used as bactericides. These chemicals are not needed in acid-based or oil-based fracturing fluid.

Harris (1988) added that biocides are developed to prevent the growth of both aerobic and anaerobic bacteria in viscosified fluids. Aerobic bacteria are known to have a rapid growth in the warm climatic region and can terminate the viscosity of a tank of viscosified fracturing fluid within a few hours. In hydrocarbon reservoir, the growth of anaerobic bacteria that do not make use of oxygen is very common. Any unintentional introduction of bacteria through a fracturing fluid can cause the production of H_2S.

According to Montgomery (2013b), bacteria also causes the production of a black, slimy "biofilm" that results in the production of water thereby minimizing production. Ultraviolet light can also be used as a form of antiseptic for fracturing water.

2.6.7 Clay Stabilizers

Clay stabilizers are needed in aqueous fracturing fluid because some formation may contain clay materials that can either swell or migrate. Clays are usually found in an aqueous brine environment. If fracturing fluids have low ionic strength as compared to the clays these fracturing fluid come in contact with, it causes a sudden responsive nature in the clay, causing it to either swell or migrate. Due to this, inorganic salts such as KCl, NaCl, NH_4Cl, or $CaCl_2$ are used as in stabilizing these clays. Other forms of clay stabilizers that can be used are polymeric clay stabilizers. These polymers have several cationic groups found at the backbone of the polymer molecule that is used in connecting to the anions found on the clay surface. These polymers are essential in mitigating clay migration.

Economides & Nolte (2000) described clays as fine particles of silicon and aluminum oxide with a particles size of about 2 mm. These clay particles can migrate into pores thereby reducing permeability. Solutions containing 1% to 3% of potassium chloride can be used to prevent swelling of clay and for its stabilization. Tetramethylammonium chloride can also be used as a clay stabilizer. Other chemicals that can also be used for this purpose are quaternary amines and inorganic polynuclear cations such as zirconium oxychloride and hydroxy aluminum. According to Montgomery (2013b), KCl has unique and efficient characteristics to stabilize clay as compared to other inorganic salts such as NaCl, $CaCl_2$, etc.

2.6.8 Stabilizers

Stabilizers are substances to prevent the deterioration of polysaccharide thickeners at temperatures beyond 200 ^oF. Examples of stabilizers used commonly are methanol and sodium thiosulfate ($Na_2S_2O_3$). Sodium thiosulfate is also more effective as compared to methanol as it is able to increase viscosity by a factor of 2 to10 depending on the temperature and the amount of time it has been exposed to the temperature. Though the phenomenon by which stabilizers operate have not been fully understood, it is perceived that stabilizers act as oxygen hunters thereby preventing deterioration of viscosity caused by dissolved oxygen. In stabilizing viscosifiers, the pH of the fracturing fluid is very critical.

2.6.9 pH Controllers

Harris (1988) study shows that pH influences the initial polymer gelation rate, crosslinking properties, viscosity stability, gel break properties, bacteria control, and several other properties. Usually, most fracturing fluids have a pH ranging from 3 to 10. Buffers which are the combination of a weak acid and weak base are used in maintaining pH within a small range so that the required properties of the fluids can be obtained.

2.6.10 Friction reducers

Friction reducers are chemicals that are added to reduce the friction produced as a result of fluid been pumped down the well tubular. There are various types of friction reducers namely: polyacrylic acid, polyacrylamide, partially hydrolyzed polyacrylamide, and acrylamidomethylpropane sulfonate.

2.7 PROPPANTS

Proppants sustain the created conductive path in unconventional formations after the fracturing fluid has leaked off. According to Economides & Nolte (2000), one major determinant in attaining a successful hydraulic fracturing process involves selecting the right type of proppant in its required concentration. Fracture conductivity is defined as the product of fracture width and fracture permeability, and it is influenced by:

- Composition of proppant
- Physical characteristics of the proppant
- Permeability of the proppant-pack
- Generation and movement of formation fine in the fracture
- Degradation periods of the proppant.

The fractures created are acted upon by in-situ stresses from the formations. For a proppant to keep the fractures opened, the proppant must be able to overcome these in-situ stress acting on the fractures to prevent its closure. The permeability and conductivity of the proppant pack decrease when the strength of the proppant is less than the closure stress of the formation causing deformation and crushing of the proppant. This results in the generation of fines which closes the fractures thereby reducing conductivity and productivity (Economides & Nolte, 2000). Due to this, the physical properties of the proppants are keen in determining the conductivity of proppants.

The various type of proppants has their respective strength to closure stress. Economides & Nolte (2000) gave details of closure stress different proppant can withstand.

Table 1-Strength of Proppant

Proppant Type	**Strength of Proppant**
Sand	Closure stresses less than 6000 psi
Resin-coated proppant (RCP)	Closure stresses less than 8000 psi
Intermediate-strength proppant (ISP)	Closure stresses greater than 5,000 psi but less than 10,000 psi
High-strength proppant	Closure stresses at or greater than 10,000 psi

Source: Economides & Nolte (2000)

The figure below shows the permeability and the strength of various types of proppants.

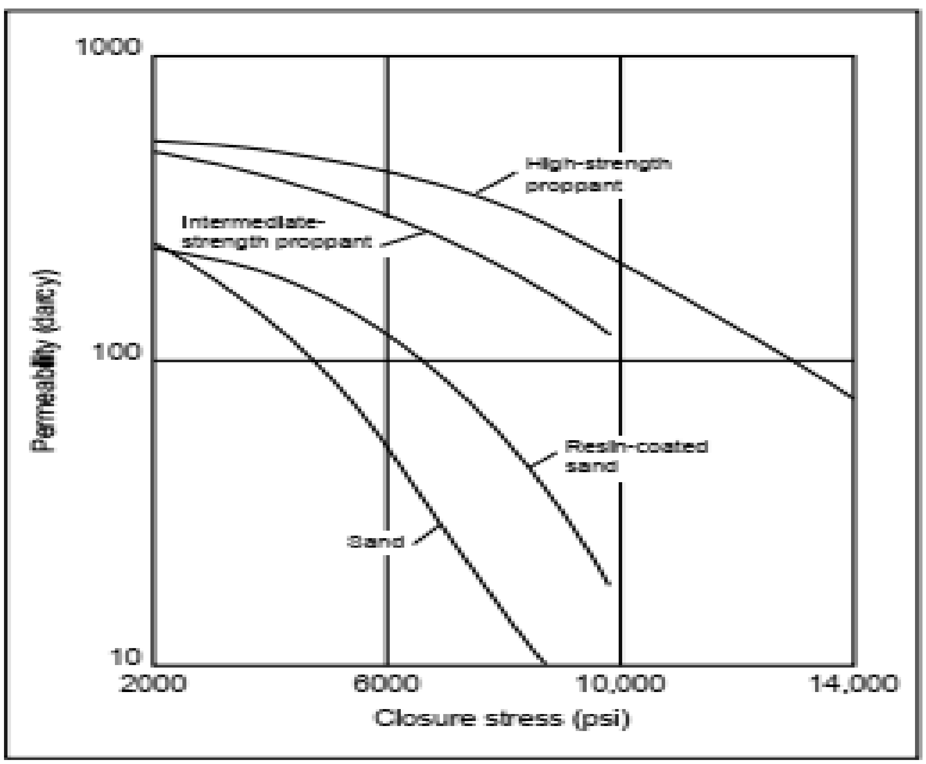


Figure 6-Strength of Proppants

Source: Economides & Nolte (2000)

The size of proppant also influences the permeability of the proppant pack. Larger grain size tends to cause an increase in permeability of the proppant pack as compared to smaller grain sizes however, larger grain of proppants have a lot of difficulty in proppant transportation and placement (Economides & Nolte, 2000; Liang, Sayed, Al-Muntasheri, Chang, & Li, 2016). Also, larger grain sizes create a lot of fines in unconsolidated formations which reduces the permeability of the proppant pack by plugging the created fractures. It is interesting that the average conductivity of smaller proppant throughout the life of the well is far higher than the conductivity of larger proppants. Larger proppants have a higher conductivity at the initial stage of production but decreases drastically throughout the life of the well (Economides & Nolte, 2000).

Liang et al. (2016) reported an experiment originally performed by Schmidt et al. which explains that blending of proppant of different sizes has the capability to reduce the permeability of the proppant pack, however, tail in of proppants of varying sizes results in higher conductivity.

Proppant roundness is the measure of the angularness of the edges and corners of the proppant grain. Proppant sphericity is also a measure of how closely the grain resembles a sphere. The roundness and sphericity contribute to the conductivity of the fracture. For grains of equal size and roundness, there is a fair distribution of the stress applied on the proppant as compared to angular grains which produce a lot of fines when the closure stress increases thereby reducing the overall permeability and conductivity (Economides & Nolte, 2000).

The density of the proppant determines the settling rate of the proppant in fracturing fluids. For a high-density proppant, a highly viscous fracturing fluid or higher injection rate is needed to reduce the settling rate and ensure suspension of the proppant in fracturing fluid to transport the proppant into the fractures.

2.7.1 Types of Proppants

2.7.1.1 Sand

Sand proppant is made up of graded high-silica content quartz (Liang et al., 2016). This type of proppant is widely used throughout the world due to its affordability and ready supply on the market. Sand has a specific gravity of about of 2.65 and can withstand closure stress less than 6000 psi. Sand can be grouped into classes based on their physical characteristics. They are Northern white sand, Texas brown sand, Colorado silica sand and Arizona silica sand (Economides & Nolte, 2000). There are two major types of sand based on their level of impurities, they are white sand and brown sand. The white sand is low in impurities as compared to the brown sand which has a high level of impurity. White sand also has a high silica content as compared to that of brown sand. Brown sand is far cheaper than white sand due to its level of impurity (Liang et al., 2016).

2.7.1.2 Resin-coated proppant (RCP)

This type of proppant is sand coated with resin. This type of proppant has the ability to withstand closure stress less than 8000 psi. Resin-coated proppant (RCP) has an advantage over the conventional sand. In the case of crushing, RCP encapsulates the fine produced which mitigates issues of plugging and reduction of permeability in proppant pack. The resin coat also aids in the dissemination of the forces applied to proppant (Economides & Nolte, 2000; Liang et al., 2016).

Precured-resin-coated proppants are types of RCP that are cured to form a non-melting, inert lining to improve the strength and capability of the proppant thereby aiding in withstanding high in-situ stresses. Precured-resin-coated proppants helps to curb flowback of proppants near wellbore (Economides & Nolte, 2000).

Notwithstanding the advantages of RCP, Economides & Nolte (2000) highlighted some of the adverse effects of RCP. It is said that resin-coated proppants serve as interference with the activities of some additive such as organometallic crosslinkers, buffers, and oxidative breakers.

The RCP can interfere with the crosslinking activity of organometallic crosslinkers, increase the consumption of oxidative breakers which reduces the cleaning efficiency of the breakers and reduces the permeability of proppants by compromising the binding activity of the proppant with each other to form a permeable proppant pack. Failure to bond can cause flow back of proppant and crushing.

Another disadvantage of RCP is the inability to withstand high temperature since its resin coat is made of polymers that deteriorate quickly as compared to inorganic material. There are various types of resin that can use. Examples are epoxy resins, furan, polyesters, vinyl esters, and polyurethane. Epoxy is the most used resin for proppant coating, it is noted for its good mechanical strength, excellent heat resistance, and chemical resistance. Polyurethane also has good mechanical strength and good heat and chemical resistance when the temperature is below 250 °F. Furan can also be used for coating but has a limitation of low mechanical strength (Liang et al., 2016).

2.7.1.3 Ceramic

This type of proppant is manufactured from sintered bauxite, kaolin, magnesium silicate, or blends of bauxite and kaolin. It has high strength than sand and also has an evenly distributed grain size, roundness, and sphericity which aid in increasing porosity and permeability. Ceramic proppant has the highest thermal and chemical stability among all the proppants. It is more costly than any brand of proppant. Ceramic proppant is divided into three categories based on their density and silica content. They are lightweight ceramics (LWC), intermediate density ceramics (IDC) and high-density ceramics (HDC). The alumina content in the ceramic proppant is directly proportional to the strength of the proppant and its density(Liang et al., 2016).

The table below gives the alumina content and the specific gravity of the type of ceramic proppants.

Table 2 - Alumina content and specific gravity for different grade of ceramic proppant

Ceramic proppant	Alumina content (%)	Specific gravity (S. G)
Lightweight Ceramics (LWC)	45 to 50	2.55 to 2.71
Intermediate Density Ceramics (IDC)	70 to 75	~3.2
High-Density Ceramics (HDC)	80 to 85	~3.5
Ultra High Strength Proppant (UHSP)	Nearly 100	~3.9

Source: (Liang et al., 2016)

Intermediate -strength proppant (ISP)

ISP can be fused-ceramic of low-density or sintered-bauxite of medium-density with a specific gravity of 2.7 to 3.3. The sintered-bauxite proppant is made from bauxite-rich in mullite. ISP can withstand closure stress of greater than 5,000 psi, but less than 10,000 psi.

High-strength proppant

This is a sintered-bauxite made from bauxite ore rich in corundum with a specific gravity of 3.4. This type of proppant can withstand closure stress greater than 10,000 psi and the most expensive among the proppants.

2.7.1.4 Lightweight proppant

The specific gravity of most proppant is within the range of 2.65 and 3.9. This range of specific gravity is greater than the carrier fluid which mostly has a specific gravity of 1 for freshwater and 1.2 for brine. Due to this, there is a likelihood of settling because of the difference in specific gravity. Hence, to aid the suspension of proppants, fluids of higher viscosity has to be used if proppants of higher densities are chosen this means the overall cost of the fracturing treatment is increased. Using high-density proppants also result in smaller fracture volume for a particular weight of proppants. This issue has led to research works geared toward the manufacturing of low-density proppant that can easily be carried by slickwater. This resulted in the manufacturing of proppants with lower density material such as walnut shells, pits, and husks. However, proppant made from these materials might have low strength and cannot withstand high closure stress. Other lightweight proppants such as resin-coated porous ceramic proppants and some form of ultra-lightweight (ULW) propping agents have designed and investigated (Liang et al., 2016).

2.7.2 Functions of Proppants

Apart from the traditional function of proppants which is to maintain the conductive path of fractures, there are other auxiliary and advanced functions of proppants. Below are some few (Liang et al., 2016).

- Traceable proppants that are used to monitor the extent of fracturing treatment using radioactive elements.
- Porous ceramic proppants are also used in the slow release of solid scale inhibitor in wells.
- Proppants also serve a means of releasing breaker in wells.
- Proppants can also help in removing contaminants in wells.

2.7.3 Selection of Proppants

To select a proppant for fracturing activity, the closure stress of the formation, specific gravity and cost of proppants and strength of proppant to changes in stress should be taken into consideration. The net present value (NPV) of the proppant choice should be performed to analyze its profitability with respect to that particular well. For brittle rocks, fracturing can be done more easily than ductile rocks. For brittle rocks, slickwater and hybrid fracturing treatment fluid systems can be used to create complex fracture connection. For ductile rocks or shaly reservoir formations, the use of viscous fluid is required to create the conventional bi-wing fracture system (Liang et al., 2016).

It is difficult to transport high-density ceramic proppant with slickwater. Low viscous fluid has a disadvantage of carrying proppants to only the fracture tips. The hybrid form of proppant selection can also be used where different types and sizes of proppants are blended together or tail-in of different size and type is used depending on the viscosity and the type of treatment approach. To choose a type of proppant for a fracturing activity there should be a balance between the fracture flow capacity (FCD) and cost. A longer and more conductive fracture is more productive than a smaller and less conductive fracture. However, there should be a correlation between the length and the cost. It has been known that the cost of proppants accounts for about 10-20% of the total treatment cost for a small sand proppant treatment design while the cost of proppant for a large treatment process using synthetically manufactured proppants can go beyond 50% of the total treatment. The net present value, the internal rate of return and the payoff time should be considered when selecting proppant (Liang et al., 2016).

The table below shows the cost of proppants.

Table 3-Price of the various Proppants

Proppant Price	**Price, $ per lb**
Sand	0.019 to 0.058
RCS	0.195 to 0.245
Ceramics	0.27 to 0.90

Source: (Liang et al., 2016)

2.8 METHODS OF SELECTING ADDITIVES

Montgomery (2013b) stated that the selection of materials for fracturing fluids is difficult and uncertain and can be confusing for a practicing hydraulic fracturing engineer. Harris (1988) gave some suggestions on selecting additives. It is often necessary to have information about core samples or formation fluid before additives are chosen.

H Xiong & Holditch (1995) proposed to apply fuzzy logic to aid in additive selection, and this method functions well when little information about the formation to design. The fuzzy logic method designed by the authors first select the type of fracturing fluid and then select the specific additive to aid attain the designed properties.

S. a Holditch, Xiong, Hoiditch, & Rueda (1993) proposed a computer-based model for selecting fracturing fluid and additive on the basis of knowledge gained from experts in fracturing treatment through the administration of questionnaires and through literature review. The model also performs economic analysis based on reservoir performance.

2.9 CONCLUSION

Most of these computerized selection methods are almost inaccessible to all and sometimes very difficult to understand. Also, in finding the right additives for hydraulic fracturing process, most research works consider the case studies on a number of wells in a particular field and test the effectiveness of the various additives and fracturing fluids on whole fracturing process. Though this type of project aid in understanding the effectiveness of various fracturing treatments, there is the need for a research work that studies fracturing treatment across many formations and regions to serve as a guide to engineers on the best practices.

CHAPTER 3

METHODOLOGY

3.1 INTRODUCTION

This chapter presents the research approach used for this project. Selection of the right hydraulic fracturing fluids and proppants determines the success of the fracturing process. This necessitates the studying of the various fracturing fluids and proppants used in various formations to aid in establishing a relationship between the type of fracturing treatment and its corresponding formation characteristics for the best practices that can boost production. To attain this purpose three of the major plays in the United States were studied. These formations are unconventional reservoir formations that have contributed to the 'shale boom' in the United State during these recent years.

3.2 FRACFOCUS

Data used for this research were gathered from "fracfocus". Fracfocus is national hydraulic fracturing chemical registry that has a database of all the chemicals and additives used for hydraulic fracturing in the United States. This database is managed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. The main motive of the site is to provide the public access to concrete and factual information regarding chemicals and additives used for fracturing in their area. Though this site does not fall into any governmental information system, it is used by about twenty-three states as their means of official state chemical disclosure. The record has some relevant elements that give information about the well. The figure below is a section of the record of a particular well from fracfocus.

Hydraulic Fracturing Fluid Product Component Information Disclosure

Job Start Date:	11/3/2016
Job End Date:	11/3/2016
State:	Texas
County:	Harrison
API Number:	42-203-32148-00-00
Operator Name:	Sheridan Production Company, LLC
Well Name and Number:	Bell A-5
Latitude:	32.45111500
Longitude:	-94.15096300
Datum:	NAD27
Federal Well:	NO
Indian Well:	NO
True Vertical Depth:	9,700
Total Base Water Volume (gal):	207,047
Total Base Non Water Volume:	0

Figure 7-Well Data from Fracfocus

From the figure shown, the date for the start of the fracturing job, date for end of the job, the state where the well is located, the well name, the country where the well is found, true vertical depth, total base water volume, and total base non-water volume and all other forms of indexing are all shown.

Apart from the information shown above, additional information about the various chemicals used for fracturing treatment is also provided. This includes the trade name of the chemicals used, the individual ingredients that make up the additive, ingredient concentration in hydraulic fracturing fluid percentage by mass, ingredient concentration in additive percentage by mass and chemical abstract Service or CAS Number. The ingredient percentage in additive by % mass describes the mass of the particular ingredient within that additive expressed as a percentage. Ingredient concentration in hydraulic fracturing fluid % by mass also expresses the amount of that particular ingredient as a percentage to the total mass of the hydraulic fracturing fluid which includes the base fluid and the additives. The CAS number serves as a means of identifying particular chemicals assigned by the American Chemical Society.

In finding the relationship between fracking treatment and its formation properties, some data of fracked wells in the year 2015 were selected. The formations considered were Bakken, Haynesville, and Barnett. The table below shows a list of the formations, states, and countries selected for this research.

Table 4-Data Classification

Formation	Number of Wells Used	State	Country
Bakken	75	North Dakota, Montana	Richland, William, Roosevelt, Burke, Divide, Wibaux, Dawson, McKenzie, Mountrail, Billings
Haynesville	75	Louisiana	Bossier, Caddo, Desoto, Red River
Barnett	50	North Texas	Wise, Tarrant, Parker, Jackson, Denton
Marcellus	100	Ohio, Pennsylvania, West Virginia, Virginia	Harrison, Jefferson, Monroe, Belmont, Carroll, Guernsey, Columbia, Allegheny, Bradford, Butler, Fayette, Greene, Lawrence, Lycoming, Mercer, Wetzel, Susquehanna, Tioga, Washington, Tyler, Taylor, Ritchie, Marshall, Doddridge, Dickenson, Wyoming
Eagle Ford	100	Texas	Webb, Brazos, Atascosa, Gonzales, Madison, Walker, Maverick, Grimes, Milam, Lee, Fayette, Lavaca, Bee, DeWitt, Live Oak, La Salle, Zavala, Dimmit, Karnes

3.3 CLASSIFICATION OF DATA

As explained earlier in chapter two of this document, there are several types of fracturing fluids and additives. A fracturing fluid is a composition of the based fluid, additive and propping agent.

After the relevant information needed was collected from the fracfocus database, the data was then classified and analyzed based on the chemicals used for a particular fracturing treatment. An algorithm was created using python and data analysis was done using Microsoft Excel and pandas.

3.3.1 Classification of Fracturing Fluids

The tables below show the fracturing fluid classification and proppant classification used for the project.

Table 5-Frac Type Classification

Frac Type	Classification Definition
Hybrid	Water-based fluid + gelling agent + cross-linker+ friction reducer or Water-based fluid + gelling agent + friction reducer
Slickwater	Water-based fluid + friction reducer
Linear	Water-based fluid + gelling agent
Crosslinked	Gelling agent fluid + cross-linker + water
Others	Secondary Frac Types such as Acid Fracs, Energized Fracs, and any other frac types identified that does not fall in the above groups

3.3.2 Classification of Proppants

Proppants selection is also an integral part of a fracturing process, especially for unconventional formations. Because of this, proppants used for the fracturing of the selected wells were also grouped into three main categories. These categories are sand, resin-coated sand, and ceramics. The table below shows the classification of the proppants made for the selected wells.

Table 6-Proppant Classification

Proppant Type	**Definition**
Sand	Comprises of all raw frac sand types, including Northern White, Ottawa, Brady, Brown Sand, Texas Gold, etc.
Resin-Coated Sand	Comprises of resin-coated proppants for which the substrate is sand.
Ceramic	Any proppant for which the substrate is a ceramic

Because most of the wells collected used more than one form of proppant for their fracturing process, the proppant classification was grouped further into the possible proppant combination possible. The table below shows this classification.

Table 7-Proppant Type

Proppant Design	**Definition**
Sand Only	A well that contains only raw sand.
Sand+RCS + Ceramic	A well that contains sand, resin-coated sand, and ceramic proppant.
Sand + RCS	A well that contains sand and resin-coated sand.
Sand + Ceramic	A well that contains sand and ceramic proppant.
RCS Only	A well that contains resin-coated sand only.
RCS + Ceramic	A well that contains resin-coated sand and ceramic proppant.
Ceramic Only	A well that contains ceramic proppant only.

3.4 OBSERVED RELATIONSHIPS

After classification and studying both the trend of fracturing fluids and proppants, detailed analysis of why those fluids were used in the Barnett, Haynesville and Barnett formations and their relation to their formation characteristics are explained in the next chapters.

CHAPTER 4

CHARACTERISTICS OF BAKKEN, HAYNESVILLE, AND BARNETT FORMATIONS.

4.1 INTRODUCTION

Economides & Nolte (2000) defined rock mechanics as “the theoretical and applied science of the mechanical behavior of rock; it is that branch of mechanics concerned with the response of the rock to the force fields of its physical environment.” The ability to drill into a reservoir rock is governed by the fragmentation of the rock, however, its mechanical behavior determines the means of completion, stimulation, and production. In the early days as deeper wells were being drilled and completed, borehole collapses and instabilities became more pronounced. These instabilities were as a result of large tectonic forces.

Rocks have the ability to withstand stresses up to a particular point when these critical points are exceeded, there is a likelihood of collapse for the rock formation. Due to this core and log samples are not only used for the finding porosity and permeability but also to determine the mechanical properties of rocks (Economides & Nolte, 2000).

4.1.1 Stress

Stress is simply the force per unit area of a unit. The stress vector can be defined as:

$$\sigma = \lim_{\Delta A \to \infty} \left[\frac{\Delta F}{\Delta A}\right]$$

Where σ, ΔA and ΔF are the stress vector, area, and resultant force respectively.

Economides & Nolte (2000) also reported a concept originally introduced by Hubbert and Willis (1957) which states that “the general state of stress underground is that in which the three principal stresses are unequal. For tectonically relaxed areas characterized by normal faulting, the minimum stress should be horizontal; the hydraulic fractures produced should be vertical with the injection pressure less than that of the overburden. In areas of active tectonic compression and thrust faulting, the minimum stress should be vertical and equal to the pressure of the overburden. The hydraulic fractures should be horizontal with injection pressures equal to or greater than the pressure of the overburden". Another concept highlighted is that fractures created should be in the region perpendicular to the axis of minimum principal stress. The direction of minimum stress should also be related to the depth of formation.

4.1.2 Strain

The strain is defined as the ratio of the change in length or angle of a body in response to the stress applied to a body causing its deformation. Strain can be two categories they are elongation and shear strain. Elongation is the ratio of change in length while that of shear strain is the change of angle between two directions which were initially perpendicular to each other before straining begun (Economides & Nolte, 2000).

$$\varepsilon = \lim_{l \to 0} \frac{l - l^*}{l}$$

Where, ε = elongation, l = initial length and l* = length after strain

$$\gamma = \tan(\psi)$$

Where, γ = shear strain

ψ = angle in the angle between two directions after the stress is applied (Economides & Nolte, 2000).

4.1.3 Linear Elasticity

There is a relationship between stress and strain on rocks. The higher the stress, the higher the level of deformation and the higher the resultant strain. The theory of elasticity establishes a linear relationship between stress and strain. This introduces the idea of Young's modulus (E). The Young's modulus is the coefficient of proportionality between the stress and the strain under uniaxial compression situation which causes a sample to shorten under the applied force (Economides & Nolte, 2000). The relation which introduces Young's modulus is given below:

$$\sigma = E\varepsilon$$

The Young's modulus measures the stiffness of the rock. The higher Young's modulus the stiffer the rock and the higher its brittleness. The lower Young's modulus, the lower the stiffness of the rock and the more ductile the rock is. Brittle rock is mostly the target for hydraulic fracturing designs because it produces superior completion quality (Ma, Sobernheim, & Garzon, 2015). The Young's modulus gives an indication of the fracture conductivity to expect (Akrad, Miskimins, & Prasad, 2011). The Young's modulus also indicates how well the rock can maintain the fracture once it is done (Rickman, Mullen, Petre, Grieser, & Kundert, 2008).

The Poisson's ratio (v) measures "the ratio of lateral expansion to longitudinal contraction" (Economides & Nolte, 2000). The Poisson's ratio is defined "as the fraction of expansion divided the fraction of compression". The Poisson's ratio helps in determining the closure stress (Ma et al., 2015). The Poisson's ratio is the measure of the strength of the rock. Rocks like sandstone have Poisson's ratio of about 0.1 – 0.3 which indicate how easily these rocks can be fractured. Shales and coal have Poisson's ratio ranging from 0.35 to 0.45, which indicate the extent of their elasticity and how hard it is to fracture them (Crain, 2002).

A combination of the Poisson's ratio and Young's modulus gives the brittleness of a formation. The Brittleness Index can be used to determine the brittleness of a rock formation. Very brittle rocks have high Young's modulus and vice versa for ductile rocks. Ductile shale does not make good reservoir rocks because they quickly heal every fracture that is made through them. However, ductile rocks are good seals that prevent the migration of hydrocarbons in the brittle shale below. Brittle rocks are good for hydraulic fracturing and are mostly natural fractured (Rickman et al., 2008).

Knowing the characteristics of the formations under consideration is very essential. Thompson et al. (2009a) highlighted that "the mechanical properties of the rock and the stress regime will provide an indication as to how the rock will respond to drilling, hydraulic fracturing, and production". Thompson et al. (2009a) added that rocks with higher unconfined compressive strength, higher Young's Modulus and low Poisson's ratio exhibits a higher rate of penetration during drilling activities. Rickman, Mullen, Petre, Grieser, & Kundert (2008) summarized some necessary factors to consider in the selection of proppants and hydraulic fracturing. Prominent of these factors is to determine the brittleness and closure pressure of the formation to aid in fluid and proppant selection.

4.1.4 Brittleness Estimation

Several empirical formulae have been developed by several authors for the calculation of for brittleness.

- The simplest of these equations is the ratio of Young's modulus to the Poisson's ratio, $E/_{v}$ (Belyadi, Fathi, & Belyadi, 2017).
- Another formula used in calculating the brittleness which makes use of the average values of the parameters is shown.

$$BI\ (\%) = 0.5\left(\left(\frac{E - Emin}{Emax - Emin}\right) + \left(\frac{v - vmax}{vmin - vmax}\right)\right)$$

Where BI = Brittleness Index, E is the Young's Modulus, Emin and Emax are the minimum and maximum Young's Modulus values in the studied area, v is the Poisson's Ratio and V_{max} and v_{min} are the minimum and maximum Poisson's Ratio values in the studied area (Wescott et al., 2014).

- Rickman et al. (2008) also develop another equation to determine brittleness. The equation is shown below.

$$Brittleness\ Index\ (\%) = \frac{\left(\left(\frac{E_{static} - 1}{7}\right) \times 100\right) + \left(\left(\frac{v - 0.4}{-0.25}\right) \times 100\right)}{2}$$

Where E_{static} is the Elastic Young's Modulus and v is the Poisson's ratio

- Brittleness can also be determined from the mineralogical composition of the formation. The quartz content in the formation determines how brittle the rock formation would be. The formula for this is shown below:

$$Brittleness\ Index(\%) = \frac{Quartz\ content}{Quartz\ content + Calcite\ Content + Clay\ Content}$$

4.1.5 In-situ Stresses and Pressure

The in-situ stress is made up of three principal stresses acting perpendicularly to each other. These stresses are overburden stress, maximum horizontal stress, and minimum horizontal stress (Ma et al., 2015). A critical pressure in the design of hydraulic fractures is the minimum horizontal stress (Crain, 2002). This is because fractures created should be in the direction perpendicular to the minimum horizontal stress. If the rock formation is subjected to normal faulting, the fracture created should be vertical, however, for an active thrust fault, the fractures created should be horizontal (Economides & Nolte, 2000).

Fracture Pressure is defined as "the pressure needed to create a fracture in a rock while drilling in the open hole" (Crain, 2002). Closure stress is also defined as the "pressure at which the fracture closes after the fracturing pressure is relaxed" (Crain, 2002). The closure pressure is estimated to be 80 and 90% of breakdown pressure. The breakdown pressure is the summation of the closure stress and the frictional pressure caused by the fracturing fluids introduced into the formation for fractures to be created. The closure and fracture pressure are a function of the overburden pressure, pore pressure, Poisson's Ratio, porosity, tectonic stresses, and anisotropy (Crain, 2002). The figure shows the various pressure considerations used in fracturing design.

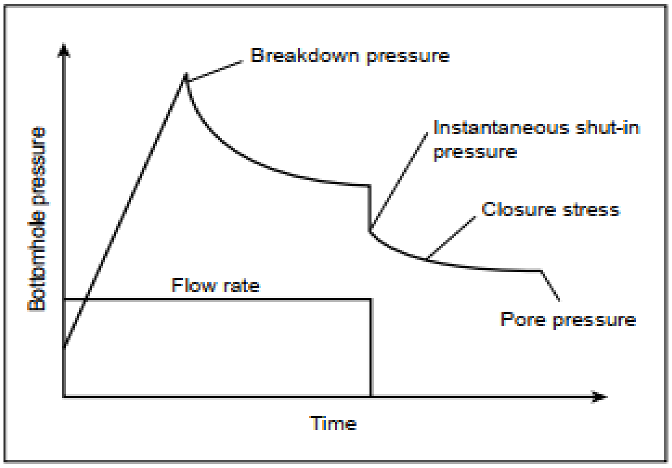


Figure 8-Pressure Terminologies used in Fracturing

(Economides & Nolte, 2000)

It should be noted that only a portion of the total stress is carried by the rock matrix. The pore pressure also contributes to the total stress. Therefore the total stress applied on a rock mass is the summation of the pore pressure and the effective stress carried by the grains or matrix.

4.1.5.1 Closure Pressure Estimation

The closure stress on proppant is approximately equal to the minimum horizontal stress (Belyadi, Fathi, & Belyadi, 2017; Economides & Nolte, 2000; Terracina, Turner, Collins, & Spillars, 2011). The equation for determining the minimum horizontal stress is shown below.

$$\sigma_{h,min} = \frac{v}{1-v} \times (\sigma_v - \alpha P_P) + \alpha P_P + P_{Tectonic}$$

Where $\sigma_{h,min}$ is the minimum horizontal stress, v is the Poisson's ratio, σ_v is the overburden stress, α is the Biot's constant, P_p is the pore pressure and $P_{Tectonic}$ is the Tectonic Stress.

Another equation called the Barree Model can also be used to determine the closure stress (Crain, 2002; Rickman et al., 2008). The Barree Model is stated below.

$$Closure\ Stress = \left(\frac{v}{1-v}\right) \times (\sigma_v - (\alpha P_P) + P_P + Strain\ Constant \times E + P_{Tectonic}$$

Where v is the Poisson's ratio, σ_v is the overburden stress, α is the Biot's constant, P_p is the pore pressure and $P_{Tectonic}$ is the Tectonic Stress.

4.2 BAKKEN FORMATION

The Bakken formation was discovered in 1953 (Tran, Sinurat, & Wattenbarger, 2011). The Williston Basin in which the Bakken is found is oval in shape with a surface area ranging from 120,000 to 240,000 square miles (Zeng & Jiang, 2013). The formation extends from Canada to the United States in the regions of North Dakota South Dakota, Montana, and Saskatchewan (Tran et al., 2011). The Williston Basin stretch between the areas of North Dakota, western Montana, northwestern South Dakota, and southeastern Saskatchewan and extend to a portion of southwestern Manitoba.

4.2.1 Geology and Geochemical Properties of the Bakken Formation

The rocks found in the basin are sedimentary rocks within the Cambrian through Quaternary ages. The basin has its highest depth in North Dakota with a rock column greater than 15,000 ft thick in its deepest section (Zeng & Jiang, 2013). Below the Bakken formation is the Three-Fold formation (Fry & Paterniti, 2014). The figure below shows the Williston Basin and the Bakken petroleum system.

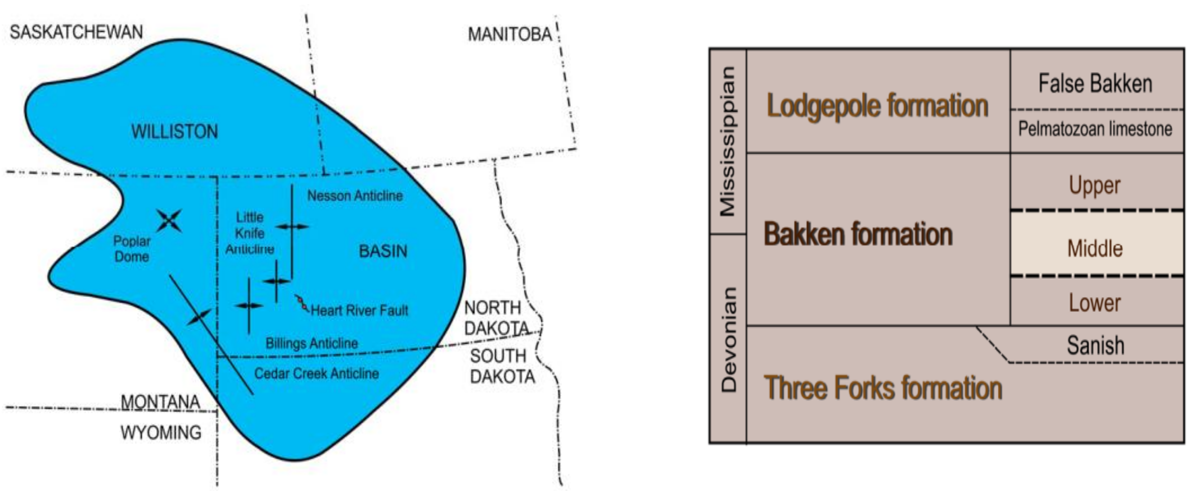


Figure 9-The Williston Basin **(Zeng & Jiang, 2013)**

The Bakken has a series of individual formations. The upper Lodgepole formation, the Bakken itself and the underlying Three Forks formation. The Three Forks is known for its unique reservoir characteristics. The upper Three Forks has the best reservoir properties in the Bakken System. The upper Three Forks is made up of two lithofacies: silty to sandy dolostone that is generally low in clay and finely laminated green mudstones and dolomitic siltstones. The middle Three Forks is made up of dolomitic mudstone and siltstone and forms a minor reservoir interval in the Bakken petroleum system. The lower Three Forks is also made up of finely laminated, silty, dolomitic claystone and anhydrite. The lower Three Forks is not part of the Bakken Petroleum System due to its low permeability and vertical separation from the shaly source rocks of Bakken (Hamlin, Smye, Dommisse, Eastwood, & McDaid, 2018).

The Upper and Lower Bakken which are the source rocks of the Bakken petroleum system and are very similar in composition. The shales in this formation have a high content of uranium accompanying the rich organic matter. The upper and lower Bakken are rich in silica ranging from about (40-70%). The silica in this part of Bakken is primarily quartz, silt, and biogenic silica. The Bakken also has a clay content ranging from 20-40%. The upper and lower Bakken also has a large quantity of sulphidic minerals in the form of pyrite. The major mineralogical content found in the Bakken is feldspar, dolomite, and calcite. The lower Bakken is also made of a silt component which has a high amount of clay (Hamlin et al., 2018).

The middle Bakken serves as part of the formation prominent for acting as the reservoir. According to Hamlin et al. (2018), the middle Bakken is sectioned into six namely: “fine-grained fossiliferous limestone, clay-rich siltstone, laminated sandstone/siltstone, calcareous sandstone, laminated dolomitic siltstone, and bioturbated limestone/siltstone”. The Laminated sandstone/siltstone is the best reservoir interval (Hamlin et al., 2018).

The Lodgepole Formation which overlies the Bakken serves as the trap to prevent migration of hydrocarbons from the Bakken Shales. It is about 900 ft. thick. The Scallion Limestone is the base of the Lodgepole Formation. There is a calcareous black shale that lies on top of the Scallion Limestone. This shale is known as the “False Bakken”. The False Bakken has an organic content similar to that of the Bakken Formation (Hamlin et al., 2018). The mineralogy of the lower and middle Bakken is shown below.

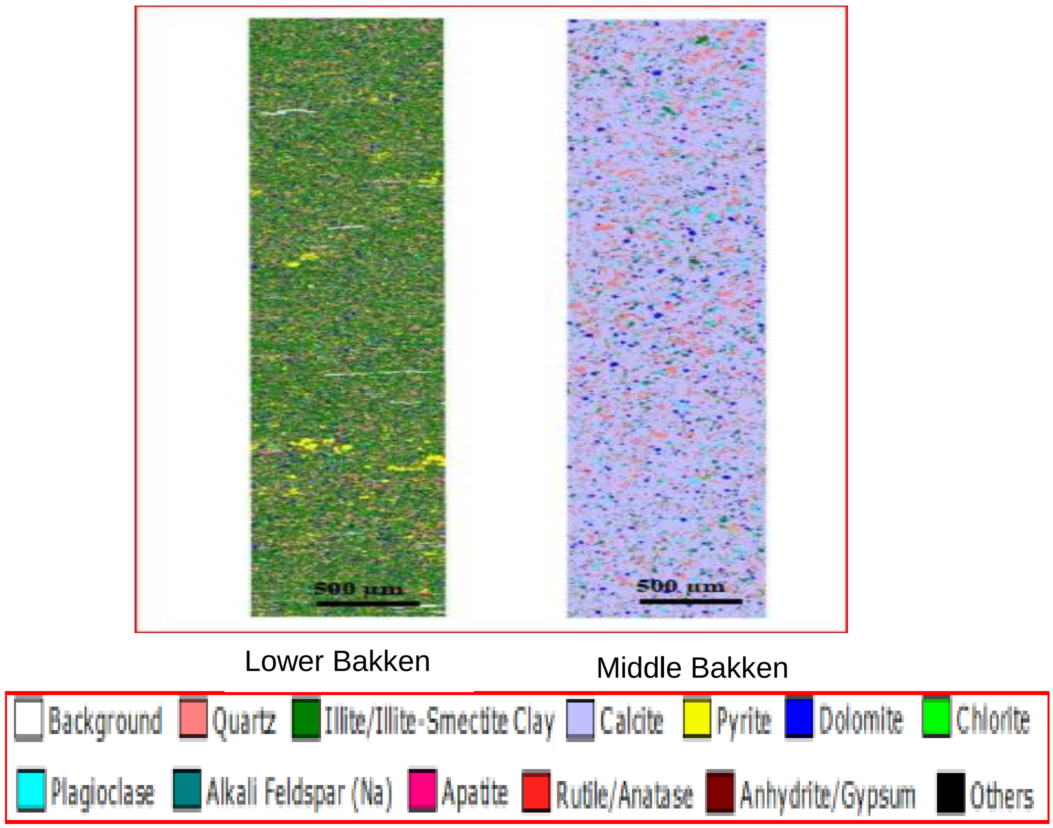


Figure 10- Mineralogical Composition of the Bakken formation (Akrad et al., 2011)

The Bakken formation is very thin with a maximum thickness of about 145 ft. The Bakken is a naturally fractured formation within the Upper Devonian Lower Mississippian ages. The upper and lower portions of the formation are the source rocks rich in oil and gas for the formation and are shales with high organic contents. The middle section of the formation is interbedded siltstones and sandstones with a maximum thickness of 85 ft at depth of 9500 and 10000 ft (Zeng & Jiang, 2013). Notwithstanding, the thinness of the Bakken formation, is highly rich in organic content and among the world’s richest hydrocarbon formations.

The Bakken is known to have an estimated oil original oil in place (OOIP) ranging from 200 to more than 400 billion barrels (Zeng & Jiang, 2013). The lower and upper part of the Bakken formation, rich in organic content can have as high as 36 % of total organic content while the middle part has a total organic content as low as 1 % (Tran et al., 2011). The Bakken is an oil-prone formation consisting of Type 2 kerogen. The upper and lower Bakken has a thickness ranging from 0.5 to 46 ft., with a depth of about 9000 ft. with a permeability of about 0.01 to 0.03 millidarcy. The temperature of the formation also ranges from 70 to 140˚C which falls within the oil window (Tran et al., 2011). The middle section of the Bakken formation serves as the reservoir rock to contain the hydrocarbon and has a permeability of 0.0003 to 3.36 md (Tran et al., 2011).

Natural fractures in the Bakken is as a result of overpressure caused by the generated hydrocarbon which helps in attaining a higher effective permeability through the interconnected fractures (Tran et al., 2011).

The Bakken formation is an oil-wet formation. Acidizing in Bakken is forbidden. This is because the mineralogical composition of the formation has a high pyrite content in the shale. This causes the formation of an iron hydroxide precipitate with acids (Zeng & Jiang, 2013).

The lower Bakken is predominately made of water-sensitive illite-smectite clay while that of the middle Bakken is made of predominate calcite (Akrad et al., 2011).

Production from Bakken is concentrated in the western North Dakota and Western Montana. The Bakken behaves as both a conventional and unconventional formation. This is because it has a distinct source rock and reservoir units. Just a little amount of hydrocarbon has been produced from the dirty shale in upper and lower Bakken. The middle Bakken and Three Forks serve as the low permeability reservoir zones where most of the hydrocarbons from the Bakken have been produced (Hamlin et al., 2018). The figure below shows the regional extent of the Bakken Unconventional Formation.

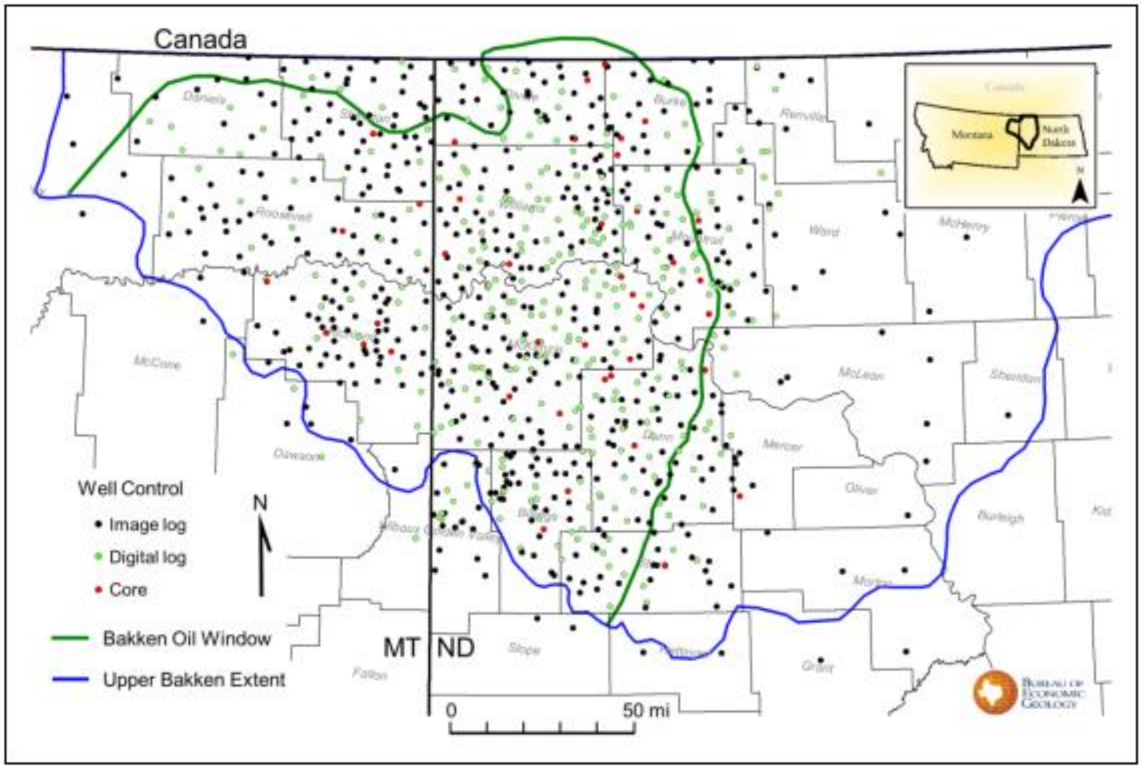


Figure 11- Location of the Bakken Petroleum System

(Hamlin et al., 2018)

From the figure, it can be seen that the unconventional Bakken Petroleum system matches with the Bakken Oil window that is, the thermal maturity area.

4.2.2 Rock Mechanical Properties of Bakken

The in-situ-stress and geomechanical properties of the Bakken is quite complicated due to the variation of stresses from one location to the other (Zeng & Jiang, 2013).

The two most important parameter needed to estimate the rock characteristics of any formation are Young’s modulus and the Poisson’s ratio. A study of the Bakken formation by He, Ling, Wu, Pei, & Pu (2019) analyzed 117 cores samples from the Bakken formation. A statistical collation of all the sample gave the results shown in the table.

Table 8-Mechanical Properties of the Bakken

Member of the Bakken	Porosity (%)	Clay Content (%)	Static Moduli (Gpa)	Static Moduli (MMPsi)	Dynamic Modulic (Gpa)
Upper and Lower Bakken	5.052	44.523	65.065	9.437	59.065
Middle Bakken	4.959	7.583	60.279	8.743	57.137

Source: (He et al., 2019)

Isotropic Poisson's Ratio from Zamiran, Rafieepour, & Ostadhassan (2018) is also displayed below.

Table 9-Isotropic Poisson's Ratio of the Bakken

Bakken Members	Poisson's Ratio
Upper Bakken and Lower Bakken	0.26
Middle Bakken	0.24

Source:(Zamiran et al., 2018)

4.3 HAYNESVILLE FORMATION

The Elm Grove Plantation #15 was the first vertical well to be drilled into the shale gas found in the Haynesville-Bossier formation in April 2004. The first horizontal well was drilled in December 2007. After this well was drilled, numerous operators rushed into the Haynesville which caused an increase in the cost of lease greater than $25000 per acre and royalty ranging from 25 to 30% (Pope, Peters, Benton, & Palisch, 2009).

4.3.1 Geology and Geochemical Properties of the Haynesville Formation

The Haynesville formation is an organic-rich, upper Jurassic shale found in the areas of northeast Texas and northwest Louisiana with a surface area of about 5.8 million acres. On top of the Haynesville shale is Bossier and Cotton Valley Sandstone formation. Beneath the Haynesville formation is the Cotton Valley sandstone formation. The Haynesville formation is a laminated formation. Mineralogy of the Haynesville is always not the same throughout the formation. The stratigraphy of the Haynesville formation is displayed below.

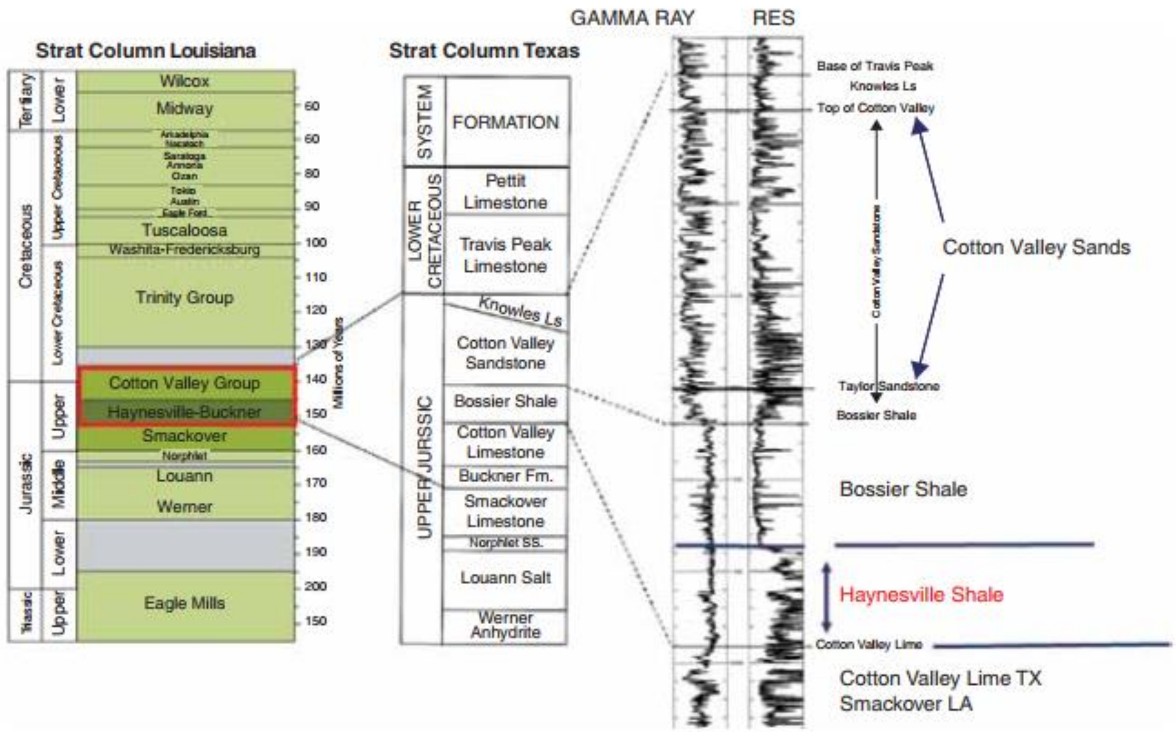


Figure 12- The Stratigraphy of Haynesville and its adjacent Formations

Source: (Thompson et al., 2009)

The formation is one of the largest and most active shale gas play among all shale gas plays in the United States. Haynesville-Bossier is a black organic shale composed mainly of clay, silt, and sand. The clayey content does not exceed 40 % and can be very low in calcite-rich sections of the formation. Haynesville is dry gas formation, thermally matured with a vitrinite reflectance (Ro) in the range of 1.3 to 2.4 (Pope et al., 2009). The Haynesville formation has unique characteristics in terms of temperature, vertical depth, and abnormal pressure gradient. It has a temperature range greater than 300 °F, vertical depth ranging from 11000 to 14500 ft. and an overpressure gradient of 0.72 to 0.9 psi/ft. Its permeability ranges from 100 to 500 nanodarcy (Thompson et al., 2009). Haynesville has a porosity of 6 to 12 %, and water saturation of 25 to 35 % (Pope et al., 2009).

The Haynesville runs from East Texas, through Northern Louisiana, Southern Arkansas, and into Alabama and Mississippi. The Haynesville extends into almost twenty (20) countries (Pope et al., 2009).

The highly productive zones of the Haynesville are found within the parishes of Bossier, Red River, and Desoto all in the Louisiana start and a Shelby in Texas is also noted for high initial production rate. Thompson et al. (2009) displayed a bubble graph showing the cumulative production for the best three months in the initial years of production in the Haynesville formation. The graph is shown below.

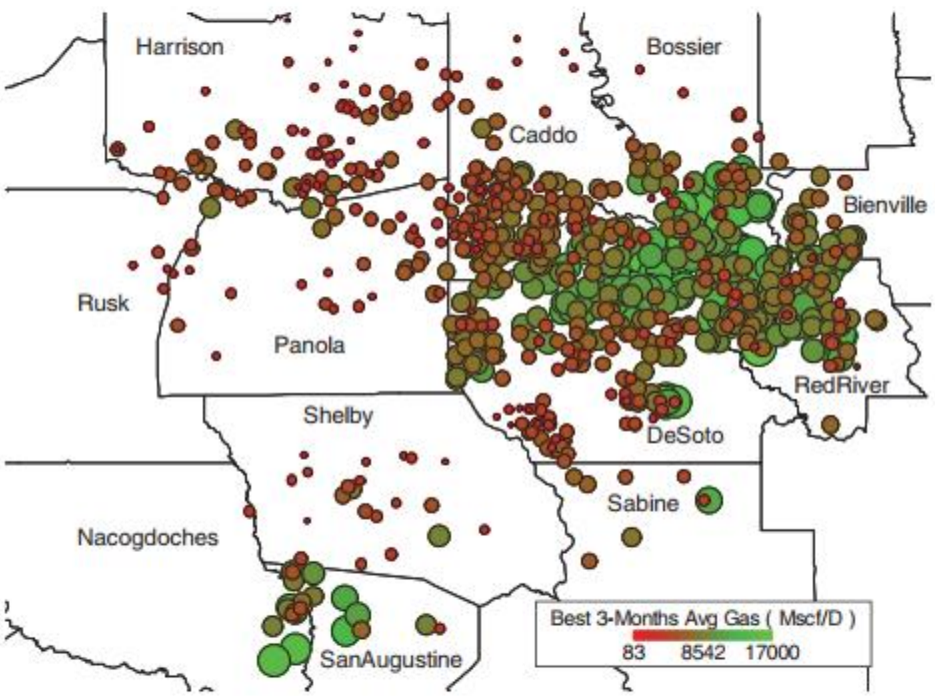


Figure 13-Average Gas Bubble Map for Haynesville Horizontal Wells

(Thompson et al., 2009)

It can be seen that majority of the production is from Caddo, Red River, Bossier, Bienville, and Desoto – these regions are regarded as the high-quality section of in the Haynesville formation (Thompson et al., 2009).

The Haynesville has a maximum thickness of 400 ft. along the Arkansas/Louisiana border, however, it was observed that the high-quality regions in the Haynesville are thinner with a thickness of 180 ft. These high-quality regions have three major characteristics that differentiate them from the rest - the thinness of the rock formation, low clay content and high free gas porosity. The gas found in this formation constitutes about 80% in the form of free gas and 20% in the form of adsorbed gas (Pope et al., 2009). The regions with the highest quality are noted for their lower clay content and higher calcite content while the area with low productive has higher clay content and lower calcite content. Low clay content allows the formation to be drilled and fractured easily as compared with the sections with high clay content. The calcite content in the Haynesville formation results of erosion of carbonate minerals from nearby shoals (Thompson et al., 2009).

The total organic content of the Haynesville ranges from 3 to 5%. The thickness, gas porosity and mineralogy have a major influence on the level of producibility in the Haynesville. The regions in Haynesville formation with low smectite content and high calcite content do not have major issues of swelling clays and proppant embedment due to the stiffness of the calcite found in the matrix of the rock formation. This cannot be said for areas with high clay mineral smectite in them (Thompson et al., 2009).

Due to the large formation pressure gradient, creating a large surface area by creating complex fractures through hydraulic fracturing means is essential in improving production. The Haynesville has a fracture gradient of 0.98 to 1.06 psi/ft (Pope et al., 2009).

The Haynesville has Young's modulus ranging from 1.0 Gpsi to 3.5 Gpsi. Because of the high pressure and softness of the Haynesville formation, there is a risk of proppant embedment, fine generation and proppant crushing which can reduce the permeability of the proppant pack and instability in the drilled wells (Thompson et al., 2009).

The regions with the highest reservoir quality also have good mechanical properties to some extent. However, some of the good quality shales depict some ductility due to higher clay content and lower calcite content (Thompson et al., 2009).

4.3.2 Mechanical Properties of the Haynesville Formation

The Haynesville formation is regarded by most scholars as a soft formation due to its low Young's Modulus ranging from 1 to 3 Gpsi and a Poisson's ratio of 0.23 (Pope et al., 2009; Thompson et al., 2009). There are certain sections of the Haynesville formation whose Young's Modulus does not fall within the said range due to anisotropy and the variation in the mineralogy of the Haynesville formation. Sone & Zoback (2013) confirm that the brittleness of shale-gas reservoir is dependent on the composition of the formation and its anisotropic nature.

The Haynesville formation is laminated, the calcite, clay and quartz content in the basin varies throughout the laminated shale. This causes some of the shale interval to be very brittle while a portion of the shale is also very ductile. The brittleness in the Haynesville formation is increased when the quartz content is higher and reduced when the clay content (illite and smectite) is higher. The carbonate (calcite and dolomite) content in the formation has a moderate effect on the brittleness of the Haynesville rock formation (Saneifar, Aranibar, & Heidari, 2014).

Saneifar et al. (2014) identified four different rock classification in a core sample analyzed from the Caddo country in Louisiana. The table below is an extract from Saneifar et al. (2014), showing the four classifications of rocks in the Haynesville formation. The Haynesville laminated shale has different mineral composition and kerogen content which affect the brittleness of the formation in its various sections.

Table 10-Properties of identified rock classes in the Haynesville shale-gas formation

Rock Class	Brittleness Index (%)	Quartz (vol%)	Illite (vol%)
RC4	47-80	0.30-0.56	0.15-0.30
RC3	50-70	0.18-0.49	0.15-0.30
RC2	30-50	0.19-0.45	0.20-0.34
RC1	20-55	0.19-0.45	0.20-0.35

Source:(Saneifar et al., 2014)

4.4 BARNETT FORMATION

The Barnett formation is one of the most successful shale plays in the United States (Bowker, 2007b). Exploration and production began in the Fort Worth Basin area located in north-central Texas way back in the 1900s. This basin is a mature petroleum system. In the early days in 1998, production from this basin was from conventional reservoirs located in the basin with a geologic age ranging from Ordovician to Permian. In recent days, an unconventional unassociated gas reserve has been discovered in this formation (Pollastro, Jarvie, Hill, & Adams, 2007).

The Newark East field which is the largest producing field in Texas produced a cumulative gas 1.8 Tcf of gas from January 1993 to January 2006. The Newark East field is rated as the second highest in the United State in terms of annual gas production. It is estimated that about 26 Tcf undiscovered technically recoverable gas is available in the Barnette shales in the Fort Worth Basin (Pollastro et al., 2007). About 99% of the total amount of production in the Barnett formation is from the Newark East field (Bowker, 2007a).

4.4.1 Geology and Geochemical Properties of the Barnett Formation

Hydrocarbon found in the Barnett has geological age ranging from Ordovician to Lower Permian. The prominent mineral in the Ordovician, Mississippian, and lower Pennsylvanian reservoirs are carbonate rocks while that of the middle Pennsylvanian to Lower Permian reservoirs are mostly clastics. Based on the thermal maturity of the Barnett shale rock, the majority of the gas accumulation is found in the northeastern part of the basin or along the Ouachita thrust front, where the rock is thicker and thermally mature. The oil accumulation is also found in the areas around the north and the west in the basin where the thermal maturity is lower. The areas with mixed oil and gas traces are those areas that serve as the transition zones in terms of thermal maturity (Pollastro et al., 2007).

The Fort Worth Basin is a shallow basin with a total surface area of 15000 mi^2 (38100 km^2) through north-central Texas. This basin was formed as a result of the late Paleozoic Ouachita orogeny which occurred due to a tectonic collision leading to the thrust fault formation. The Ouachita thrust serves as the eastern boundary of the Fort Worth Basin (Pollastro et al., 2007). The Fort Worth Basin is bounded by Muenster arch to the northeast, the Ouachita thrust system to the southeast, the pre-Mississippian Bend arch to the west and the Red River uplift to the north (Bowker, 2007b).

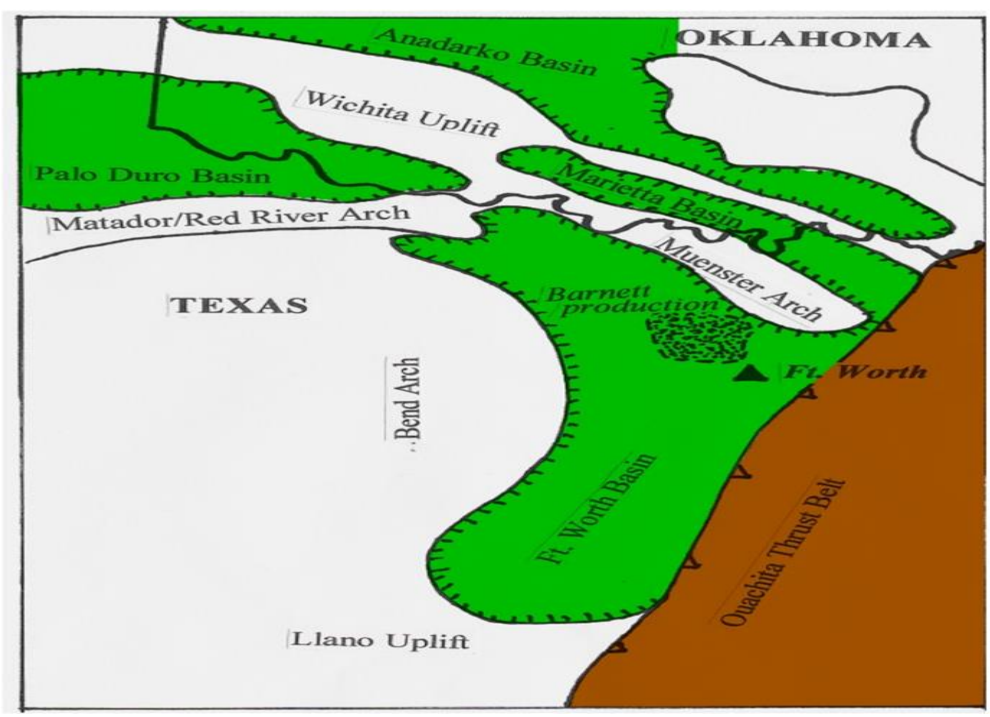


Figure 14-Regional structural setting around Newark East field

(Bowker, 2007b)

The Barnett is divided into informal members. The lower overlain the Ordovician Viola Limestone or Simpson Group. Part of the lower Barnett rest on the Ordovician Ellenburger Group. The upper and lower Barnett are separated by the Forestburg limestone with the Mississippian Marble Falls Limestone laying on top of the upper Barnett. The upper Barnett is about 1150 ft thick while the Forestburg limestone varies in thickness with a maximum thickness of 200ft in the Wise and Denton countries (Bowker, 2007b). The stratigraphy and the various formations in the Bend Arch-Fort Worth Basin are shown below.

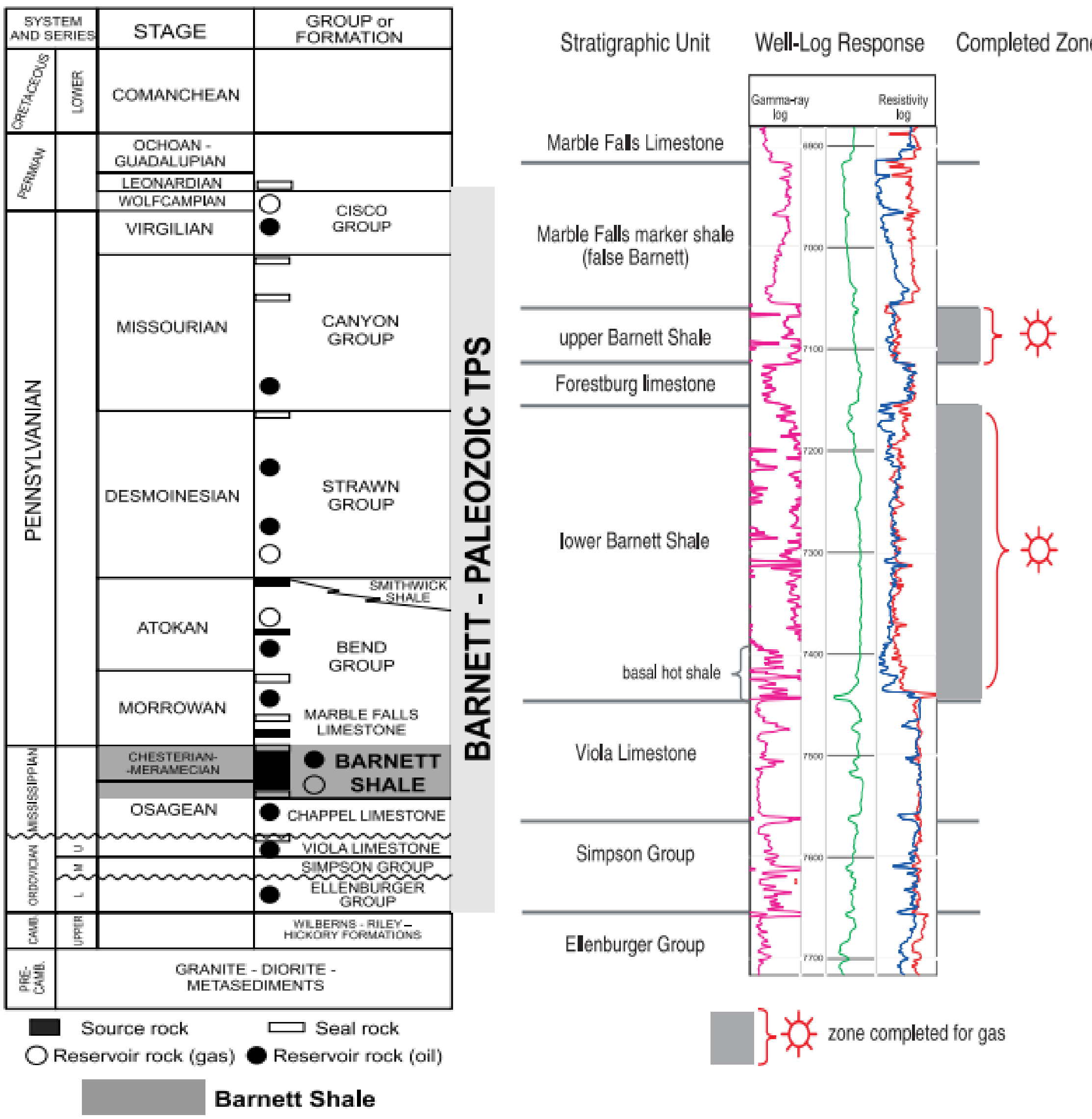


Figure 15-Generalized subsurface stratigraphic section of the Bend arch– Fort Worth Basin (Pollastro et al., 2007)

The Barnett black shale is made of about 45% quartz, 27% clay (mainly illite, with a trace of smectite), 8% calcite and dolomite, 7% feldspar, 5% organic matter, 5% pyrite, 3% siderite, and a trace of native copper and phosphatic minerals. The Barnett has an average porosity of 6 % and a low permeability measured in nanodarcy. The initial total organic content of the Barnett was about 20% when it was deposited. In the thermally mature areas in the formation, the total organic content is about 4.5 wt. %. The total organic content in the Barnett is directly related to the gas in place. Sections in the formation with high organic content have higher gas in place as compared with areas with low organic content. The Barnett is made up of Type 2 kerogen. Just a little portion of the total amount of hydrocarbon generated in the Barnett source rock is stored in the formation or its surrounding reservoirs. A chunk of the hydrocarbon generated escape to the surface. The top part of the Barnett ranges from 6600 to 8000 ft in depth. The radius of the average pore throat in the Barnett formation is less than 0.005 micrometer. The Barnett is estimated to have an average of 150 BCF/mile^2 of gas and has an average temperature of 180 °F. Gas in place is stored in the matrix porosity and can also be adsorbed unto organic matter (Bowker, 2007a, 2007b).

One unique characteristic of the Barnett that has contributed to its success is the emplacement of the Ouachita system. Researchers highlighted that the thermal history of the Barnett has a direct link with the Ouachita system. Areas in the Barnett at which the Ouachita is bonded to have the highest thermal maturity in the Basin. This is because of the generated heat caused by the emplacement of the Ouachita system which leads to the movement of heat to the part of the Barnett closer to the Ouachita system. The source of the heat is as a result of the movement of hot fluid from the Ouachita system through the rocks into the Ellenburger formation (Bowker, 2007b).

In the Barnett formation, areas with R_o between the interval of 0.6 and 1.1 % are mostly noted for the production of oil and that of the gas producing regions are noted for R_o greater than or equal to 1.1 % (Pollastro et al., 2007).

Though researchers do not agree on the specific characteristics of the Barnett that account for its high productivity, Bowker (2007b) claims that, the prolific nature of the Barnett is as a result of the overpressure and fully gas saturated state of the formation. Bowker (2007b) explained that though the reservoir has a pore pressure about 0.52 psi/ft in the gas-saturated portion of the play, the creation of fractures disrupts the equilibrium of the formation which leads to dissemination of gas from the matrix into the hydraulic fractures. Others authors attribute the prolific nature to the existence of natural fractures in the formation.

Bowker (2007a) explained that the production from the Barnett is relatively low at areas closer to geological features such as faults, synclines, and anticlines in the Fort Worth basin. It is interesting to note that, though there are numerous natural fractures in areas around the faults, synclines, and anticlines, production in these areas is poor. This explains why Bowker (2007a) affirms that the natural fractures in the Barnett do not account for the prolific nature of the formation. The author also explained that, though there are natural fractures found in the Barnett, these fractures are filled with carbonaceous materials predominately calcite. The author argued that if there are numerous open fractures in the Barnett formation as claimed, there would have been a rapid migration of free gas from the shales into the overlying rocks, since the shales in the Barnett formation acts as the source rock, reservoir rock and the seal, which will also result in a decrease in the pore pressure in the formation thereby the Barnett formation would not be slightly over pressured as seen in most areas today. The author continued that, the total gas in place would have been reduced due to the migration of the free gas and the attributed gas in place would have been the only total amount of adsorbed gas in the formation. Therefore the Barnett should be regarded as a shale that can be fractured containing a rich concentration of gas but not as a fractured shale.

CHAPTER 5

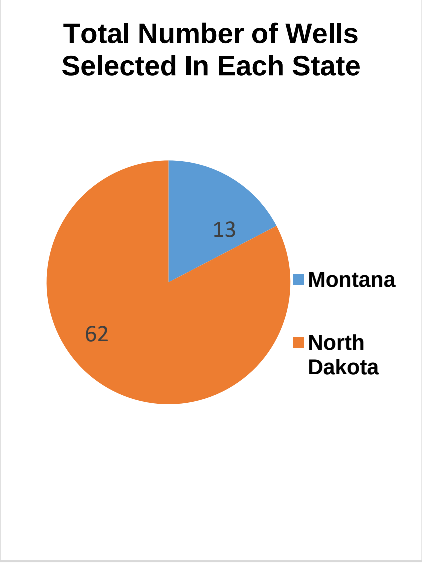
RESULTS AND DISCUSSIONS

This chapter discusses the results obtained from the classification of the data extracted from the database of *fracfocus* and the relationship between of the type of fracturing fluids selected for fracturing treatment and the reservoir characteristics of the various unconventional plays discussed in chapter 4. The geology, mineralogical and geochemical properties of the unconventional reservoirs would be used as a basis for the affirmation of the motive to which operators selected a particular type of proppant and fracturing fluid as against the other.

5.1 BAKKEN

5.1.1 Results

A total number of 75 well data were analyzed for the Bakken formation. The data selected were all hydraulic fractured well in 2015. The graphs below show the distribution of the data collected in each state and country. 62 of the selected wells were from North Dakota and the remaining 13 from Montana.



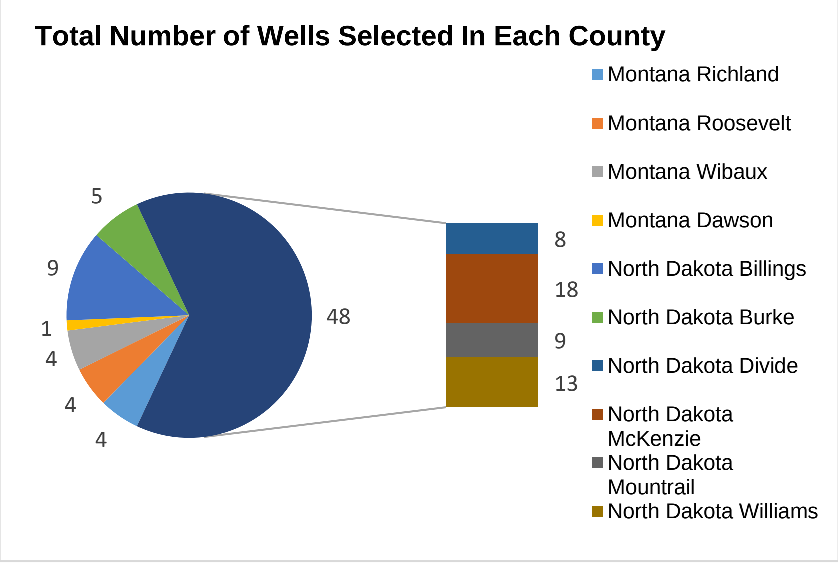


Figure 16-Hydraulic Fractured Wells Selected in the Bakken Formation

5.1.1.1 Proppant Used

After analyzing the data, it shows that 66.7 % of the wells were propped with sand only, 16 % was a combination of sand and resin-coated sand, 6.7% of the wells had no indication of the proppants used, 1.3% was a combination of sand, ceramics, and resin-coated sand, and 9.3 % reported as sand and ceramics.

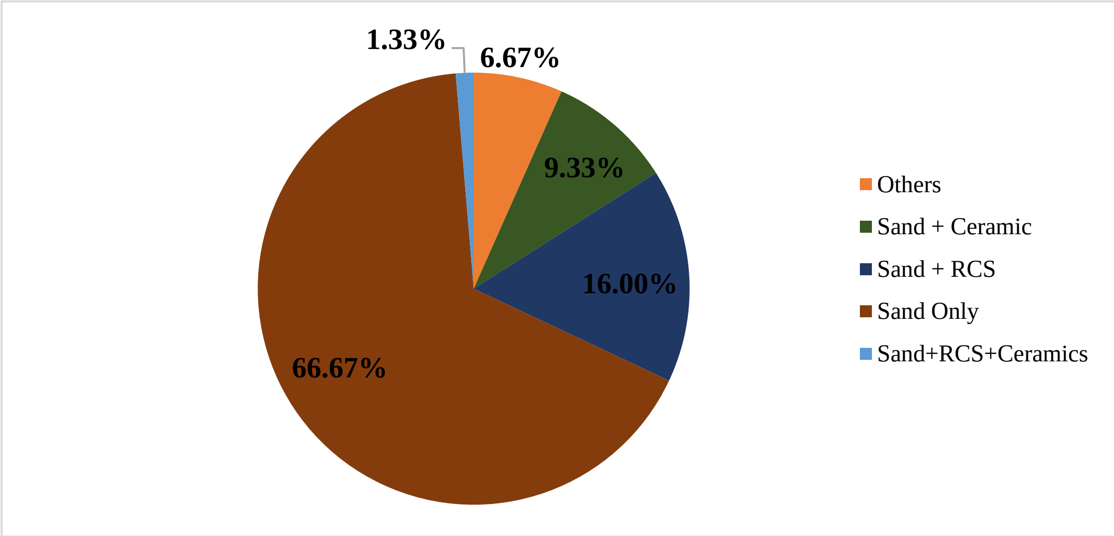


Figure 17- Proppant Used in the Bakken Formation

The various states in the Bakken to which the various combination of proppants was used are also displayed in the graph below.

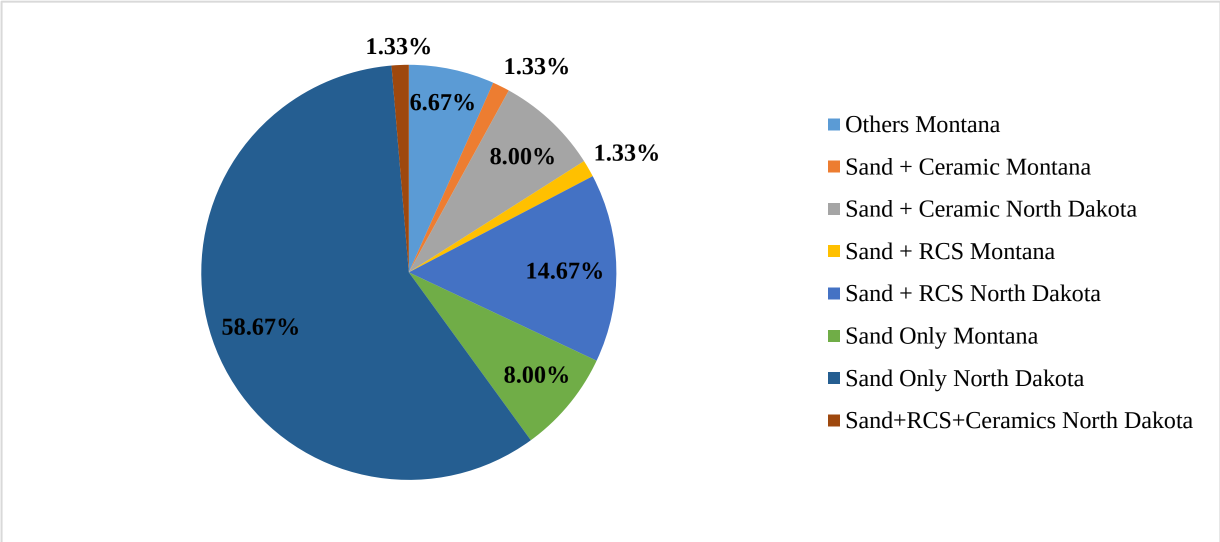


Figure 18-Proppant Used in the various States in the Bakken

5.1.1.2 Fracturing fluid Used

Among the 75 wells analyzed, 68 % reported as well fractured with the hybrid type of water-based fluid, 8 % as linear, 17.3% as slick water and 6 % as those fractured using other secondary frac fluids. Graphs of the various distribution of fracturing fluids and the type of proppants they carried with the specific states in which the wells were drilled are all shown below.

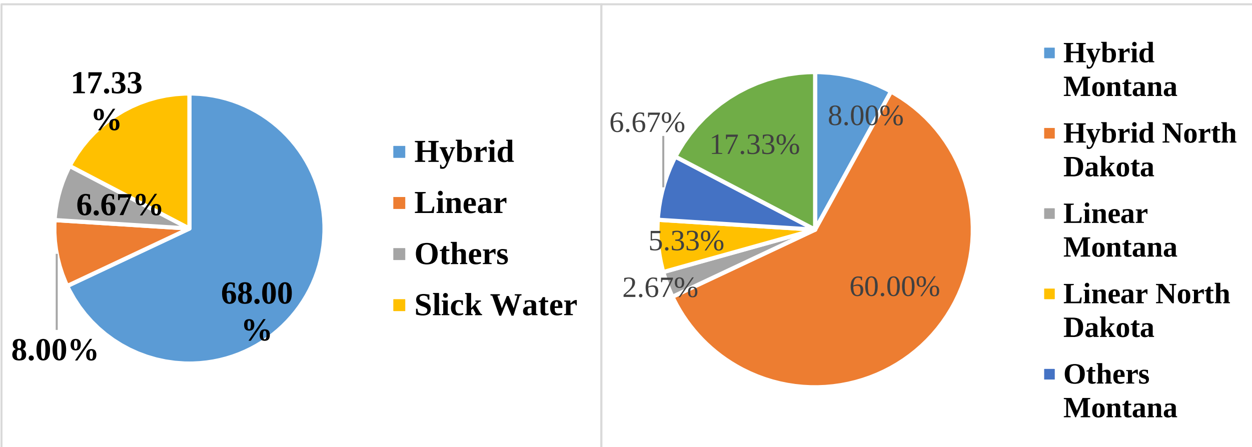


Figure 19- Hydraulic Fracturing Fluid used in the Bakken Formation

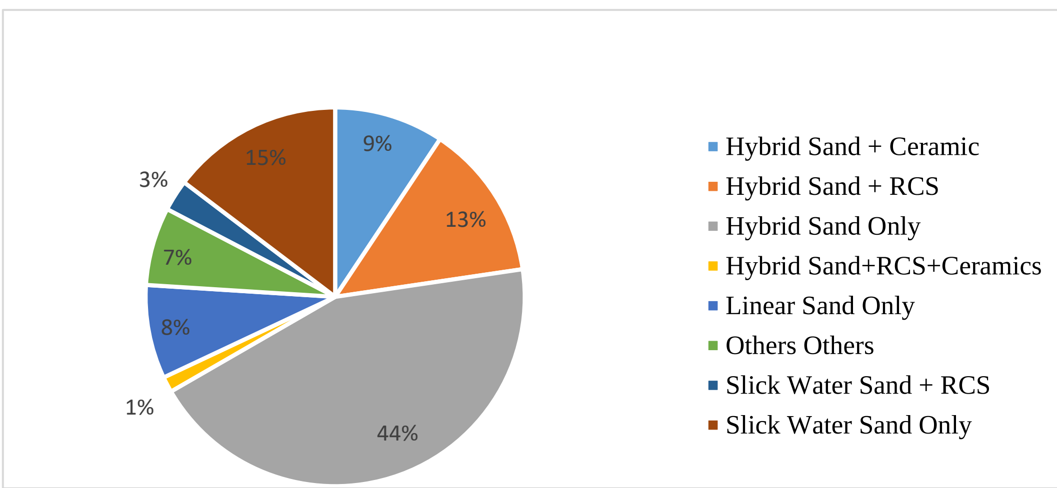


Figure 20- Carrier Fluids and the Proppants Type Used in the Bakken

5.1.2 Discussions

5.1.2.1 Proppant Used

In the selection of proppants for any frack job, the three major consideration is the closure stress of that formation on the proppant, the availability of a type of proppant and finally the cost of the proppant. From the graphs displayed, it can be seen that all the various types of proppants were utilized in the Bakken formation. It is not surprising that uncoated sand reported as the highest - since it is the widely used proppant.

Bakken has closure stress ranging from 5500 psi to 9500 psi depending on depth and location ("Hexion Fracline," n.d.; Terracina et al., 2011). Within this range of closure stress, it is possible to consider all the three major type of proppants depending on the stress value in the location of the well. As indicated in figure 6 and Table 1, sand can handle closure stress less than 6000 psi, resin coated sand can handle closure stress up to 8000 psi and that of the intermediate strength ceramics can handle closure stress up to 10000 psi. With this variation in the strength of proppants and the closure stress in the Bakken formation, the specific location and closure stress of that location of the well in the Bakken formation will be prominent in its selection.

Estimation of the closure stress can be done by approximating the minimum horizontal stress as being equal to the closure stress of the formation. The formula for this calculation is shown in the previous chapter. In calculating the minimum horizontal stress the Biot's coefficient for the Bakken is mostly assumed to be 1 by most researchers. Also, the tectonic stress is also assumed to be zero for the Bakken since it is considered as an incratonic formation and highly stable.

In the selection of proppants, it should be noted the maximum closure stress from the estimation should be used. This is because closure stress is not static and keep changing throughout the life of the formation. Therefore when selecting silica sand for a formation such as Bakken, care should be taken as it has a high tendency to crush into fines when the closure stress of the formation is above the strength of proppant. This can be a serious issue since 5 % of fines produced can reduce the total conductivity of the proppant pack by 54 %(Terracina et al., 2011).

A study reported by Liang et al. (2016) where different proppant types in different sizes used in the Bakken exhibited that, the use of 100 % ceramics proppant gave the highest cumulative production within 270 days while that of 100 % silica sand reported as the lowest. The issue is, will 100 % ceramics proppant usage be economical for the fracturing job. The use of ceramics may have a higher initial cost, however, the productivity of the well cannot be compared to that of the uncoated sand due to the high conductivity of the proppant, as a result, the cost can be higher but the productivity of the well will compensate for it. However, there should be a compromise between the conductivity of the proppant used and the economics of the project. Thereby, operators choose to use the hybrid form of proppant selection by the use of both silica sand and low-density ceramics to capture the issues of both conductivity and economics.

Another issue concerning the Bakken formation is the issue of proppant embedment (Akrad et al., 2011; Terracina et al., 2011). This embedment occurs in areas with high clay content (Liang et al., 2016). The lower Bakken has a significant amount of clay(Akrad et al., 2011). In such a case the use of a high strength proppant such as the ceramics will not mitigate the effect of the reduction in conductivity caused by embeddment. The use of the resin coated sand which has the ability to bond to each other and redistribute the stress on the proppant is the best. Also, the resin coated sand is capable to encapsulate the fine produced to prevent the reduction in fracture width and conductivity.

5.1.2.2 Fracturing Fluid Used

One parameter that is very useful in selecting the right fracturing fluid is the brittleness index. This parameter can either be a function of the mineralogy of the formation or a function of Young’s modulus and Poisson’ ratio which was developed by Rickman et al. (2008). Using the Young’s

Modulus extracted from He et al. (2019) and Poisson ratio from Zamiran et al. (2018) to calculate the brittleness index, the results below were obtained.

Table 11- Brittleness Index for Bakken Formation

Member of the Bakken	**Static Moduli (Gpa)**	**Static Moduli (GPsi)**	**Poisson Ratio**	**Brittleness Index (%)**
Upper	65.065	9.436880423	0.26	88.26343159
Middle	60.279	8.742729809	0.24	87.30521292
Lower Bakken	65.065	9.436880423	0.26	88.26343159

The results above show the brittleness of the Bakken formation. This corresponds with a statement from Hamlin et al. (2018) which confirms how brittle the Bakken shale is. The shows how suitable the Bakken is to hydraulic fracturing. To fracture such a brittle formation, the use of the hybrid fracturing fluid or slickwater is most recommended.

This corresponds with the results shown from the wells collected for analysis where 68% of the wells selected used the hybrid type and 17% of the wells used slickwater. This is because, in brittle formation, slick water or hybrid is able to create a complex fracture system as compared to a viscous crosslinked fluid that creates a bi-wing fracture system. The slickwater fluid is able to penetrate deeper into the fractures into micro and nano-fractures thereby increasing the complexity fractures and lateral length created in the formation (Barati & Liang, 2014). Also, the use of the slickwater helps in increasing the surface area of the created fracture and help to reduce issues of formation damage caused by gel residue in the formation. However, using slickwater requires a lot amount of water to be pumped into the formation. This is because there is no formation of a filter cake that would help control leak off of the fluid as compared to that of viscous fluid type. Also, the slickwater has very low proppant carrying ability and carrying of conventional ceramics proppants tend to be a problem. The proppant tend to settle and issues of screen out are rampant. In the data analyzed from the Bakken formation, it can be seen that no ceramic proppant reported in any well fractured with slickwater through the 75 well data collected.

Taking into consideration the closure pressure of the Bakken formation and how the use of ceramics proppant can withstand the high closure stress however, there is difficulty in the transportation of proppants of higher density using slickwater. Therefore, the use of the hybrid fluid type was necessary. The hybrid type can either be a combination of the slickwater and a crosslinked fluid or a combination of linear and a crosslinked fluid. In using the hybrid, a pumping schedule ought to be designed where the less viscous fluid which can be the linear or slickwater fracturing fluid is pumped for the creation of complex fracture network while the viscous crosslinked fluid is used as a tail in to flush and carry proppants near the wellbore into the fractures to prevent screenout.

It is crucial to note that, fracture propagates predominately in the transverse direction for most of the cores studied in the Bakken (Jabbari, 2013). This demand that the fluid used for fracturing should help improve the fracture width, should be cleaner with less gel residue and can transport better proppants efficiently. This is exactly what the hybrid fluid type is solving in the Bakken formation. In areas such as the Western North Dakota, where proppant flow back very easily, tail in of viscous crosslinked fluids can be used to flush the proppant from the wellbore into the fractures after the less viscous fluid is used.

5.2 HAYNESVILLE

5.2.1 Results

5.2.1.1 Data Selection

The number of wells selected for analysis in the Hayneville formation is shown below. A total number of 75 wells were selected from the Louisiana State. Data from these wells were collected from Bossier, Caddo De Soto, and Red River. This is because statistics have shown these section of the Haynesville have high reservoir characteristics and produces that highest amount of gas in the Haynesville basin. This accounted for the selection of wells from these countries. All the selected data are fractured wells in the year 2015 as recorded in the database of fracfocus.

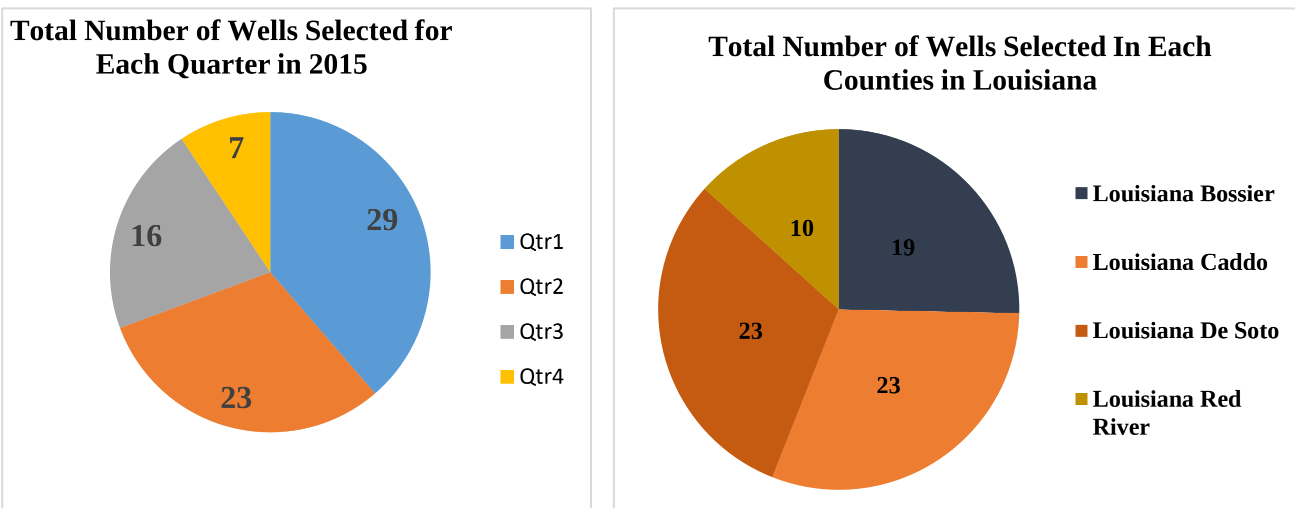


Figure 21-Number of Wells Selected in the Haynesville Formation.

5.2.1.2 **Proppant Used**

From the data analyzed, it was observed that the majority of the wells considered in the Haynesville formation used uncoated sand as their propping agent. 85 % of the wells used uncoated sand only for its fracturing treatment. 13 % of the wells were propped with both sand and resin-coated sand and about 1 % that had no record of the type of proppant used. A graph of the representation of proppants used in the selected formation is shown below.

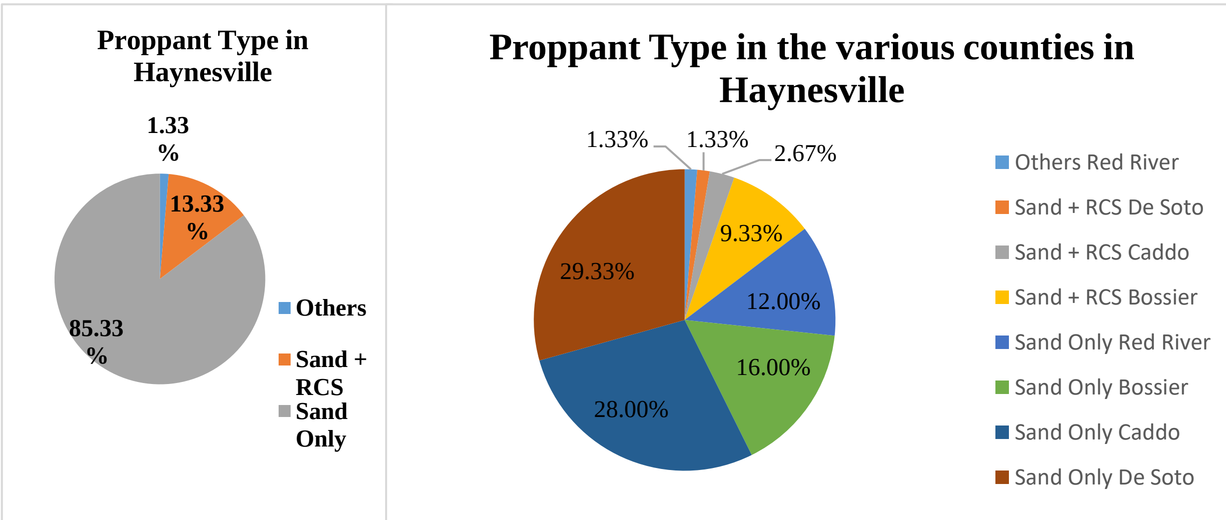


Figure 22-Proppants Used in the Haynesville Formation

5.2.1.3 Fracturing Fluid Used

From the data analyzed, it is shown that the three main fracturing fluids used in the Haynesville formation are hybrid water-based fluid, linear water-based fluid, and slickwater fluids. 79 % of the 75 wells selected used the hybrid type, 20 % of the wells are fractured using the linear type and 1 % used the linear type of frac fluid. The results of the fracturing fluids analyzed is shown below.

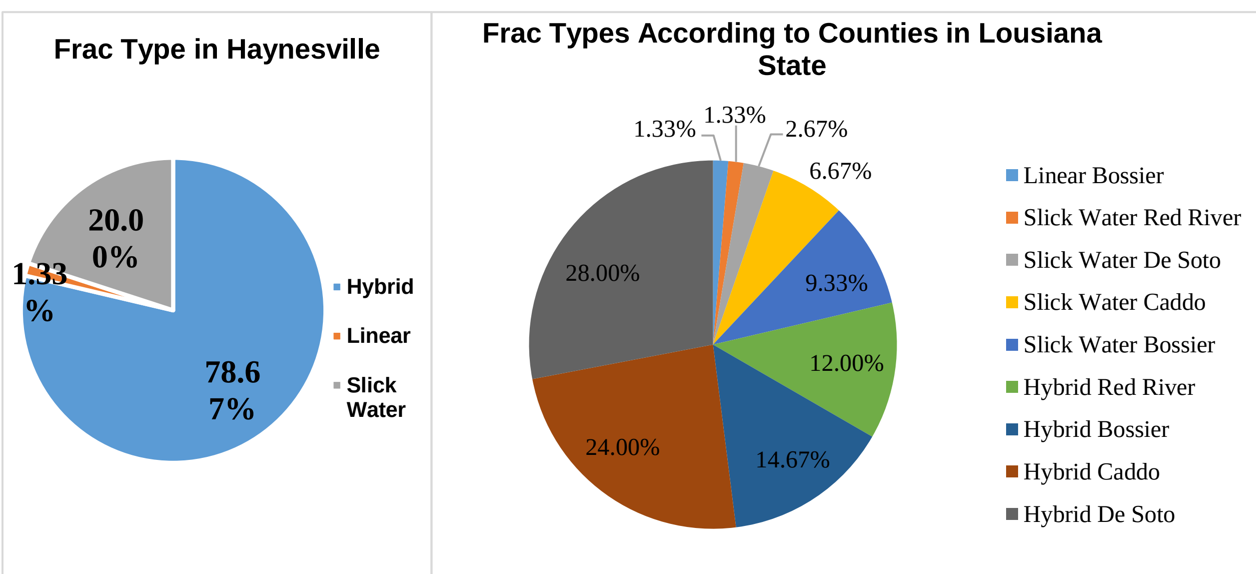


Figure 23- Fracturing Fluids Used in the Haynesville Formation

The carrier fluids and the proppants they carried are shown in the figure below.

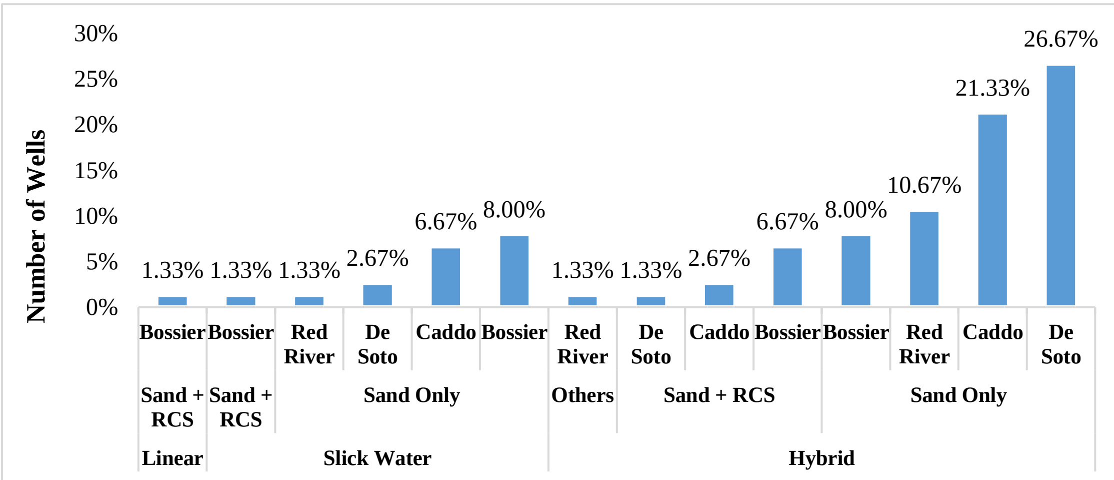


Figure 24-Fracturing Fluids and Proppant according to Counties in the Haynesville Formation

5.2.2 Discussions

5.2.3 Proppant Used

Statistics show that the widely used proppant is uncoated sand due to its affordability and availability, however, its overwhelming usage in the Haynesville formation is quite surprising. This is because, the Haynesville formation is an overpressured zone with pressure gradient that can be as high as 0.9 psi/ft., the closure pressure which is ultimate characteristics used in the selection of proppant ranges from 9000 to 12000 psi (Terracina et al., 2011). Within this range, uncoated sand has the tendency to crush under such high stress.

Also, the Haynesville formation is regarded as a soft formation, therefore, there is a high probability of the proppant embedment. As noted in the previous chapter, the Haynesville shale has some portion of its laminated shale that has a high clay content. This causes the shales to be less brittle and make the generation of fine very frequent to occur. In such a cause, the resin coated sand that has the ability to encapsulate the sand produced helps prevent the reduction of permeability of the proppant pack or the ceramics proppant that can withstand high closure stress should rather be considered. This explains 13 % of the proppant agents that reported as sand and resin coated sand. Terracina et al. (2011) confirm that the use of resin-coated sand in Haynesville formation is able to reduce the number of fines produced as compared to that of lightweight ceramic sand. Therefore for the section of the Haynesville that is ductile and noted for proppant embedment, the use of the resin coated sand should be considered.

Due to the high temperature of the Haynesville formation, the resin used in coating the sand should be able to withstand the high temperature of the formation without deteriorating.

One major consideration operators consider in the selection of proppant is cost. The ceramic proppant has the highest cost among all the propping agent. Therefore, most operators will logically have a second thought in its usage, however, the cost of the proppant should not be prioritized against the conductivity and productivity of the proppants. There should be a balance in cost and the conductivity during proppant selection.

The availability of proppant is also considered by operators when selecting the right proppant. If a proppant type which is suitable for use is not readily available, there will be a compromise to use the available form of proppant.

5.2.4 Fracturing Fluid Used

The major difference between the different fracturing fluids is their viscosity. The least viscous of the fluids is the slickwater. The viscosity of the fracturing fluid determines the lateral length of the fracture. As the viscosity of the fluid increases, the fracture width increases and the lateral length shortens (Phatak et al., 2013). Therefore, to gain a longer lateral length a less viscous fluid is to be used. The lateral length mostly drilled in Haynesville formation within 4000 ft. to 5000 ft. (Terracina et al., 2011; Thompson et al., 2009). Therefore a less viscous fluid that can penetrate deeper and create a longer length is required.

Because of the high changing pressure gradient in the Haynesville formation, one mechanism that enhances productivity in the formation is by increasing the surface area through complex fractures. Slickwater and the hybrid fluids also help in the creation of these complex fractures to increase the surface area. Therefore, the expectant fluid type that was anticipated to have a higher percentage was slickwater.

It is important to note that, because of the high closure, ceramics proppant type that can withstand high stress is expected to be used. However, slickwater which creates the complex fractures in such formations cannot carry high-density proppants such as the intermediate density ceramics proppant, therefore one will recommend the used of crosslinked fluids which are noted for its high viscosity.

Also, the high temperature in the Haynesville requires a fluid that can withstand such a harsh condition. The high viscous crosslinked fluid which can retain its characteristics without shear would have been most appropriate in this regard, however, one should not forget the high well damage caused by crosslinked fluids. A study from Prakash et al. (2014) showed that the use of crosslinked fluid in the fracturing process in the Haynesville showed evidence of gel residual which resulted in formation damage. Therefore the crosslinked fluid is not recommended.

One might ask, what accounted for the high percentage of the hybrid frac type that resulted in the analyzed data. The hybrid frac type is a combination of slick water and gelling agent or slickwater with a gelling agent and a crosslinker. This suggests that slickwater fracturing fluids were actually used in creating fractures, the gelling and crosslinking fluids used in conjunction with them can serve as tail fluids to increase the fracture width and also serve as flush fluids to aid in the efficient sweeping of proppant into the fractures due to their high viscosity. This helps in creating the complex fracture needed and carrying of better proppants with the viscous gelled fluid without increasing the well damage that would have occurred if the crosslinked fluid was used alone.

5.3 Barnett

5.3.1 Results

50 wells were selected to analyze the trend in the type of proppant and fracturing fluids used for fracturing activities in Barnett. The countries to which this data were chosen from are shown in the graphs below.

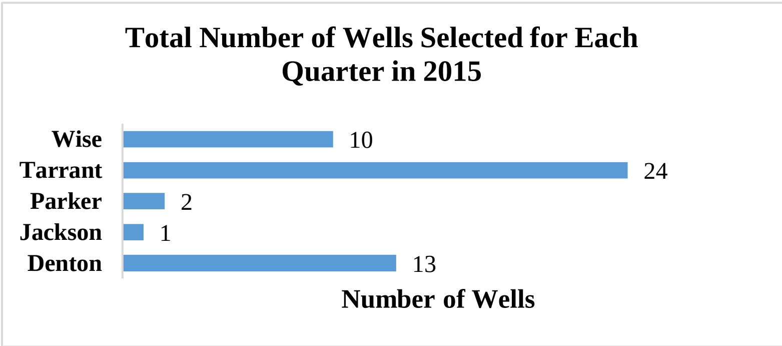


Figure 25-Wells Selected in the Barnett Formation

5.3.1.1 Fracturing Fluid Used

It was observed that 92 % of the selected well was fractured using slickwater while the rest of the 8% responded as linear and hybrid fracturing fluids. The graph of the fracturing fluid used in the selected wells is shown below.

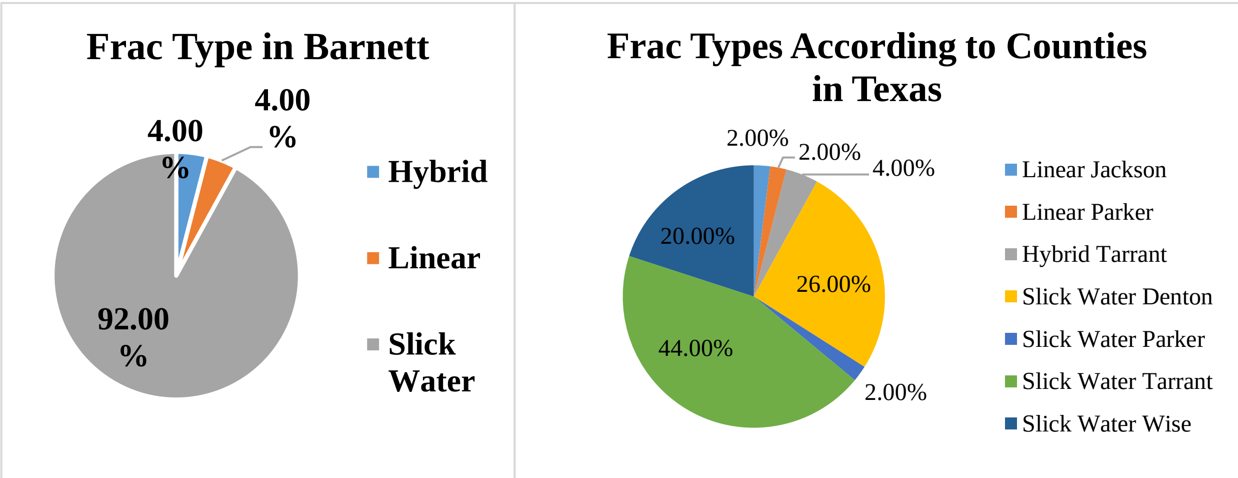


Figure 26-Fracturing Fluid Used in the Barnett Formation

The graph below shows the fracturing fluids and the proppant they carried for the selected wells in the various countries.

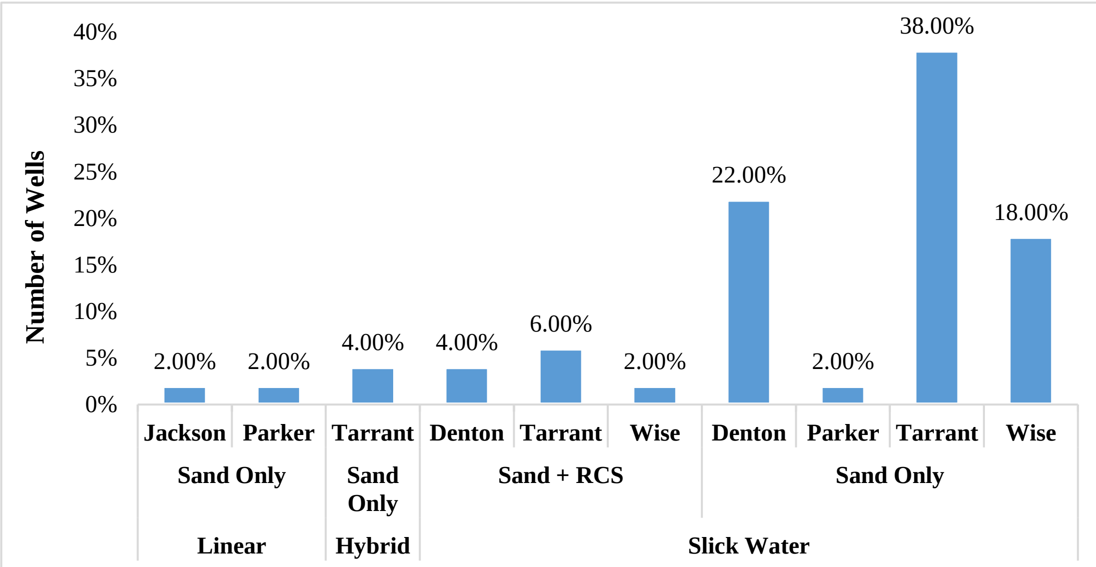


Figure 27-Fracturing Fluid and Proppants in the various Counties in the Barnett Formation

5.3.1.2 Proppant Used

After the analysis, it was observed that 88 % of the proppant used in the Barnett was uncoated silica sand while 12.5 % of the wells reported as wells propped with a combination of sand and resin-coated sand. The graph of this distribution is shown below.

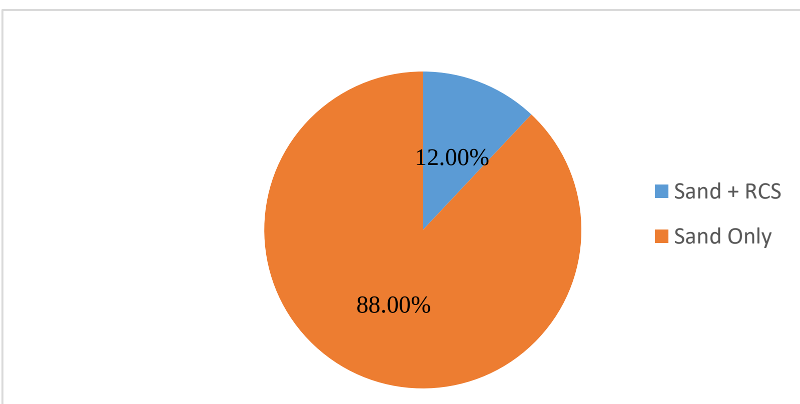


Figure 28-Proppant Type Used in the Barnett

5.3.2 Discussions

5.3.2.1 Fracturing Fluid Used

Majority of the fluids reporting as slickwater is in accordance with a lot of analysis done in the Barnett formation (Coulter, Energy, Benton, Thomson, & Oil, 2004; Palisch, Vincent, & Handren, 2010; Walker, Ray, Hunter, Brake, Fagin, & Steinsberger, 2007). This is because the natural fractures in the Barnett formation are so complex and when fractured with hydraulic fluid, the induced fracture becomes more complex and complicated forming more like a fairway as compared to the simple planar fracture in other formations (Coulter et al., 2004). The existing complex fracture becomes more complicated when a slickwater is used as compared to crosslinked fluids. This is because the low viscosity fluid is able to create a complex fracture system by penetrating deeper into the formation. This complexity is desirable in tight reservoirs such as the Barnett which helps in boosting production.

Also, the majority of operators use the slickwater in the Barnett formation because it aids in creating a longer lateral length and save cost on additives. Also, the low viscous slickwater system helps in reducing the height growth in the created fractures so as to prevent the penetration of the fractures into the underlying water in the Ellenberger formation. Formation damage is also at a minimum thereby aiding the flow of hydrocarbon.

The slickwater system has limited ability to carrying proppant. Due to this, the Barnett formation uses about 500,000 to 1000000 Ibm of proppants to sustain the fracture width of the created fractures which results in enormous barrels of water to create these complex fractures. The low viscosity of the slickwater makes settling of proppants very severe, this results in the usage of proppant with low density and smaller sizes.

5.3.2.2 Proppant Used

Increasing the conductivity in tight gas formation can boost the amount of gas drastically, however, in these tight shales where the permeability is in nanodarcy such as the Barnett formation, increasing the conductivity of the fractures to aid in production is not really the main motive. This is because the minimum conductivity attained is capable of producing an adequate amount of hydrocarbon from the formation. Therefore, any proppant that can open the pathway fairly for production is good enough for operators. This makes it not surprising why a majority of the propping agent is uncoated sand.

Also, the closure stress for the Barnett formation is in the range of 32 to 42 MPa. This range is good enough for the selection of proppant such as uncoated sand and resin coated sand when compared to the stress threshold for this proppant that was reported by Economides & Nolte (2000). Not forgetting that the most used fracturing fluid in the Barnett formation is slickwater, this requires that proppant which is buoyant and light in the frac fluid to prevent settling has to be chosen.

5.4 Trends in the Type of Fracturing Fluids and Proppants Used in the United States

A summary of all the data collected for all the five formations – Barnett, Haynesville, Bakken, Marcellus, and Eagle Ford, showing the predominant fracturing fluids, proppants and chemicals used in these formations are displayed in the figures below.

5.4.1 Fracturing Fluid

It was observed that the majority of the fractured wells were fractured using the hybrid fluid type which accounted for about 56% of the total number of wells selected. 36.50% of the total were fractured using the hybrid type that is made of a combination of slickwater and a crosslinker. 19.50% of the total are wells fractured with a hybrid fluid made up of a combination of linear gel and a slickwater. 36 % of the total also reported as wells fracked with slickwater, 5.5% with linear gel and 2.5 % reported as wells fractured with secondary fracturing fluids.

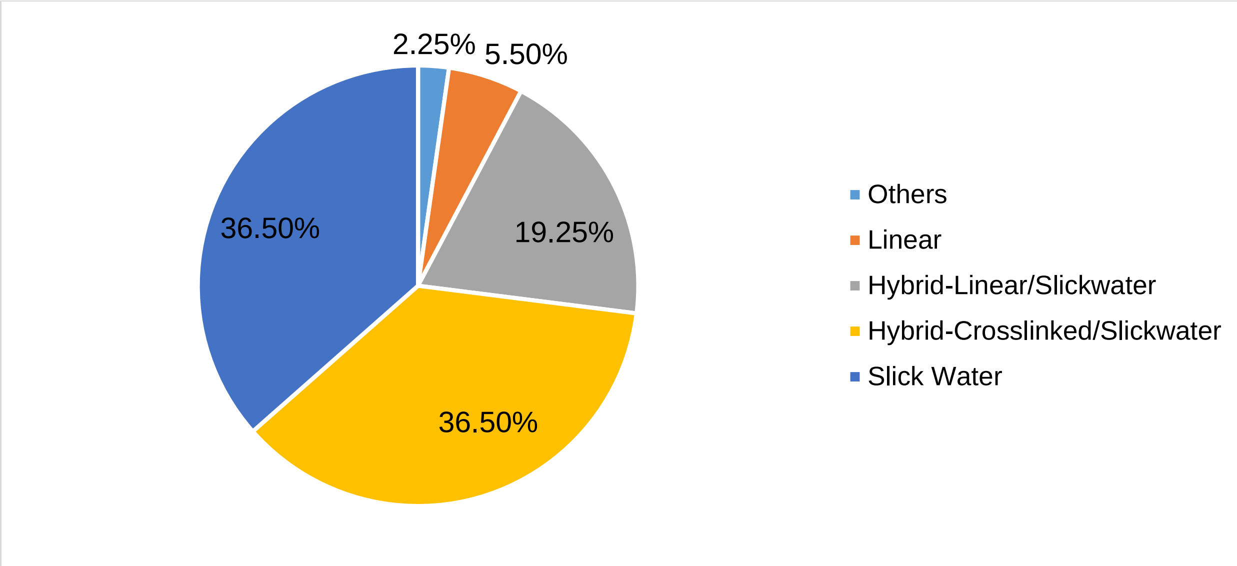


Figure 29-The Major Frac Fluids used in the Barnett, Haynesville, Bakken, Marcellus and Eagle Ford formations.

A summary of the number of wells in the various formations and the fracturing fluids used for the fracturing treatment is shown in the table below.

Table 12- Various Formations and their Respective Frac Fluids

Unconventional Formations and their Frac Fluids	Number of Wells	Number of Wells (%)
Barnett	**50**	**12.50%**
Linear	2	0.50%
Hybrid-Crosslinked/Slickwater	2	0.50%
Slick Water	46	11.50%
Haynesville	**75**	**18.75%**
Linear	1	0.25%
Slick Water	15	3.75%
Hybrid-Linear/Slickwater	25	6.25%

Hybrid-Crosslinked/Slickwater	34	8.50%
Bakken	**75**	**18.75%**
Hybrid-Linear/Slickwater	4	1.00%
Others	5	1.25%
Linear	6	1.50%
Slick Water	13	3.25%
Hybrid-Crosslinked/Slickwater	47	11.75%
Eagle Ford	**100**	**25.00%**
Others	4	1.00%
Linear	11	2.75%
Hybrid-Linear/Slickwater	12	3.00%
Slick Water	21	5.25%
Hybrid-Crosslinked/Slickwater	52	13.00%
Marcellus	**100**	**25.00%**
Linear	2	0.50%
Hybrid-Crosslinked/Slickwater	11	2.75%
Hybrid-Linear/Slickwater	36	9.00%
Slick Water	51	12.75%
Grand Total	**400**	**100.00%**

From the results shown in the table and the graph, it is shown that most of the operators are gearing towards the hybrid fluid type where a slickwater is used for the fracturing processing and a more viscous fluid (linear or crosslinked) is used to aid in the carrying of proppants. A number of wells also used solely slickwater. None of the data analyzed wells reported under the crosslinked frac fluids in the classification used for this project.

5.4.2 Proppant Used

Majority of the proppant used in the five major played studied is mainly sand. A graph of the distribution of the proppants used in the selected wells is shown below.

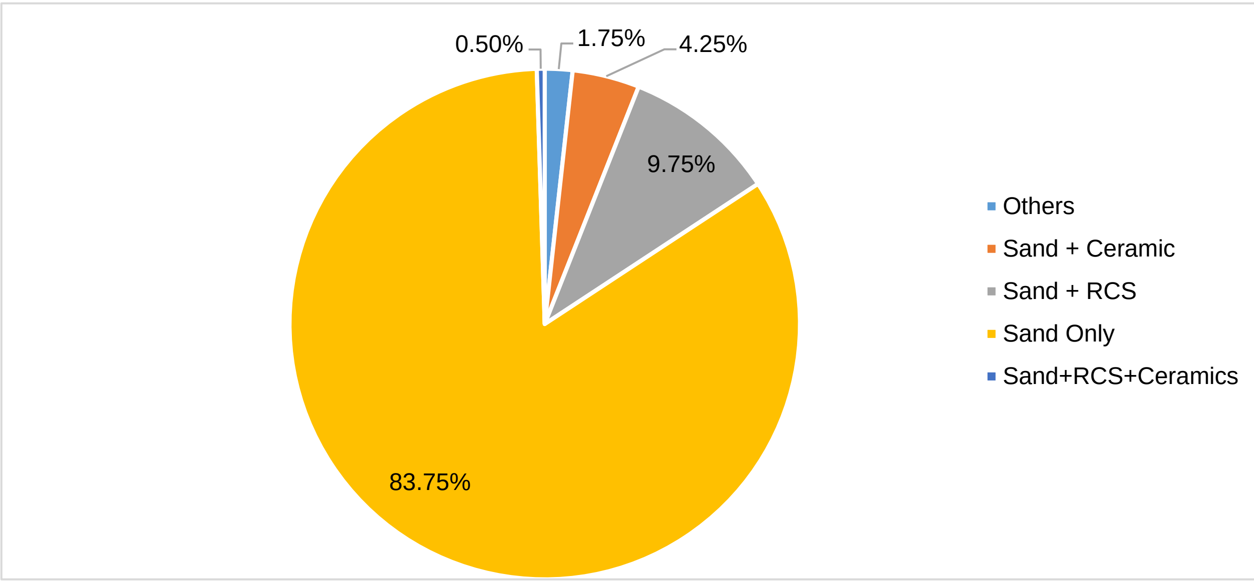


Figure 30-Proppants Used in the Selected Wells in the Barnett, Haynesville, Bakken, Marcellus and Eagle Ford formations

The table below summarizes the proppants used according to the various formations to which they are found.

Table 13-Proppant Used in the Various Formations

Selected Wells in the Various Unconventional Formation and the Proppants Used	Number of Wells	Number of Wells (%)
Bakken	**75**	**18.75%**
Others	5	1.25%
Sand + Ceramic	7	1.75%

Sand + RCS	12	3.00%
Sand Only	50	12.50%
Sand+RCS+Ceramics	1	0.25%
Barnett	**50**	**12.50%**
Sand + RCS	6	1.50%
Sand Only	44	11.00%
Eagle Ford	**100**	**25.00%**
Others	1	0.25%
Sand + Ceramic	8	2.00%
Sand + RCS	10	2.50%
Sand Only	80	20.00%
Sand+RCS+Ceramics	1	0.25%
Haynesville	**75**	**18.75%**
Others	1	0.25%
Sand + RCS	10	2.50%
Sand Only	64	16.00%
Marcellus	**100**	**25.00%**
Sand + Ceramic	2	0.50%
Sand + RCS	1	0.25%
Sand Only	97	24.25%
Grand Total	**400**	**100.00%**

It can be seen that the majority of the wells used sand only as their propping agents however, some of the wells also used a combination of sand and resin-coated sand or sand and ceramics. Just a handful of the wells used a combination of uncoated sand, resin coated sand and ceramics.

5.5 GUIDELINE

Based on the trend of fracturing fluids used from the data analyzed for the various formations, the selection of fracturing fluid can be simplified in the diagram shown below.

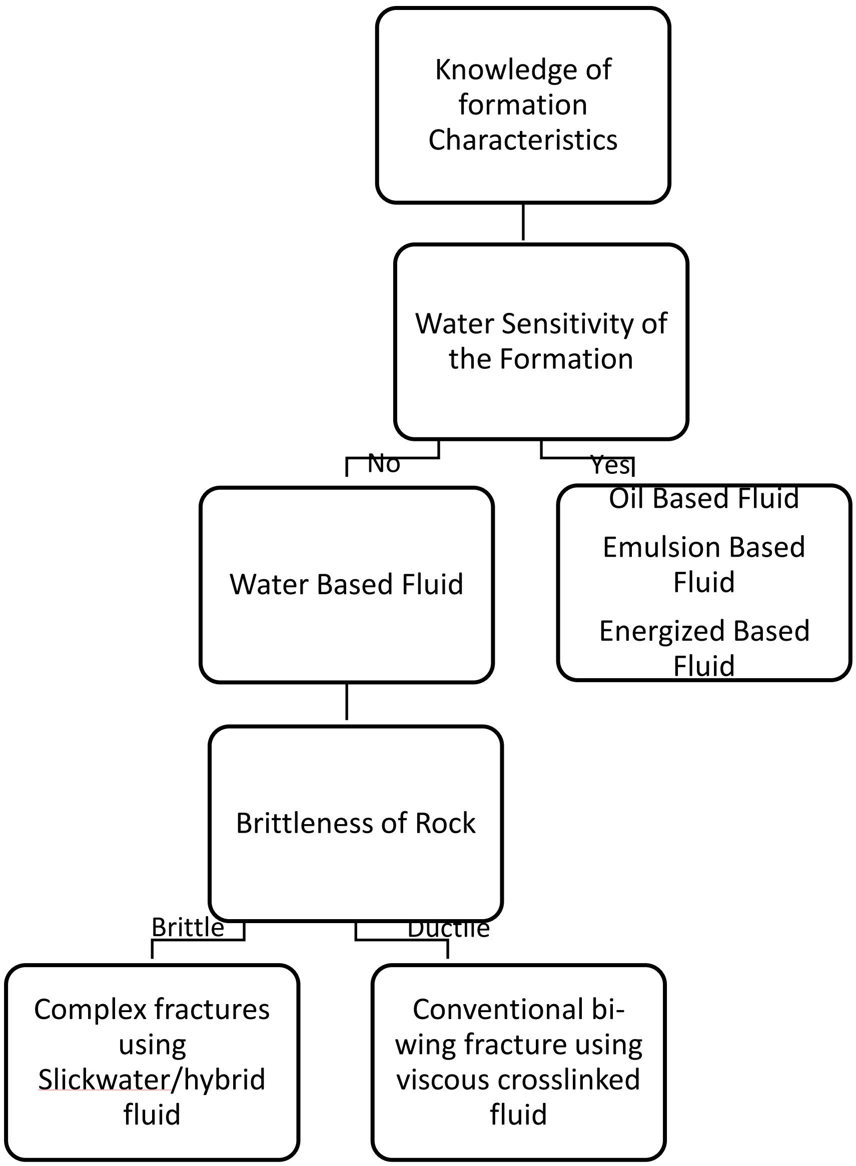


Figure 31-Guideline for the Selection of Fracturing Fluid

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 CONCLUSIONS

- Uncoated sand continues to serve as the major propping agent used in most of the wells that were analyzed due to its availability and affordability.
- Operators tend to pay less attention to conductivity especially in tight gas reservoirs such as Haynesville and Barnett where the permeability ranges in the nanodarcy which lead to the selection of uncoated sand despite the high closure stress of those formations.
- Most operators are gearing toward the hybrid and slickwater fracturing fluids as compared to the conventional viscous crosslinked fracturing fluid.
- None of the wells analyzed reported under the classification that uses solely crosslinked frac fluids for the wells analyzed in this project.

6.2 RECOMMENDATIONS

- The number of wells and formations can be increased so as to depict that exact relationship between the fracturing fluids and proppants used in the various unconventional analysis and their formation characteristics.
- Production data from the various wells should be analyzed to determine which fracturing treatment is most suitable for the formations studied.

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