SELECTION OF FRACTURING FLUID FOR STIMULATING TIGHT GAS RESERVOIRS

A Thesis

by

RAJGOPAL VIJAYKUMAR MALPANI

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2006

Major Subject: Petroleum Engineering

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Approved as to style and content by:

Chair of Committee, Stephen A. Holditch
Committee Members, William D. McCain Jr.
Kenneth R. Hall
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ABSTRACT

Selection of Fracturing Fluid for Stimulating Tight Gas Reservoirs. (December 2006)

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Chair of Advisory Committee: Dr. Stephen A. Holditch

Essentially all producing wells drilled in tight gas sands and shales are stimulated using hydraulic fracture treatments. The development of optimal fracturing procedures, therefore, has a large impact on the long-term economic viability of the wells. The industry has been working on stimulation technology for more than 50 years, yet practices that are currently used may not always be optimum. Using information from the petroleum engineering literature, numerical and analytical simulators, surveys from fracturing experts, and statistical analysis of production data, this research provides guidelines for selection of the appropriate stimulation treatment fluid in most gas shale and tight gas reservoirs. This study takes into account various parameters such as the type of formation, the presence of natural fractures, reservoir properties, economics, and the experience of experts we have surveyed. This work provides a guide to operators concerning the selection of an appropriate type of fracture fluid for a specific set of conditions for a tight gas reservoir.

DEDICATION

To my family

ACKNOWLEDGEMENTS

I would like to thank Dr. Stephen Holditch for his valuable guidance, encouragement, and interest throughout the course of completion of this research project and my advisory committee for their support in completing this project.

I would also like to thank Michael Smith with NSI Technologies; D.J. White, George Waters, Tom Olsen, John Jochen, and Jeff Asbill with Schlumberger DCS; John Spivey with Phoenix Reservoir Engineering; Nicholas Tschirhart with XTO Energy; Tony Martin and Steve Baumgartner with BJ Services Company; Roger Black with IHS Energy; Ray Flumerfelt with Matador Resources Inc.; and Halliburton Services for providing valuable information and feedback.

I thank God for empowering and guiding me throughout the completion of the degree.

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CHAPTER I

INTRODUCTION

Energy Future

As gas production volumes from conventional reservoirs continue to decrease and demand for energy continues to increase, the importance of producing gas from unconventional reservoirs has been magnified. The large volume of gas-in-place combined with higher gas prices, brings unprecedented interest in the unconventional resources for our energy future. Unconventional reservoirs are reservoirs that can not be produced at economic flow rates nor produce economic volumes of oil and gas without assistance from massive stimulation treatments, special recovery processes, or advanced technologies. Typical unconventional reservoirs include tight gas sands, gas shales, coal bed methane, heavy oil, tar sands, and gas hydrates.

All natural resources are distributed log-normally in nature. John Masters and Jim Gray recognized that these principles also apply to oil and gas reservoirs by introducing the resource triangle for such reservoirs[1]. The concept of the resource triangle can be used to describe the distribution of natural resources, such as gold, silver, iron, zinc, oil, and natural gas. As illustrated in Fig. 1, one finds that high quality reservoirs (those that produce at economic flow rates with very little stimulation requirements) will be small targets that can be found with conventional seismic geology. In fact, in most basins, in most petroleum provinces in the world, the main producing reservoirs can be classified as

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This thesis follows the form and style of the *Journal of Petroleum Technology*.

"high" quality or "medium" quality, near the peak of the resource triangle. As one continues to look for gas resources in lower quality rocks, one must combine better engineering technology with geologic expertise to properly locate, perforate, stimulate and produce these low quality reservoirs. The lower quality rocks contain enormous volumes of hydrocarbons-in-place, compared to the smaller, higher quality reservoirs.

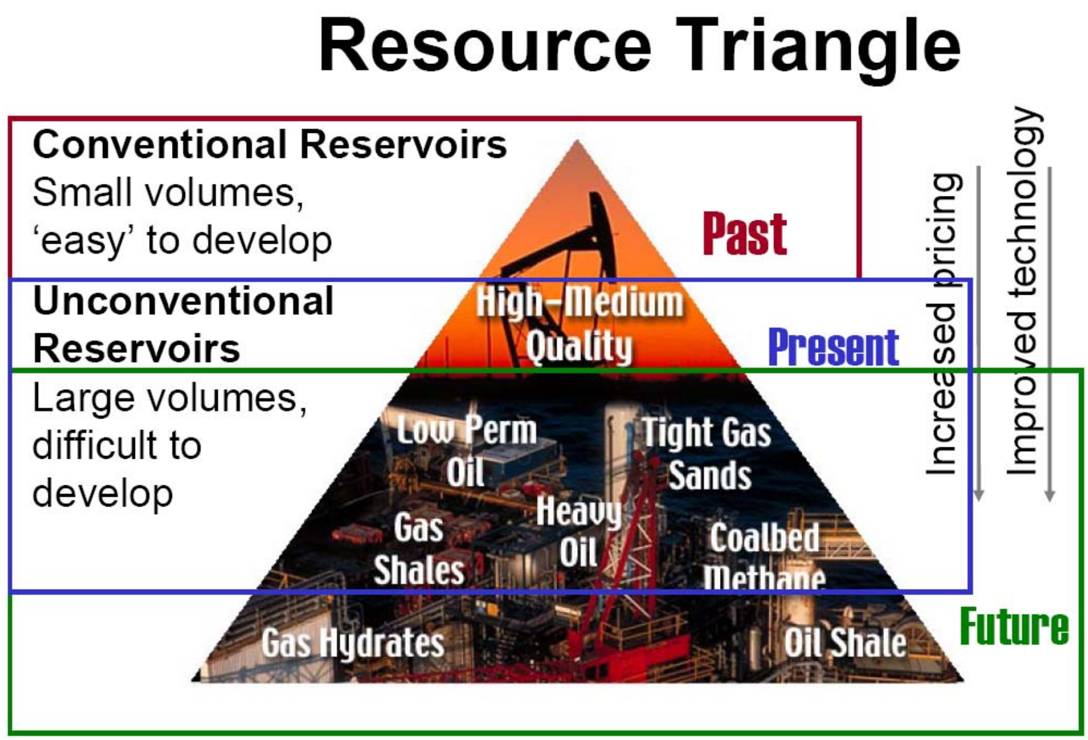

Figure 1: The Resource Triangle (Holditch[1])

With the gap between the energy demand and supply increasing and the decline in production from many conventional reservoirs, the importance of unconventional resources is increasing in basins all over the world. With the successful marketing of natural gas as an "environmentally-friendly" fuel, demand for natural gas will continue to increase in the coming decades. Without question, a significant percentage of the world's energy demand will be satisfied by natural gas.

Tight Gas Sands and Gas Shales – Hot Prospects

In 2001, the total domestic natural gas production in the United States was 19.8 Tcf. Natural gas from unconventional reservoirs contributed 5.4 Tcf. Around 70 % of the unconventional gas production (3.8 Tcf) came from tight gas sands and shales[2]. The present reserves of natural gas in the United States, from all sources, is 189 Tcf. This is the value of proved reserves, which means it will likely be recovered from existing wellbores with existing technology under current economic conditions.

There is also a category in some resource estimates called technically recoverable gas. Technically recoverable means the gas is known to exist and is likely to be produced someday, but the reservoirs have yet to be developed. It is estimated that there is 441 Tcf of technically recoverable gas in 15 tight gas basins shown in Fig. 2 and 75 Tcf of technically recoverable gas in 8 gas shale basins shown in Fig. 3 in the United States[2].

Key to producing gas from tight gas reservoirs and gas shales is the development of new technology. New technology is required to evaluate the formation so we can locate the most permeable gas-bearing layers within a formation and drill the well efficiently, correctly and economically. Better technology is also required to complete, stimulate, and produce the well correctly and efficiently. Because tight gas reservoirs are usually composed of rocks with very low porosity, and these reservoirs are marginally economic to produce unless the optimal stimulation treatment is both designed and pumped, the importance of using the best technology – every step of the way – is magnified.

Tight gas is the terminology used to refer to low permeability reservoirs that produce mainly dry natural gas. A valid definition of tight gas is as follows: "A tight gas reservoir can not produce commercial volumes of gas at economic flow rates unless massive stimulation treatments are successfully designed and pumped[1]". Most of these reservoirs are sandstone, but significant volumes of natural gas are produced from low permeability carbonates, shales and coal seams. Every basin in the world that is currently producing oil or gas in significant quantities will also contain oil and gas resources in low permeability reservoirs, because all natural resources are distributed log-normally in the nature.

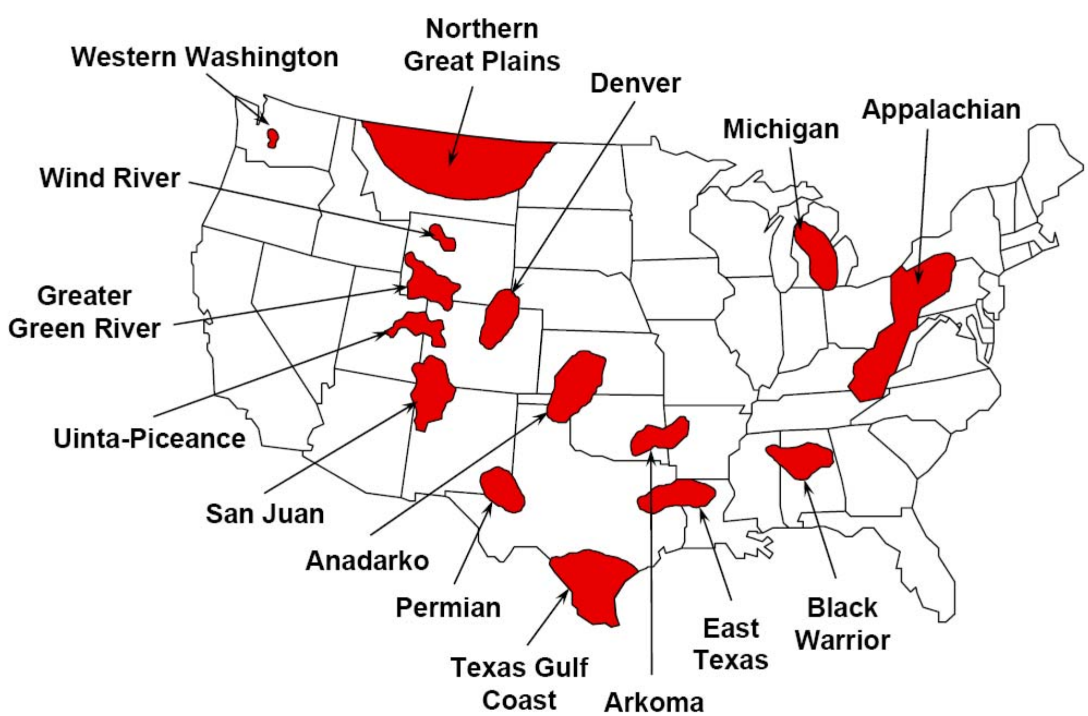

Figure 2: Major U.S. Tight Gas Sands Basins (GRI)

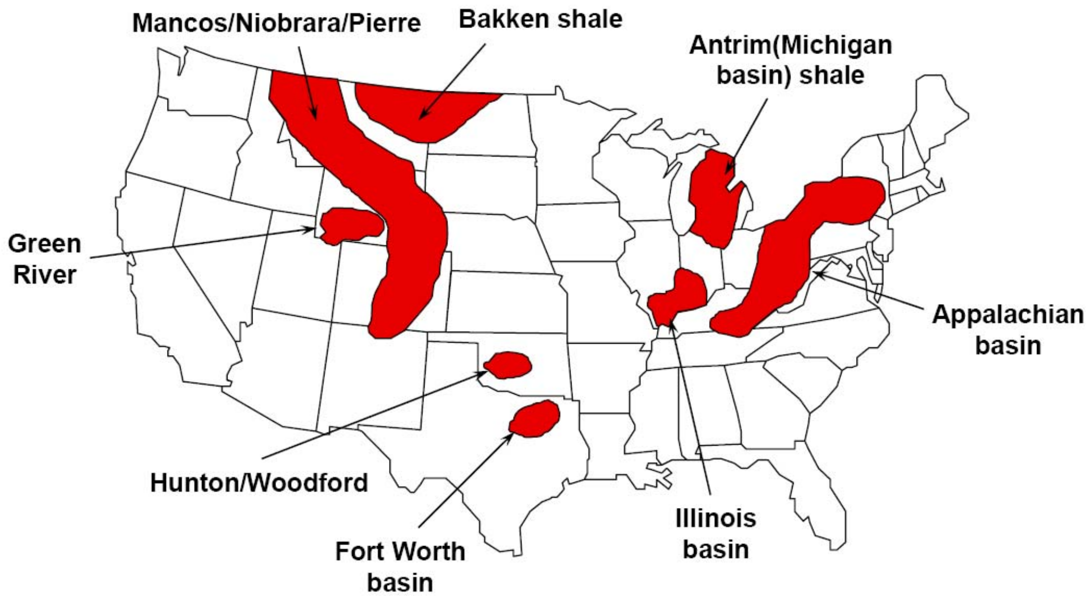

Figure 3: Major U.S. Gas Shale Basins (GRI)

Hydraulic Fracture Stimulation

Hydraulic fracturing plays a key role in producing unconventional gas resources. The concepts concerning hydraulic fracture stimulation are demonstrated in Fig. 4[3]. In the first stage, a small quantity of fluid is pumped down the well, known as "pre-pad," to fill up the well, start pumping into the well, break down the formation, and make sure the mechanical condition of the well is satisfactory. Then, a neat fluid known as "pad" is pumped. The hydraulic pressure generated by pumping the pad causes the fracture to propagate into the reservoir. The pad fluid also cools down the wellbore and the rock near the fracture walls. Subsequently, a slurry consisting of fluid and proppant is pumped in the fracture. The primary purpose of the propping agent is to hold the fracture open upon completion of pumping and provide a conductive path for gas to flow to the wellbore. High fluid viscosity is required to carry proppants deep into the fracture and prevent proppant settling. The last and most important stage of fracturing is to break the fluid and reduce the viscosity using additives so the fluid can flowback and the well can cleanup. The fracture must close on the proppant to prevent settling and to create a long conductive fracture.

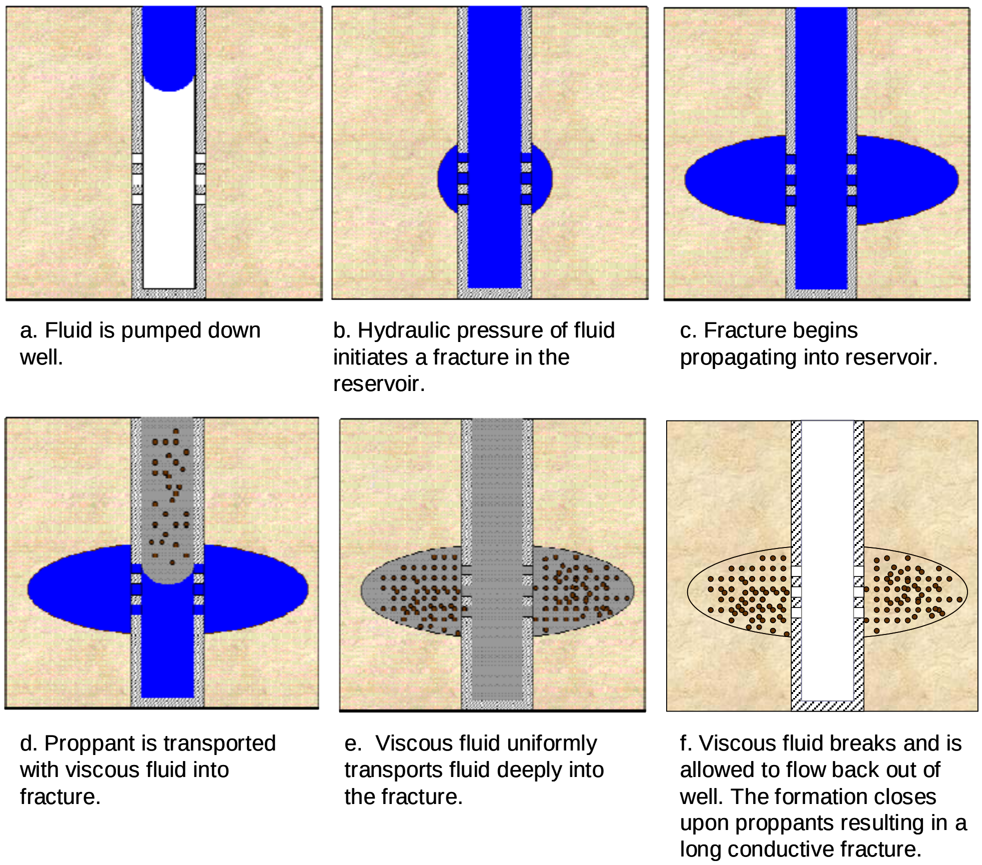

Figure 4: The Hydraulic Fracture Stimulation Process (Tschirhart[3])

Hydraulic fracture stimulation can significantly improve the production performance of wells in tight gas reservoirs because a long conductive fracture changes the flow pattern in the reservoir. Fig. 5 illustrates why hydraulic fracturing works. Fig. 5a shows radial flow of gas to the wellbore which occurs prior to a fracture treatment. All of the gas must converge to a very small area, resulting in large pressure gradients near the wellbore. Fig. 5b shows the early time linear flow into the fracture that occurs after a successful fracture stimulation treatment. In the literature, it is referred as “flush production”. In many cases, the well makes enough gas during the flush production period to pay out the costs of the fracture treatment, and sometimes, the entire cost of the well. Finally, as shown in Fig. 5c, the well will produce under pseudo-radial flow. Usually, the flow rates are low during pseudo-radial flow, but the well can produce gas for many years if the stabilized flow rate is above the economic limit. Conventional perception in designing a hydraulic fracture treatment would suggest that successful stimulation of tight gas sands requires creation of a long (several hundred feet or more) and conductive fracture. To achieve a long, conductive fracture, we must pump large volumes of proppants at high concentrations using large volumes of fluids that are adequate to transport proppant deeply into the fracture.

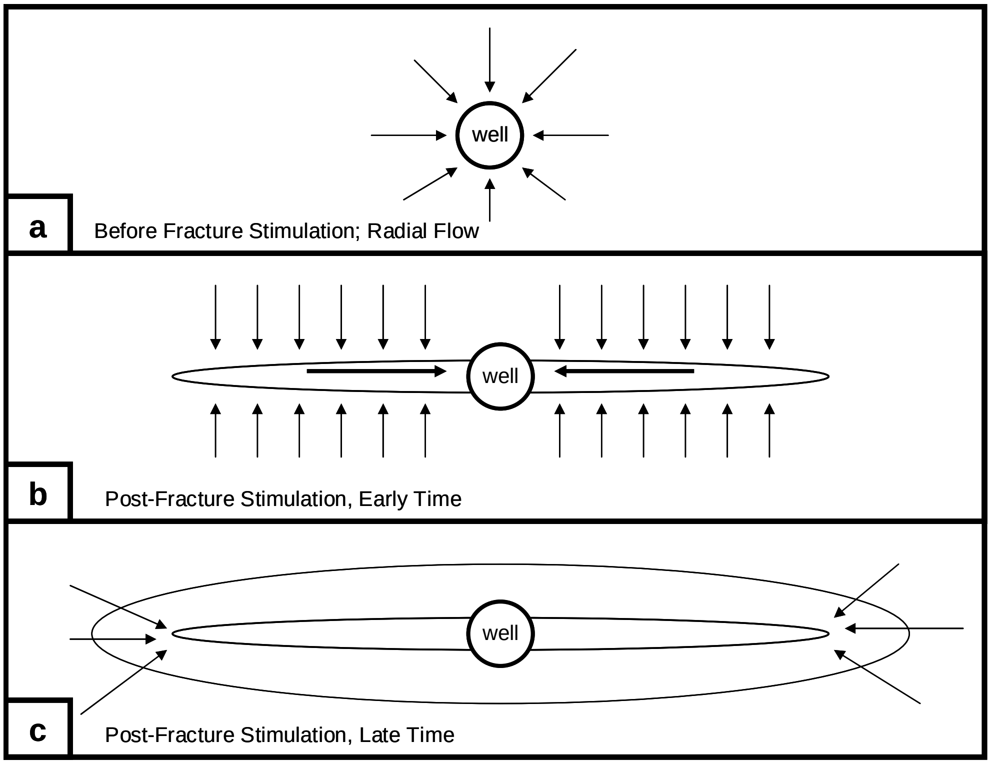

Figure 5: Illustration of Flow Paths for Fractured and Non-Fractured Wells (Tschirhart[3])

An ideal fracture fluid would have enough viscosity to transport proppant deeply into the fracture at a reasonable cost relative to other fracture fluids. The fluid should have low to moderate friction properties and should be stable at the reservoir temperature during the pumping time. After pumping ends, the fluid should break down to a low viscosity fluid to enhance the cleanup leaving little to no residue in the fracture that would reduce fracture conductivity.

A poor fracture treatment is one that does not create an effective fracture. The failure of a fracturing treatment can be caused by fracturing out of zone, poor choice of proppant or fracture fluid, poor reservoir characterization, proppant settling, inefficient fracture cleanup, and/or damage to the fracture. For one or more of these reasons, a poor fracture treatment design does not result in a fracture that is long enough or conductive enough to optimize gas recovery from the reservoir.

History and Development of Hydraulic Fracture Stimulation

Virtually all wells completed in tight gas sands and shales require hydraulic fracture treatments to achieve economic gas flow rates and recovery. The very first hydraulic fracture treatment was pumped in the Hugoton gas field in July 1947[4]. Four gas-productive limestone layers were fracture stimulated using gasoline that was gelled with napalm. By the mid-1960's, the use of large volumes of low-cost water as the fracture fluid was the normal method to stimulate many low permeability gas wells. In the early 1970's, viscous fluids emerged as improved fracture fluids that were capable of carry higher concentration of proppants (4-5 ppg). Over the years, the technology has improved so that in many cases we can create and prop-open long conductive fractures that allow us to economically produce many unconventional gas reservoirs.

Hydraulic fracture treatments in the 1980's and 1990's used water gelled with polymers that could be cross-linked so that large volumes of propping agents at high concentrations (8-10 ppg) were commonly pumped. In many cases, these treatments work very well, especially at high temperature (> 300 ^{0}F) where stabilizers must be used in the gelled fluid. At lower temperatures, 200 ^{0}F or less and for low reservoir pressures, the industry typically uses foam fluids. Foam fluids will break and clean-up when the bottomhole pressure is reduced during flow back.

When the formation temperature is between 200-250 ^{0}F, we can still use cross-linked gel fluids, but we must carefully design the fluid so that sufficient breaker is used to break the fluid after the treatment is completed. If the appropriate type and amount of breakers are not used, when the BHT < 250^{0}F, then we run the risk of causing damage to the fracture because of unbroken fracture fluid. Under certain conditions, minimal effective stimulation may result, sometimes leading to sub-economic wells[5], especially if fracture fluid clean-up problems occur.

In some medium temperature reservoirs, like those in the Cotton Valley formation in East Texas, it was observed that some cross-linked fracture treatments were not all that successful in creating long fractures, as designed. As an experiment, some operators began pumping water fracture treatments trying to see if less expensive fracture treatments could provide adequate stimulation.

Water fracture treatments were initially designed to generate fractures by injecting low viscosity fracturing fluid composed of water, clay stabilizers, surfactants, and friction reducer. Most of the proppant is pumped at concentrations of around 0.5 – 1.0 ppg. Near the end of the treatment, concentrations of proppant are ramped to a maximum of 2 ppg to achieve higher conductivity near the wellbore[6]. The main advantage of water fracture treatments is that they cost less than a comparable gel fracture treatment, because less polymer, fewer chemicals, and less propping agents are pumped. However, since lower proppant volumes and concentrations are used, issues concerning effective fracture length and conductivity must be analyzed.

Miceller fluid is created by adding an electrolyte, such as quaternary ammonium salt, to water along with a special surfactant which creates long, worm like micelles. The micelles create viscosity in a similar way to have long-chain polymers create viscosity in gel fluids. Miceller fluid has a lot of appeal as it develops reasonable viscosity and has reasonable proppant transport without having to use polymers. In this case, hydrocarbons (oil or gas) are the breaker system, so when we produce hydrocarbons it breaks the micelles and the fluid cleans up. Miceller fluids have been used for several years. They have not dominated the market yet, because there are temperature limitations and there are issues involved with the cost of surfactant. However, if surfactants can be developed with higher temperature stability and the costs can be reduced, then miceller fluids could be the ideal fluid for many tight gas reservoirs.

Recently, a new kind of treatment, called as hybrid fracture treatment has been used by some operators with reasonable results. A hybrid fracture treatment offers a mixture of the benefits of a cross-linked gel fracture treatment and a water fracture treatment. In a hybrid fracture treatment, slick water is pumped as the pad fluid to create the fracture geometry with theoretically little hydraulic width development and minimal out of zone height growth. Subsequently, a more viscous cross-linked gel is pumped which creates fracture width and carries proppant into the fracture. In one field, the hybrid fracture stimulation technique seems to generate longer effective fracture half-lengths and larger effective fracture conductivities than either gel fracture treatments or water fracture treatments[7].

The current understanding of when and where to apply various types of stimulation treatments such as gel fracture treatments, water fracture treatments, hybrid fracture treatments, miceller fracture treatments, or foam fracture treatments is limited. In "medium" temperature reservoirs, it appears that hybrid fracture treatments or miceller fracture treatments may provide the best stimulation alternative.

In this study, we have evaluated each stimulation treatment type using information from the petroleum engineering literature, numerical and analytical simulators, surveys of experts, and statistical analysis. As a result of this study, we have developed a procedure for selecting a stimulation treatment fluid for a tight gas reservoir. One motive of this work was to describe when water fracture treatments should and should not be used.

Objectives

The objectives of this research are as follows:

- Review the literature to determine the reservoir conditions where the following treatments appear to work well:
  - Water fracture treatments
  - Crosslinked-gel fracture treatments
  - Hybrid fracture treatments
  - Miceller fracture treatments
  - Foam fracture treatments
- Analyze production data in from a sample of Cotton Valley wells in East Texas where different types of fracture fluids have been used to determine if

the production performance of the wells can be corrected to the type of fracture fluid used.

- Analyze production data from a sample of Cotton Valley wells in East Texas using an analytical simulator to see if we could compute values of effective fracture lengths and drainage area that can be correlated with how the well was simulated.
- Use a fracture propagation model to investigate conditions where water fracture treatments might work in tight gas sands.
- Develop a questionnaire and sent it to industry experts to learn how they select a fracture fluid for a specific set of reservoir conditions in tight gas sands.
- Develop a flow chart that can assist an engineer to select the appropriate fracture fluid for a tight gas sand reservoir.
- Develop guidelines on when water fracture treatments should and should not be pumped to stimulate gas wells.

CHAPTER II

LITERATURE REVIEW

Evolution of Water Fracture Treatments

In 1986, slick water treatments were reborn from the 1960s to fracture stimulate horizontal wells completed in Austin Chalk formation[3]. A significant increase in production performance was clearly documented in the literature because of water fracture treatments in the Austin Chalk. The theories used to explain the success of water fracture treatments in the Austin Chalk include imbibition, gravity effects, opening multiple fractures, skin removal, cleanup of old fracture fluid residue, dissolution of salt, reservoir repressurization, and rock mechanics effects[8]. We believe that much of the benefits cam from the removal of old gel, that never broke when the well was originally fracture treated and had been plugging the natural fractures around the wellbore for years.

In the mid 1990's, a few operators started pumping water fracture treatments in the Cotton Valley sands of the East Texas basin partly because of success in the Austin Chalk formation. It was hypothesized that gel fracture treatments in the Cotton Valley were not cleaning up effectively resulting in short effective fracture lengths. The early water fracture treatments pumped in the East Texas basin primarily used slick water as the fracturing fluid without any linear or cross-linked gel, with very little proppant. Higher injection rates were used during the water fracture treatments to help transport the propping agents and minimize leak-off [9]. The costs of slick water treatments were lower than the gel fracture treatments, which was one of the main reasons operators began to switch to water fracture treatments.

By 1997, water fracture treatments were being pumped in the naturally fractured Barnett shale[6, 9]. It was reported that in the Barnett shale, water fracture treatments resulted in better stimulation as compared to gel fracture treatments. The success of water fracture treatments in the Barnett shale is well documented in the literature. The success is considered to be related to permeability and porosity, gross thickness, and the existence of a natural fracture network[10]. A common aspect of the Barnett shale and the Austin Chalk is the existence of a natural fracture network.

Water fracture treatments have been used in a lot of different reservoirs in the past few years. The success of water fracture treatments, in terms of the effective propped fracture length and productivity index increase, can be questioned in many reservoirs. What seems clear in some reservoirs is that water fracture treatments are comparable to gel fracture treatments, but cost less. Thus, the economics of using water fracture treatments would be better than gel fracture treatments in such cases.

Water fracture treatments use slick water as pad to create the initial fracture geometry, followed by 20 to 30 lb/1000 gal linear gel for the proppant-laden stages. Water fracture treatments must be evaluated on both a technical and an economical basis. Clearly, water fracture treatments work well in naturally fractured reservoirs like the Austin Chalk and Barnett shale. However, it is not clear whether water fracture treatments provide optimal stimulation in medium temperature, tight gas sands that not naturally fractured, such as the Cotton Valley formation in East Texas.

What Is Behind the Success of Water Fracture Treatments?

The petroleum engineering literature suggests several hypotheses behind the success of water fracture treatments. Generally, the success of water fracture treatments in many cases depends upon the existence of existing natural fracture systems and their favorable response to the injection of fracture fluid and proppant. Other reasons why water fracture treatments work well include imbibition, the creation of a wide fracture network due to opening of multiple natural fractures, shear dilation and asperities, and the absence of cleanup problems in the fracture because very little gel is used during the treatment.

Imbibition

Imbibition is a process by which the wetting phase displaces the non-wetting phase. For water wet naturally fractured rocks, water will displace oil and gas from the pores in the matrix expelling the oil and gas into the natural fractures where it can flow to the hydraulic fracture and eventually to the wellbore. Numerous studies have shown that significant imbibition occurs in the matrix of Austin Chalk cores. Analysis of water injection in the low permeability, naturally fractured Spraberry formation has indicated importance of imbibition in reservoir performance[8].

Creation of a Fracture Network

Slick water pumped at very high injection rates has the ability to open existing fractures in the formation and, perhaps, create new fractures. The created fracture geometry in these naturally fractured formations may be very complex[3, 8]. Many times a network of fractures will be created, rather than a single, planar fracture as we expect when treatments are performed in homogenous rock. The process may induce fracture offset and branching, thus enhancing the permeability of the reservoir. Microseismic mapping of water fracture treatments often indicate the creation of extremely complex fracture networks which results in an increased surface area of created fracture[11]. Fig. 6 portrays the concept of simple fracture, complex fracture and extremely complex fracture.

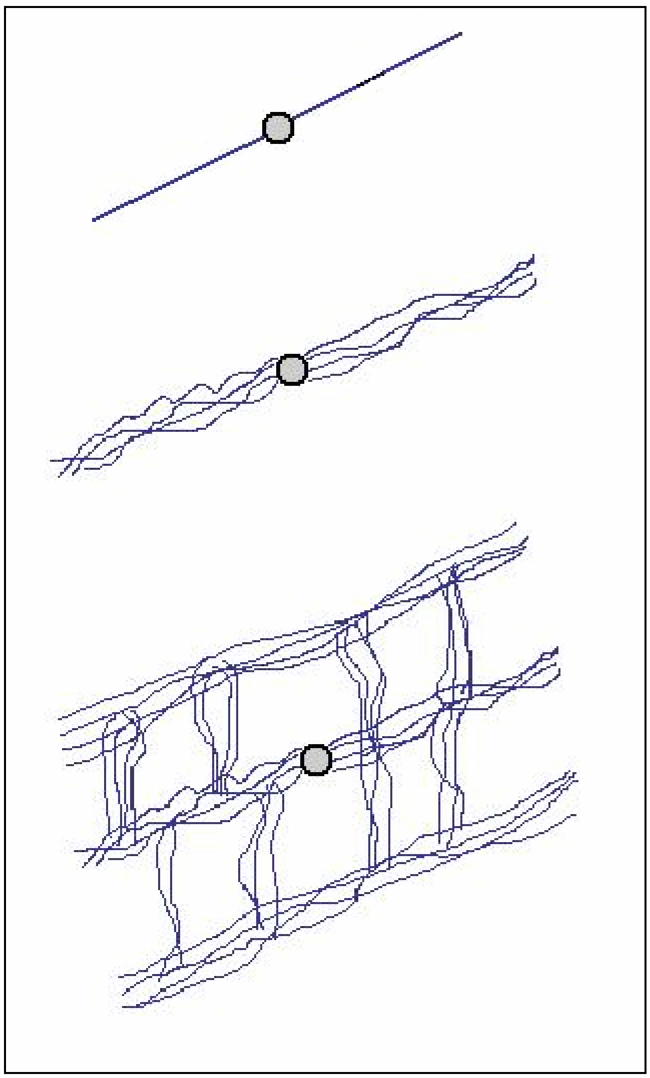

Figure 6: Fracture Geometry of Hydraulic Fractures Ranging from a Single, Planar Fracture to a Wide Fracture Network

Shear Dilation and Asperities

When a fracture opens (either a created fracture or a natural fracture) shear forces or asperities may create a situation where the fracture does not completely heal when the pressure in the fracture is reduced to a value less than the in-situ stress. Natural mismatches and asperities may be created when shear forces displace the fracture face. Propagating fracture fluid can open existing faults and planes of weakness by shear slippage. The fracture created due to shear slippage and dilation is illustrated in Fig. 7. During pumping, the pressure inside natural fractures is elevated and thus the stress distribution around the fracture changes. Beyond a threshold pressure, rock material around the fracture fails by sliding, instead of opening as considered in conventional hydraulic fracturing. At the end of pumping, asperities of the rough fracture surfaces may not come back to the original position, and thus the fracture may remain open[12].

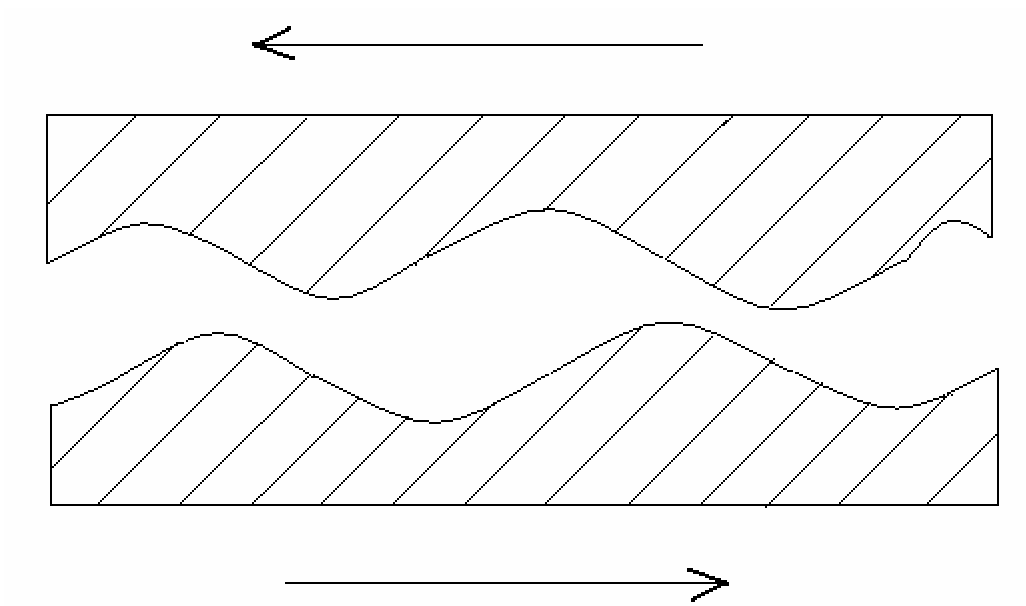

Figure 7: Created Fracture due to Shear Dilation

Absence of Unbroken Fluids and Proppants

Water fracture treatments primarily use slick water with little or no polymer without any cross-linker so that the fluid does not have to be broken to flow back and cleanup. The created fracture remains clean due to lack of unbroken polymer and/or degraded polymer. In addition, the fracture face remains un-damaged and open to gas flow unless fluid loss additives were used in the fluid. The interaction of the proppant with the natural fractures appears to have hindered fracture growth, and allowed for the re-direction of fluids in the reservoir[13].

Evaluation Studies

Numerous papers have been published addressing the evaluation of fracture treatments in tight gas sands over last decade. Mayerhofer *et al.*[9] compared early production performance of water fractured wells and gel fractured wells. They concluded that gas production from water fractured wells was equivalent to gas production from gel fractured wells, and because water fracture treatments cost about half as much as gel fracture treatments that water fracture treatments provide for better economics.

Mayerhofer and Meehan[6] also conducted a statistical comparison using first 6-month of cumulative gas production for approximately 90 wells. They concluded that, in general, water fracture treatments perform at least as well as gel fracture treatments, and at substantially lower costs. They also mentioned that the eventual production performance can only be evaluated after several years of production. Using early production data makes it difficult to evaluate fracture quality, because they did not have any pre-fracture and post fracture pressure buildup data to analyze.

Poe *et al.*[14] used production data history matching and pressure-transient analysis to analyze well performance of over 200 wells completed in various tight gas sands in North America. The results of their study clearly demonstrate that tight gas sands need large proppant volumes and high viscosity fluids to properly place the proppant to achieve long effective fracture lengths and adequate fracture conductivities to improve the productivity of the wells. The authors presented evidence that cross-linked gel fracture treatments carrying large volumes of proppant results in better wells that what was achieve with water fracture treatments.

England *et al.*[15] used specialized diagnostics, history matching, and production type curve analyses for over 100 wells completed in Cotton Valley sands to look at gel fractured wells versus water fractured wells. They used daily production and pressure data for all the wells. Water fractured wells resulted in similar production performance as gel fractured wells when compared on the basis of one-year cumulative gas production without giving any compensation for difference in flowing tubing pressure, initial reservoir pressure, and differences in reservoir quality. These results support the general belief that water fractured wells produce almost equal to gel fractured wells at lower costs. However, when they normalized the data to compensate for reservoir quality and flowing tubing pressure differences, the average gel fractured well produced more gas than average water fractured well.

Later in the 1990's, a consortium of East Texas operators conducted a microseismic study to evaluate hydraulic fracture growth of gel fracture treatments and water fracture treatments. Mayerhofer *et al*.[11] reported that longer "created" fracture lengths were observed for gel fracture treatments as compared to water fracture treatments. The results of pressure buildup analysis shows that creation of very short, low conductivity fractures for water fracture treatments. They further concluded that the best performing well is the gel fractured well while both water fractured wells were producing at a substantially lower rate.

Fredd *et al*.[16] conducted a series of laboratory experiments on fractured cores from Cotton Valley sands in the East Texas Basin. The study shows that shear displacement is essential for surface asperities to provide residual fracture width and sufficient conductivity in the absence of proppants. The asperity dominated conductivity depends on several formation properties and is unpredictable. They further concluded that high strength proppants can be used to provide higher conductivities for water fracture treatments.

Rushing and Sullivan[5] conducted a study to compare the stimulation effectiveness of water fracture treatments and hybrid fracture treatments. Short-term pressure buildup analysis and long term gas production analysis was performed on 18 wells in the Bossier sands. They concluded that on average, hybrid fracture treatments will generate longer conductive fractures when compared to water fracture treatments.

Sullivan *et al.*[7] used chemical tracers to extensively quantify the polymer recovered during fracture fluid cleanup. They demonstrated that fracture fluid recovery (and polymer volumes) can be improved by selecting the proper fluid and applying aggressive breaker schemes. They further concluded that application of strong oxidizing gel breakers in the prepad can significantly enhance cleanup of cross-linked gels in the Bossier sands.

Dawson *et al.*[17] proposes a new highly exclusive gaur gum fluid with lower polymer loading and efficient rheological performance, proppant transport, fluid loss control and cleanup. They demonstrated that under certain circumstances, borate cross-linked gel can provide efficient cleanup because of the reversible nature of the borate-guar crosslink junctions. With increasing temperature or decreasing pH, the degree of cross-linking is reduced which contributes to improved fracture conductivity.

Harris *et al.*[18] shows that how metal and borate cross-linked fluids, linear gel fluids, and surfactant gel fluids can support proppant transport. The capability of polymer based fluids to transport proppant depends upon the degree of crosslinking, the breaker system, the shear history, and the volumetric average shear rate. Proppant transport is related to fracture fluid rheology, wellbore and fracture geometry, pumping rate, proppant size, proppant concentration, and specific density of proppants. They demonstrated two effective breaking mechanisms which were oxidizing breakers and acid hydrolysis for metal-crosslinked fluids. Fig. 8 shows effect of acid hydrolysis on a polymer fluid that can be crosslinked from pH 5 to 10 where the fluid can be readily stabilized but acid hydrolysis will eventually break it down. The fluid behavior will change from elastic to viscous, allowing proppant to settle down. (Volume-average viscosity (VAV) is a product of fluid viscosity, particle concentration and cup PRM.)

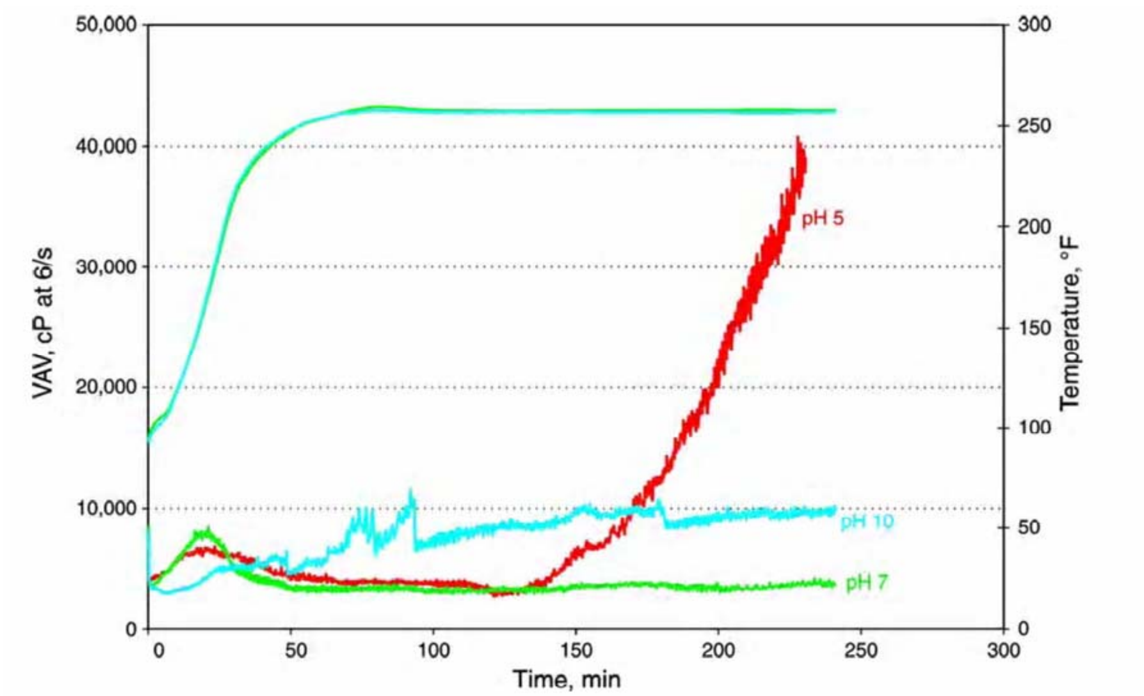

Figure 8: Effect of Acid Hydrolysis on Cross-linked Polymer (Harris *et al.*[18])

Recently, Mayerhofer *et al.*[19] described an integrated approach to fracture stimulation using microseismic fracture mapping, production performance, and pressure-transient data in the East Texas basin. They compared production performance of water fractured wells with newly proposed linear gel hybrid fractured wells. The study indicates that the fractures in the Cotton Valley are contained essentially in a single plane, unlike the fractures commonly seen in the Barnett shale, where wider fracture networks have been observed. They further suggested creation of elongated cigar-like drainage area. Fig. 9

portrays early production performance comparison where it is evident that linear gel hybrid fracture treatments perform significantly better than water fracture treatments.

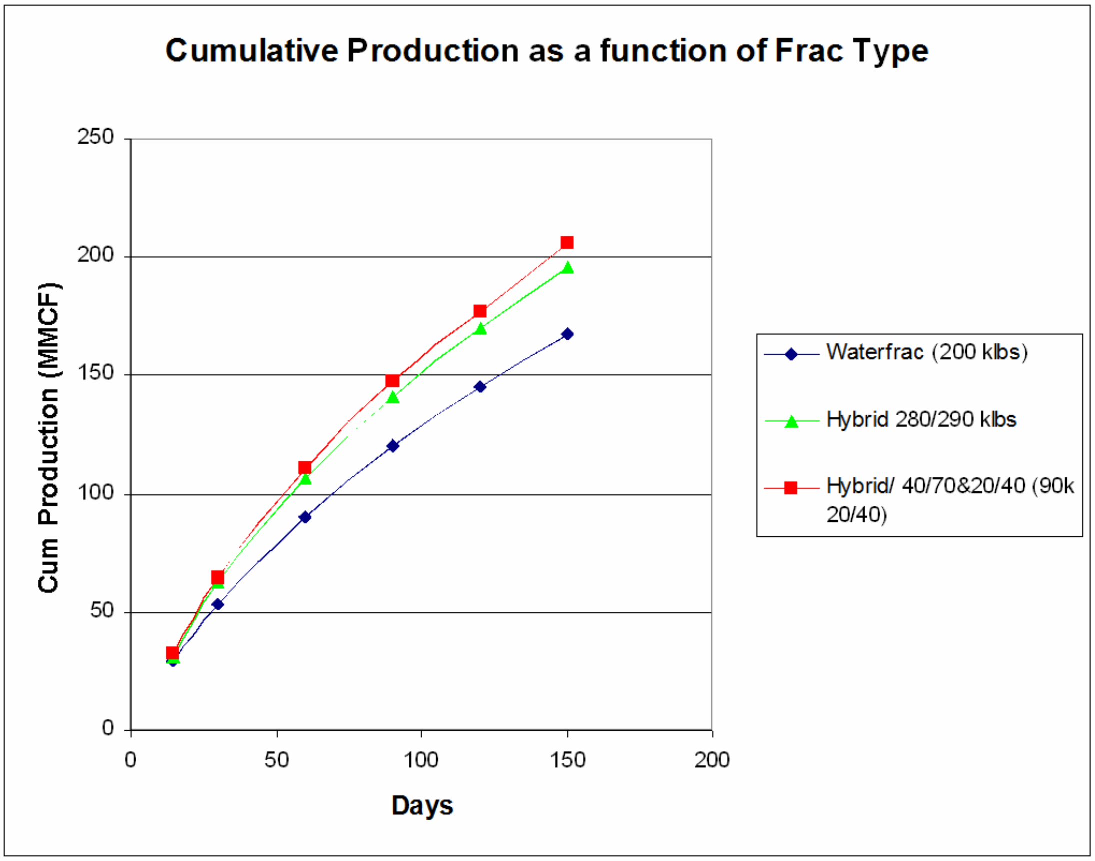

Figure 9: Comparison of Early Time Cumulative Gas Production (Mayerhofer *et al.*[19])

Formations: Successful Gel Fracture Treatments

Holditch and Ely[20] compared medium proppant concentration fracture treatments with low proppant concentration fracture treatments using 6-month and 2-year production data in several deep, high temperature reservoirs. The comparison was based on productivity index of wells after successful stimulation. To normalize the difference in net pay, permeability and porosity, they categorized wells using permeability-thickness product and porosity-thickness product. One of the formations analyzed was the Vicksburg sands in South Texas.

Vicksburg Sands, South Texas
BHT = 300^0F
Natural Fractures = None

At early time, the production performance of all the wells was similar regardless of the type of fracture fluid used to stimulate the well. However, over time, the wells treated with gel fluids carrying larger volumes of proppant outperformed the lower proppant concentration treated wells (the water fracture treatments) as measured by the sustained higher productivity indices. The success of the medium proppant concentration treatment was attributed to pumping more proppant and obtaining wider, more conductive fractures. They concluded that pumping large treatments and higher proppant concentrations is the key to effectively stimulate tight sands, when the temperature is high enough to clearly break the gel so it can cleanup.

Tschirhart[3] described post fracture build-up tests and production data history matching to evaluate the performance of high proppant concentration fracture treatments and medium proppant concentration treatments in the Wilcox-Lobo sands in South Texas.

Wilcox-Lobo Sands, South Texas
BHT = 270 – 300^{0}F
Natural Fractures = None

The high proppant concentration treatments pumped around 3 million pounds of proppant and the medium proppant concentration treatments pumped around 350,000 pounds of proppant. The high proppant concentration treatments achieved longer fracture lengths which substantially, increased reserves and deliverability of the wells. They further concluded that higher proppant volumes and concentrations result in creation of highly conductive, longer fractures with increased drainage area of the well, when the gel clearly breaks and cleans up.

Fracture Propagation

A fracture propagation model mathematically relates the injection rate of slurry, the time of injection, and fluid leak-off with created fracture dimensions such as length, width, and height. Two dimensional (2D) linear models were developed in the early 1960's. These 2D models assumed a constant fracture height through out the treatment. The models take into account various physical processes such as viscous fluid flow, fluid leak-off, elastic deformation, fracture propagation, and some also included equations for proppant transport in the fracture[4].

The most important 2D models were published by Howard and Fast[4], Perkins and Kern[21], Geertsma-de Klerk[22], Nordgren[23], and Daneshy[24]. The first 2D model was Howard and Fast[4] model which assumed a rectangular geometry for fracture propagation as well as assume constant fracture width along with fracture height.

Perkins and Kern[21] published a model that included changes in fracture width as a function of position in the fracture. They used the equation of an ellipse to calculate width variation along the wellbore vertically and down the fracture horizontally. They did not include fluid leak-off. Later, Nordgren[23] used the Perkins and Kern geometry, and added fluid leak-off and developed a model that is commonly referred as the PKN model.

Khristianovitch-Zeltov[4], Geertsma-deKlerk[22], and Daneshy[24] (GDK) all assumed fracture width is a function of length and not a function of height, so they basically assumed rock stiffness is present only in the horizontal plane. They assumed constant fracture height and did account for leak-off. In general, given the same input data, the GDK model will predict wider, shorter fracture than the PKN model.

All 2D models assume fixed fracture geometry, and usually assume that the fracture height is constant. The assumption of constant fracture height often results in calculated fractures that are than what we observe in the field. In reality, fractures tend to grow up, down, and out and the fracture height varies down the fracture length.

To better simulate fractures, the industry has developed three dimensional, planar models (3D). These 3D fracture propagation models were developed to better model fracture height growth with time and to more accurately predict the fracture dimensions[4]. These 3D models also let us better predict the propped fracture dimensions by doing a better job of modeling proppant transport.

Pseudo 3D fracture propagation models (P3D) incorporate variations in fracture height along the fracture using local fracture pressure[4]. The model normally uses only one-dimensional (1D) fluid flow, thus 1D proppant transport in the fracture but proppant settling is considered. A P3D model provides quick answers with reasonable accuracy for many situations.

A fully 3D model of fracture propagation provides even more realistic predictions of fracture geometry and dimensions. The fracture shape evolves with both time and space. The 3D model uses rock mechanics equations solved by finite element methods and 2D fluid flow equations solved by finite difference models. This model requires a detailed description of all rock layers to full advantage of the model capabilities. Fully 3D models require high speed computers and, sometimes, substantial CPU time to simulate many situations. The lack of input data and the additional computing time limits the use of fully 3D models in the industry.

Mack and Myers[25] used a fully 3D fracture propagation model to simulate fractures using different sized proppants and different fracture fluids. The fracture parameters obtained from simulations were then compared based on well productivity to find out optimal size of proppants and optimal fracture fluid for Devonian sands.

Mack and Myers[25] selected two wells, one with strong lower barrier and other with not a good lower barrier to demonstrate applicability of crosslinked gel, gelled water, and slick water. Net Present Value (NPV) and Discounted Return on Investment (DROI) were calculated for each scenario to decide optimal fracture fluid for both the wells. The authors apparently did not consider the effects of various factors such as matrix permeability, formation modulus, fluid leak-off, and required fracture lengths.

Their study revealed that bigger or more proppant is not necessarily better and showed that placement of proppants is the key to effectively stimulate Devonian sands. Their study demonstrated that when a strong lower barrier is present, then gelled water can be used to transport sand into the fracture by essentially washing it down the fracture. However, when the lower barrier is weak, it is better to use cross-linked gel because the propping agents will settle in the fracture below the net pay if only water is used to pump the treatment. The study also shows that small mesh sand (40-70) improves well potential because of deeper placement attained, because proppant settling rates in a newtonian fluid are a function of the diameter of the proppant squared. As such, in general, 40-70 mesh proppant settles four times slower than 20-40 mesh proppant.

CHAPTER III

METHODOLOGY

In this research, we have performed the following tasks, all of which are described in more detail below:

- We conducted a thorough literature review to determine optimum reservoir conditions for using various types of facture fluids;
- We evaluated field data from a sample of Cotton Valley wells in East Texas to determine if production data can be used to determine which fracture fluid provides better stimulation;
- We analyzed production data from a sample of Cotton Valley wells in East Texas using an analytical simulator to see if we could compute values of effective fracture lengths and drainage area that corrected with how the well was stimulated;
- A fully 3D fracture propagation model was used to determine necessary reservoir conditions for pumping successful water fracture treatments in medium temperature reservoirs like to Cotton Valley sands;
- We developed a questionnaire and sent it to industry experts to learn how they select a fracture fluid for a specific set of reservoir conditions;
- We developed a flow chart to help engineers select the appropriate type of fracture fluid for a specific set of reservoir conditions; and
- We developed guidelines on when water fracture treatments should and should not be pumped to stimulate wells.

Review of Literature

We reviewed the literature to determine what are the different fracture stimulation treatments and what are the optimum reservoir conditions required for each fracture treatment to successfully stimulate the wells. We studied various formations to determine the success when using different types of fracture fluids. The reasons behind either success or failure were studied to determine the applicability of each type of fracture fluid in specific set of conditions.

Analysis of Field Data

The primary purpose of the field data analysis was to evaluate the gas flow rates from a sample of Cotton Valley wells in the East Texas that have been stimulated with either cross-linked gel fracture treatments or water fracture treatments. We believe a detailed analysis of the production data will help us determine optimal fracture treatments for specific conditions. We decided to look primarily at the Carthage field in the East Texas because it is one of the largest and oldest fields with over 2700 wells completed, and also a lot of water fracture treatments had been pumped in the field. This field has a good distribution of various sized fracture treatments using different types of fracture fluids.

A typical well completed in this field is stimulated with two to four stage fracture treatments. Usually, the producing intervals are fracture stimulated one at a time, using bridge or sand plugs starting at lowermost interval, usually the Taylor sand. Then all of the hydraulically fractured intervals are commingled and placed on production after flowback.

For this study, a particular area in the Carthage field was considered and was described in the thesis by Tschirhart[3]. The area of interest spans about 10 miles east-west and about 10 miles north-south as shown in Fig. 10 Fracture treatment details were available for approximately 575 well in the selected area out of which 240 wells were selected for the study. We have taken the analyses first published by Tschirhart[3] and have re-analyzed the data in a couple of different ways.

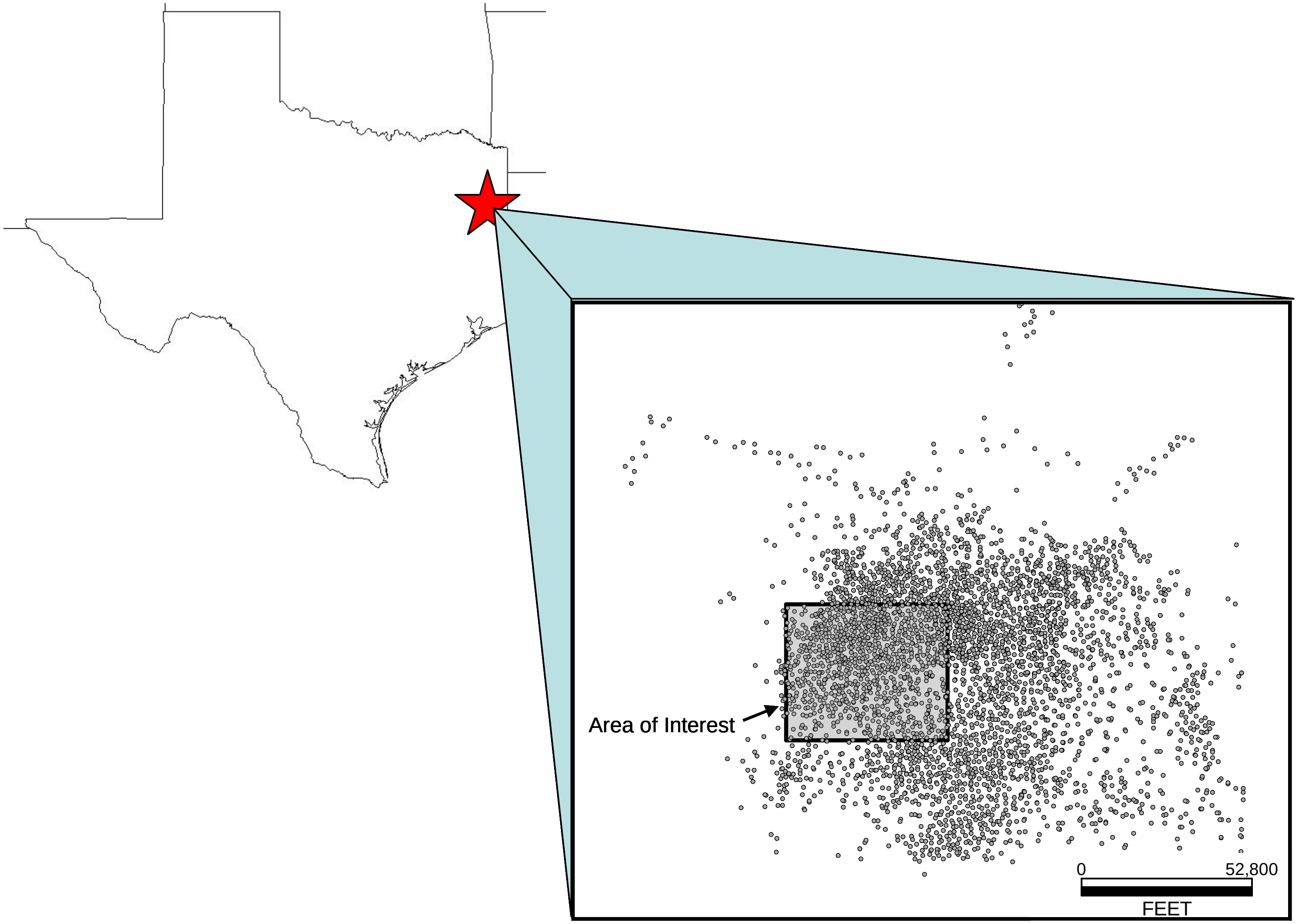

Figure 10: Area of Interest in the Carthage Field (Tschirhart[3])

The wells were grouped on the basis of proppant concentration calculated using total amount of fluid and proppant pumped for all stages for comparison. The two categories are shown in Table 1. Each category was assigned a color which was used through out this study to distinguish the fracture treatments.

Table 1: Treatment Type Categories

Medium Proppant Concentration (MPC)	**2 -6 ppg**
Low Proppant Concentration (LPC)	**0 - 2 ppg**

Gas production began in early 1980s from the Carthage field. During the course of last 25+ years, the field has been aggressively developed as the well spacing has been systematically reduced form 160 acres to 20 acres in some parts of the field. As infill drilling has occurred, it is clear that many of the infill wells have encountered low pressure zones that have been partially depleted. Tschirhart[3] analyzed these data from the Carthage field. He subdivided the wells using the date of first production as shown in Table 2 and Fig. 11.

Table 2: Time Period Categories

Group I	**1989 – 1992**
Group II	**1993 – 1995**
Group III	**1996 – 1998**
Group IV	**1999 – 2001**

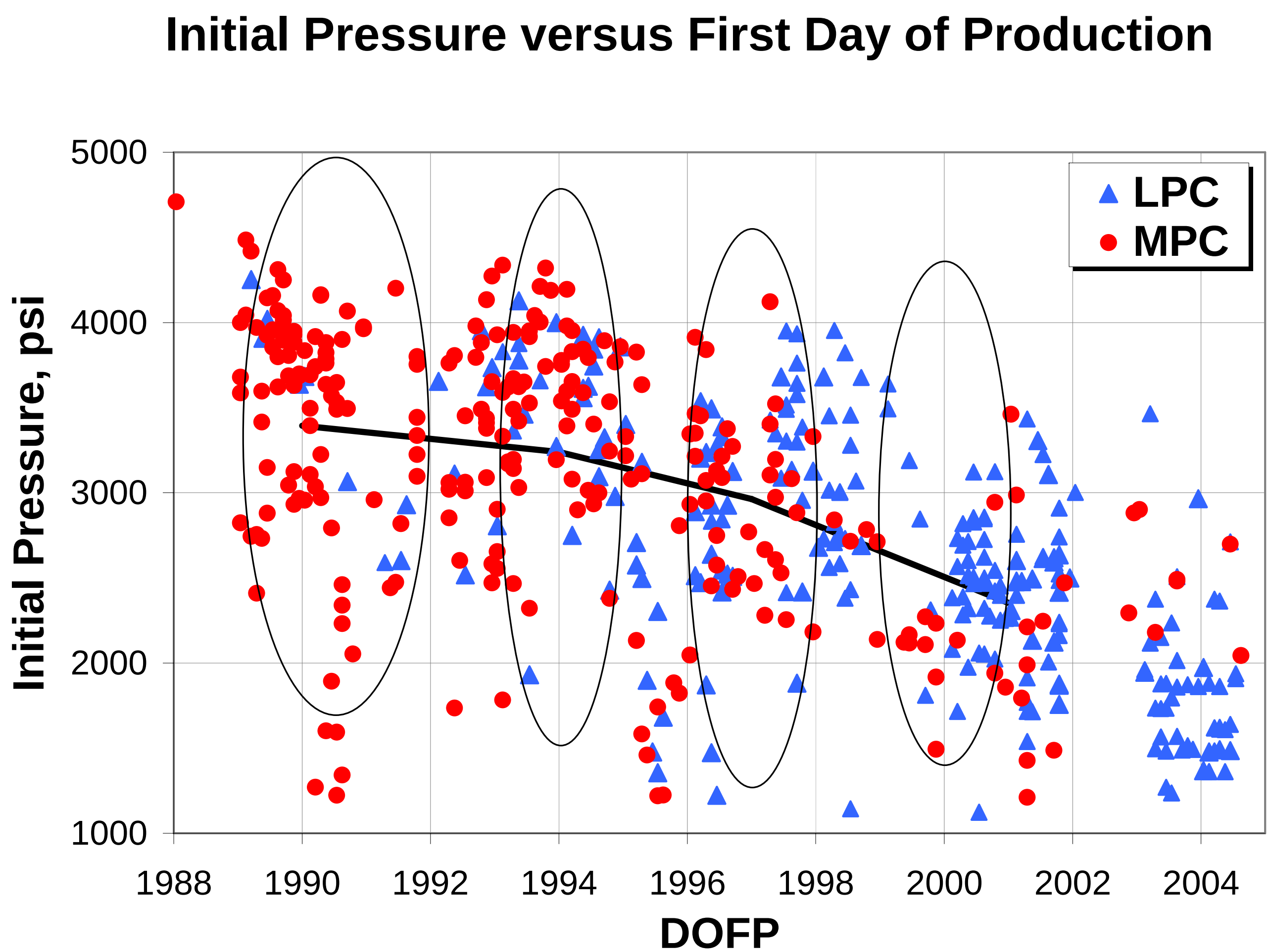

Figure 11: Well Categories by First Day of Production

In Tschirhart's analyses[3], he showed that the average well deliverability of new wells was decreasing with time because of decreasing drainage area and partial depletion (well interference) as shown in Fig. 12. He also concluded that when he analyzed the data in groups on the basis of when the wells were drilled, it was difficult to tell the difference between the production performance of the wells stimulated with medium proppant concentrations and those stimulated with low proppant concentration as shown in Fig. 13.

As such, it can be concluded, using Tschirhart's analyses[3], that the use of water fracture treatments can be justified in the Cotton Valley sands of Carthage field because the water fracture treatments are less expensive and water fracture treated wells produce about the same volume of gas during the first year as do the gel fracture treated wells. However, to continue the analyses of the Carthage field data, we decided to reanalyze the data by determining if the data should be grouped differently.

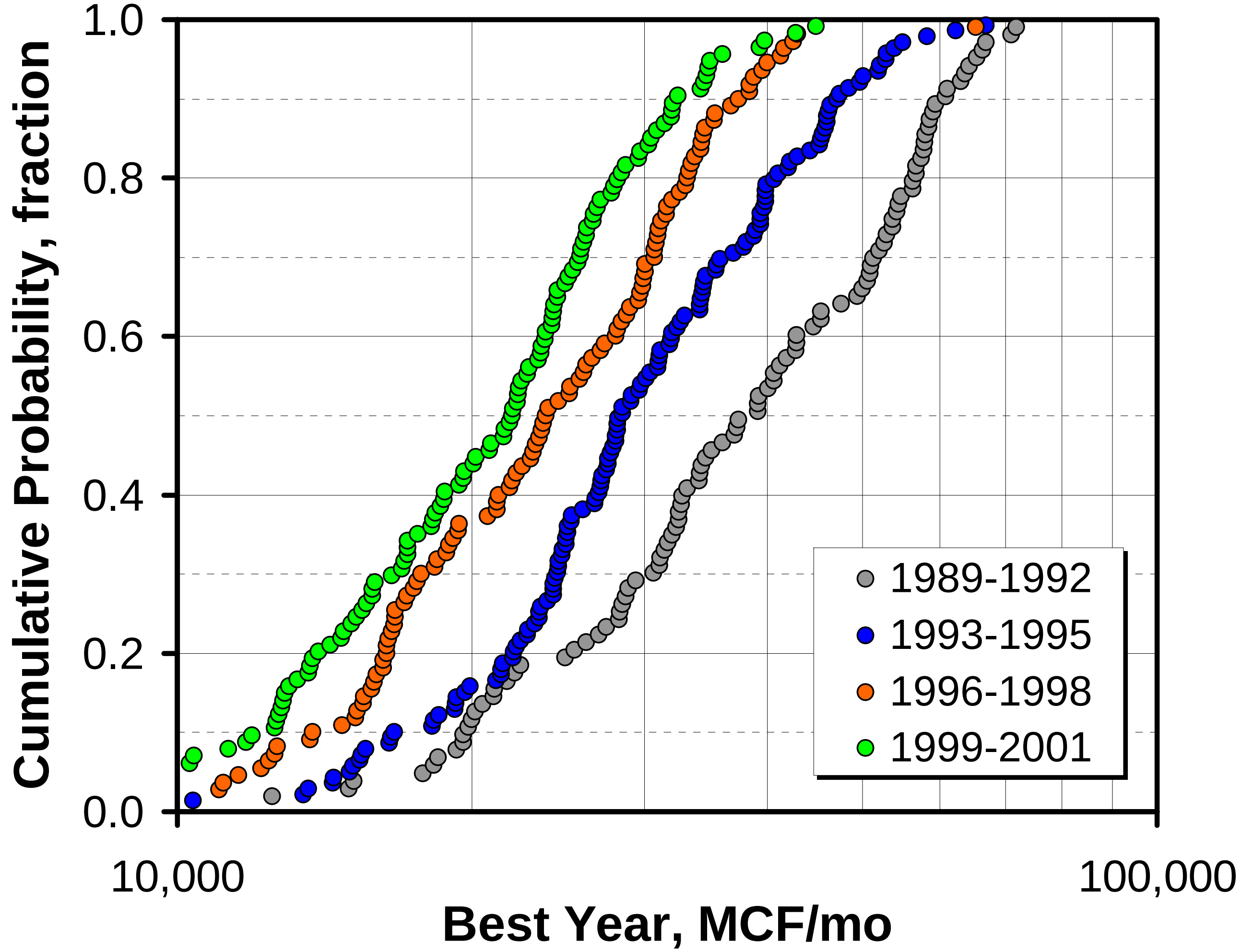

Figure 12: Well Deliverability with Time (Tschirhart[3])

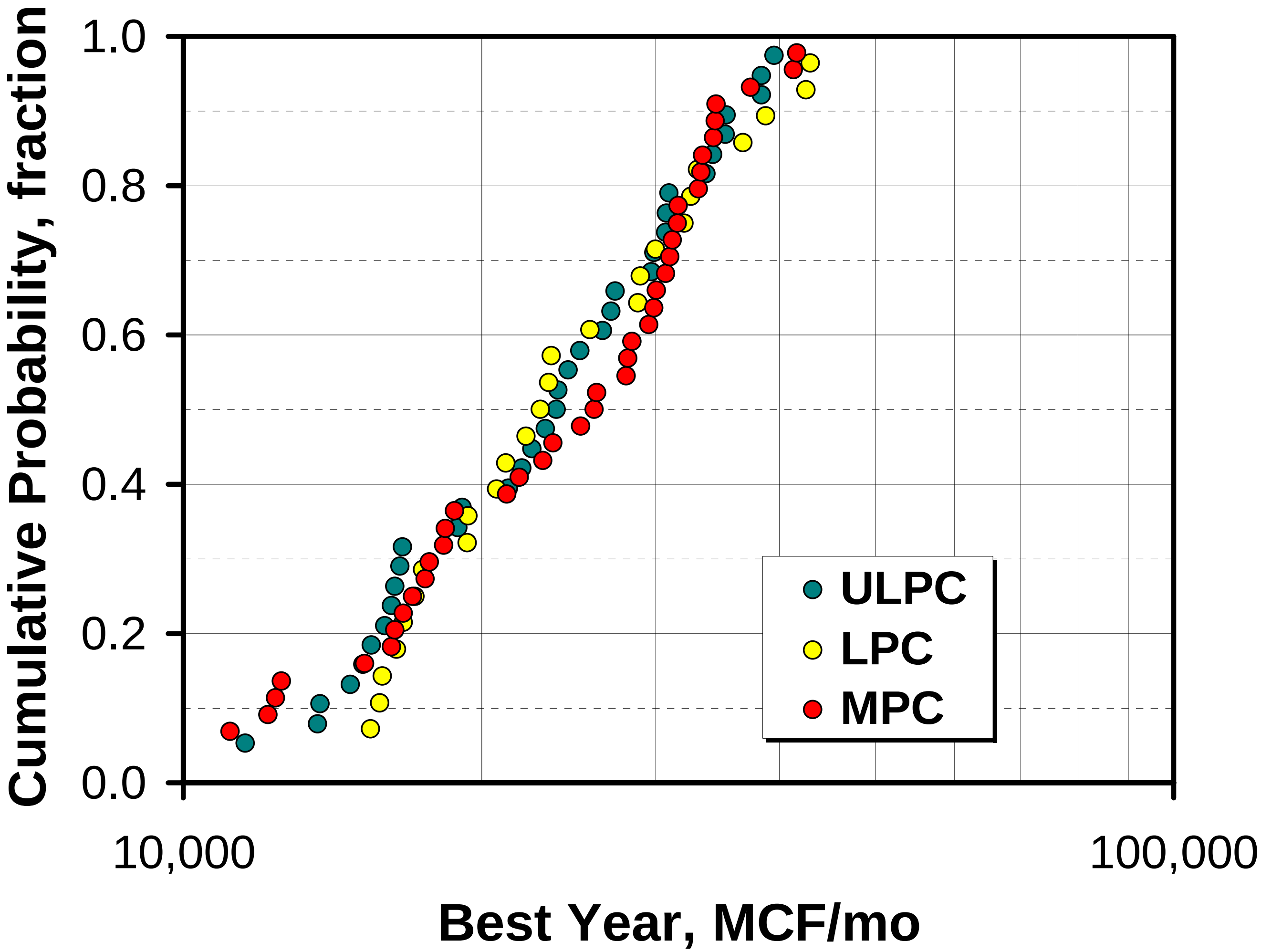

Figure 13: Cumulative Density Curves of Best Year for Wells (Tschirhart[3])

If one looks at the values of initial pressure in the data set, it is clear that some of the infill wells contact high pressure rock layers while some wells drill into highly depleted layers, assuming that data reported on the G-1 forms are accurate. To study this aspect of the problem, we subdivided the data set using the reported initial reservoir pressure. The initial pressures were calculated using data reported to Rail Road Commission (RRC). Because the Cotton Valley formation is a low permeability reservoir, we understand that the values of average reservoir pressure on the Rail Road Commission G-1 form is either equal to or, more likely, less than the actual reservoir pressure. In tight gas reservoirs, wells have to be shut-in for days or weeks to obtain accurate estimates of the average reservoir pressure. Most operators do not shut wells in for enough time to measure the true reservoir pressure, thus, the data reported to the RRC will usually be low.

As such only high pressure data were included in this study. The wells were subsequently divided into two groups as indicated in Table 3 and Fig. 14.

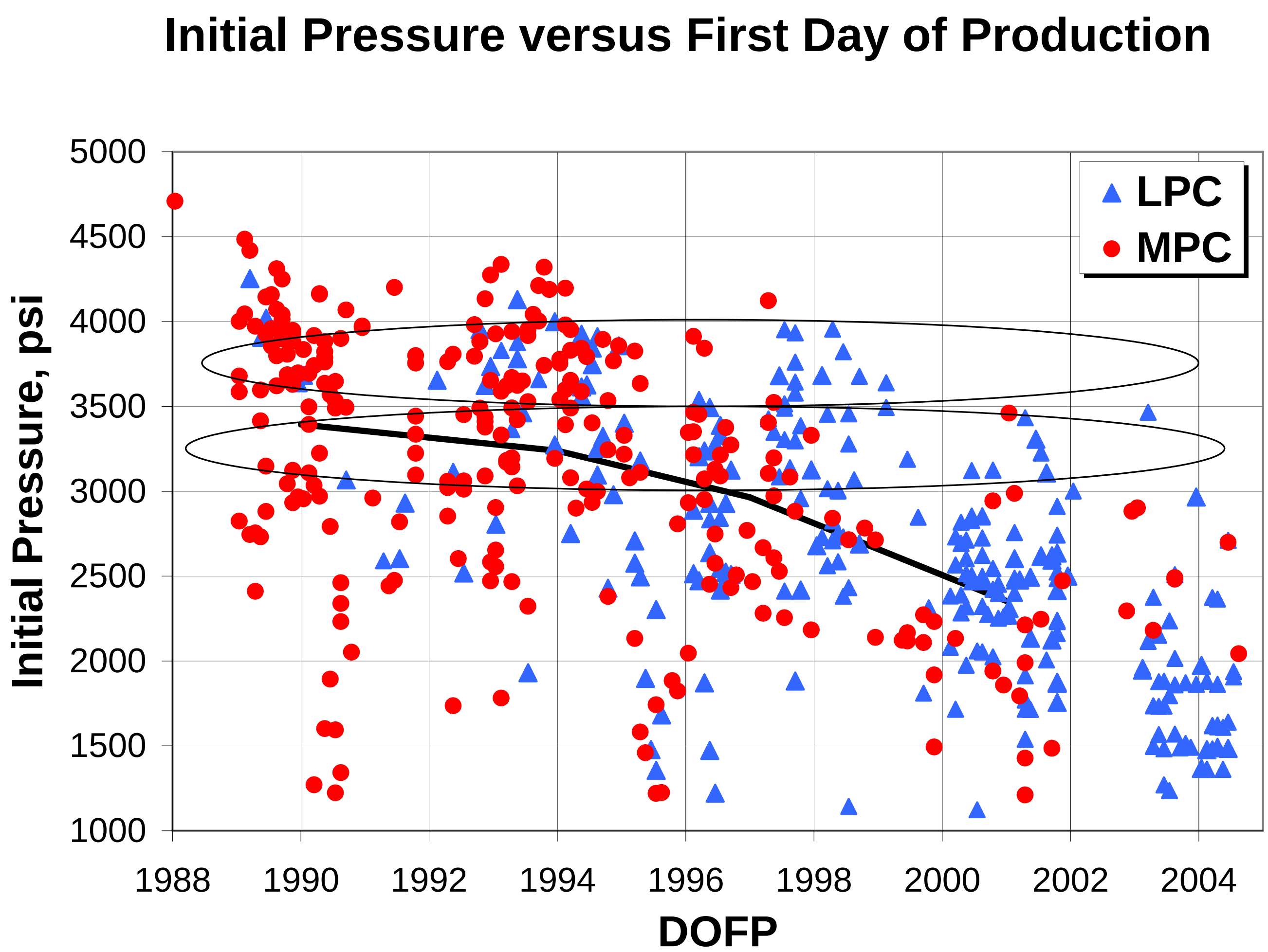

Figure 14: Well Categories by Initial Pressure

Table 3: Initial Pressure Categories

Group I	**3500-4000 psi**
Group II	**3000-3500 psi**

Production data indicators were calculated such as the Best 3 Months, Best 6 Months, and Best 12 Months of gas production during the life of the well. The Best 12 Months gas production is the best 12 consecutive months of production during the life of the well as shown in Fig. 15[26]. These values are normally seen during the first year of production.

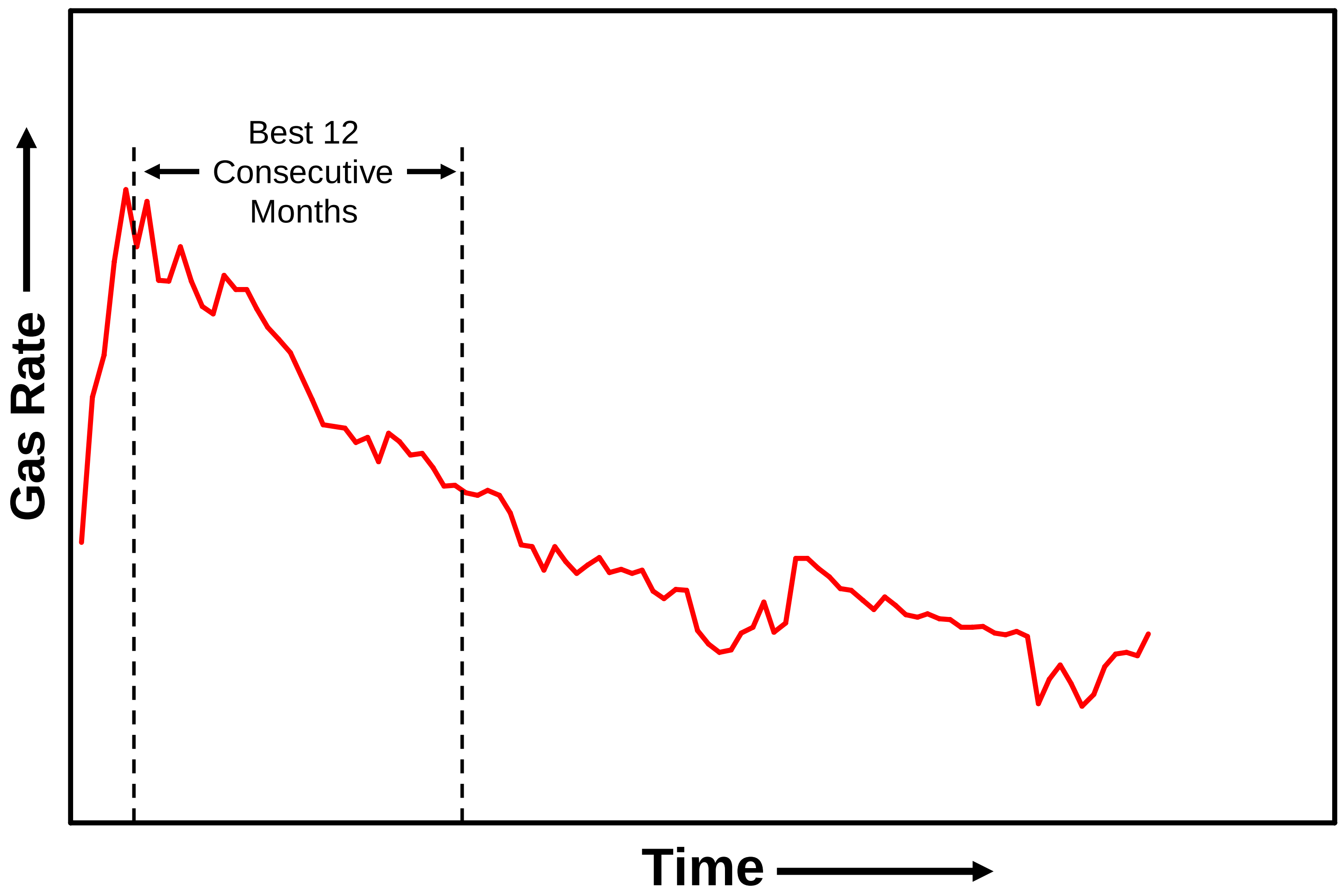

Figure 15: Definition of Best 12 Months Gas Production (Hudson *et al.* [26])

Statistical Analysis

During this study, we used statistics to see if we could determine which type of fracture treatment provides more gas production in the Cotton Valley sands in the Carthage field. We compared Best 3 Months, Best 6 Months, Best 12 Months and 3-year cumulative gas production for both groups of each type of treatment.

Comparison of Means (Hypothesis Testing):

This is a statistical method to compare two datasets. Our analysis involved choices between competing hypotheses. This method can only be applied to normally distributed datasets. We used Empirical rule to test the normality of the datasets.

The Empirical rule is based on classic bell-shape curve that is normal distribution. According to the Empirical rule, roughly 95 % data falls between two times standard deviation from mean on both sides and roughly 99 % data falls between three times standard deviation from mean on both sides.

Essential Parts of the Hypothesis Testing[27]:

1. The null hypothesis (H_0) is the specific value or model to be tested. It often represents equality or no change [In our case, the null hypothesis was gas production for both fracture treatments is same].

2. The research (alternative) hypothesis (H_1) is the conclusion to be accepted if H_0 is rejected. It often is either the conjecture the investigator would like to verify or a

statement of change. It requires strong evidence to be accepted [In our case, the research hypothesis was gas production for both fracture treatments is unequal].

3. The test statistic is a measure of the difference between the data and the null hypothesis, taking sampling error into account. It is evaluated from the data, using the following equation:

$$T = \frac{\overline{Y} - \mu}{S / \sqrt{n}}$$

4. The significance level (p-value) is the chance another random sample would have been as much in favor of the research hypothesis as the current sample is, if the null hypothesis is true. The p-value is a measure of the believability of the null hypothesis.

The choice of confidence level (α) is left to the investigator, but there are some traditional choices:

a. 90% is common for scientific research. The error rate is 1 in 10, but due to repeated and further investigation the errors will often get found out.
b. 95% is a choice used when more accuracy is required [**We used this value**].
c. 99% or similar is used when the consequences of an inaccurate conclusion are severe.

5. The rejection criterion is the condition the data must satisfy for the null hypothesis to be rejected in favor of the research hypothesis. Usually, the null hypothesis is rejected if the p-value is small enough (≤α).

Comparison Using Cumulative Density Function (cdf)[27]:

In statistics, the cumulative density function (cdf) completely describes the probability distribution of a real-valued random variable, X. For every real number x, the cdf is given by,

$$F(x) = \Pr[X \leq x] = \alpha$$

where the right-hand side represents the probability that the random variable X takes on a value less than or equal to x.

For a continuous distribution, this can be expressed mathematically as,

$$F(x) = \int_{-\infty}^{x} f(\mu)d\mu$$

For a discrete distribution, the cdf can be expressed as,

$$F(x) = \sum_{i=0}^{x} f(i)$$

In the Fig. 16, the horizontal axis is the allowable domain for the given probability function and the vertical axis is probability, the value must fall between zero and one. The value of cdf increases from zero to one as we go from left to right on the horizontal axis. When two datasets plotted on the same plot then the dataset lying on the right side of the plot has high value of mean than the dataset to its left. In our case, the dataset lying on the right is better as it yields higher gas production. Thus we can make a decision about which fracture treatment is better.

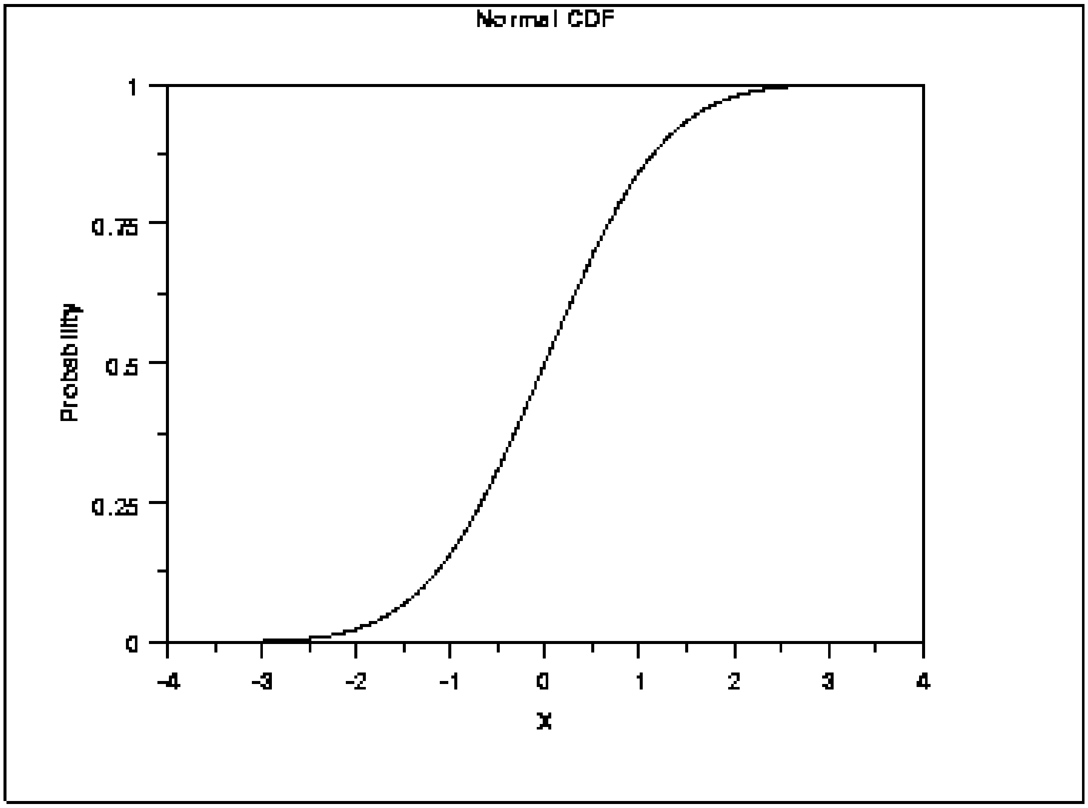

Figure 16: Normal Cumulative Distribution Function.

We graphed cumulative density functions versus Best 3 Months, Best 6 Months, Best 12 Months, and 3-year cumulative gas production for both fracture treatments for each group.

Production Data Analysis Using History Matching

Once we statistically analyzed the production data in the Carthage field, we history matched "typical" wells in various categories to determine typical values of the permeability-thickness product (kh), fracture length (L_f), and drainage area (A_d). Values for formation gas permeability, fracture half length, fracture conductivity, and drainage area can be determined for wells by history matching production data using the analytical simulator "Promat[28]". Promat is a single-phase, single-layer production data analysis tool which uses a gradient based optimization technique.

Normally, it is difficult to obtain unique solutions for gas permeability, fracture conductivity, drainage area, and fracture half length simultaneously when analyzing only production data. Gas permeability in the Cotton Valley sands can range anywhere from 0.005 to 0.05 md; within this range, an incorrect estimation of permeability can have a significant effect on the estimate of the fracture parameters. So making comparison of these history matches for each sub-group was difficult unless other data can be used to estimate formation permeability.

Lee and Holditch[29] encountered similar problems and found that obtaining unique solutions requires a prior knowledge of gas permeability obtained from pre-stimulation well tests or post-fracture buildup tests. Poe *et al.*[14] suggested that when these tests are unavailable, it has been found that daily rate-pressure data can be sometimes used to address non-unique solutions. These test and daily rate-pressure data was unavailable for this study.

Tschirhart[3] demonstrated an excellent example of non-uniqueness while history matching production data for a well completed in the Carthage field. He made two runs for same well with different initial guesses for reservoir parameters and obtained good matches with actual long term production data for both runs. But the values obtained for fracture length (L_f) and fracture conductivity (wk_f) were totally different as shown in Fig. 17.

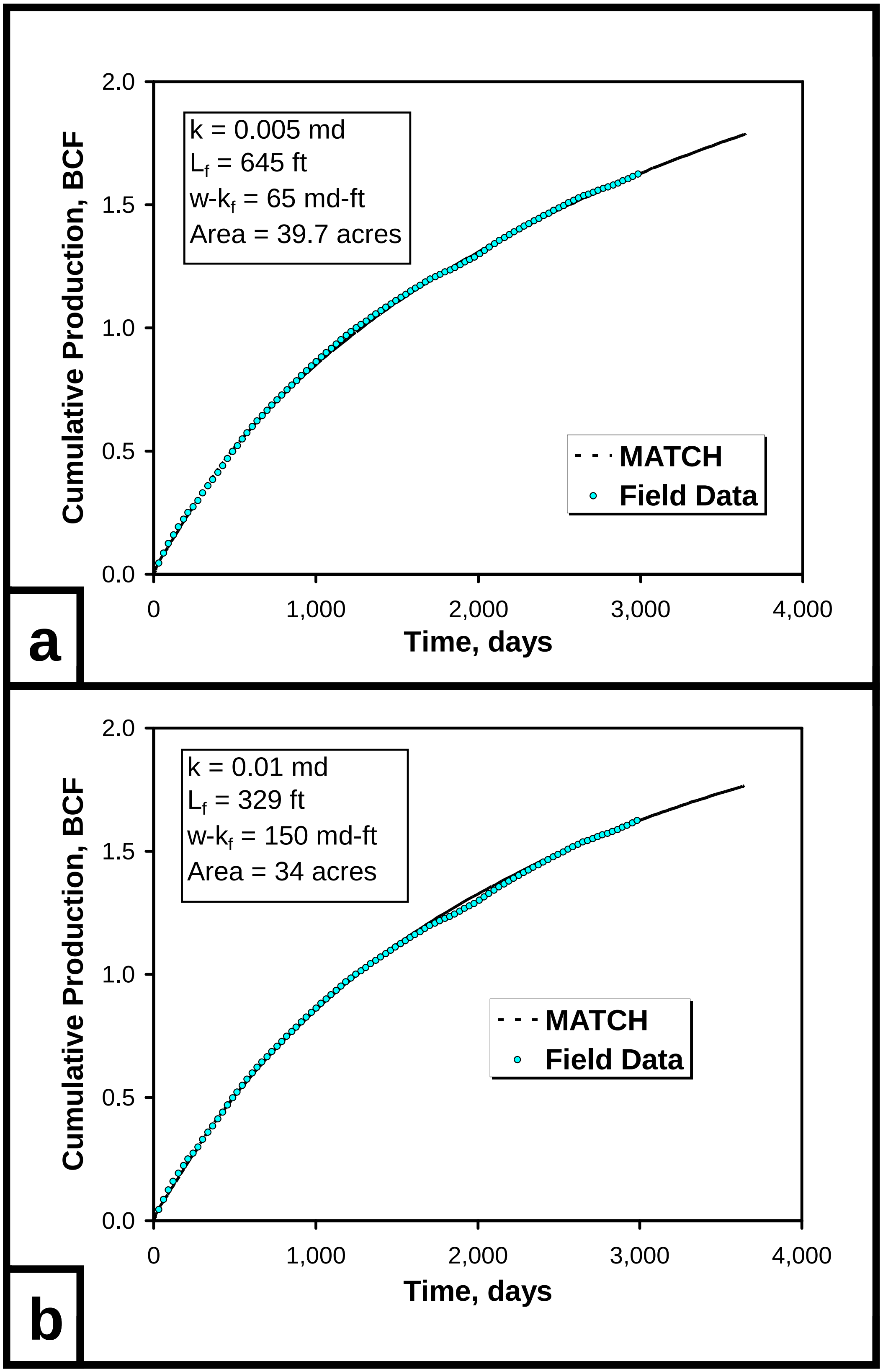

Figure 17: Non-uniqueness Involved in History Matching (Tschirhart[3])

As an alternative to test ways to improve the uniqueness of the match, we fixed several fracture parameters to a constant value such as the fracture conductivity (to a typical value of 100 md-ft) and choked skin (to a value of 0) to history match the wells for different values of permeability (from 0.005 to 0.05). We had tops and bottoms of the perforated intervals, so we assumed net pay to be 40 % of gross pay and used these values of net pay.

We history matched 63 wells within various categories and determined the values for effective fracture half length and effective drainage area. We then performed similar statistical analysis, mentioned in section 3.2, hypothesis testing and cumulative density curve on estimated parameters for each sub-category to evaluate the fracture treatments. The values of kh were used to certain our data-sets are comparable.

Table 4 shows input data entered in Promat for a typical well besides the pressure history and production data. Table 5 shows output parameters obtained from Promat after history matching the production data.

Table 4: Input Data for History Matching a Typical Well

Parameter	**Value**	**Units**
Formation temperature	230	0F
Initial reservoir pressure	3750	psi
Gross Pay	810	ft
Net pay (40 % of gross pay)	325	ft
Wellbore radius	0.25	ft
Porosity	10	percent
Water saturation	30	percent
Water compressibility	3.6 E-6	psi-1
Formation compressibility	4 E-6	psi-1
Reservoir gas gravity	0.7	-
Permeability	0.005	md
Fracture half-length	100	ft
Fracture conductivity	100	md-ft
Area	40	acres

Table 5: Output after History Matching a Typical Well

Parameter	**Value**	**Units**
Permeability	0.005	md
Fracture half-length	200	ft
Fracture conductivity	100	md-ft
Area	13.5	acres

Fig. 18 shows a plot of average gas production rate and cumulative gas production for the same well where red circles represent the field data while solid line indicates matched fit. Fig. 19 shows a plot of cumulative gas production and time and Fig. 20 shows a plot of average production rate and time.

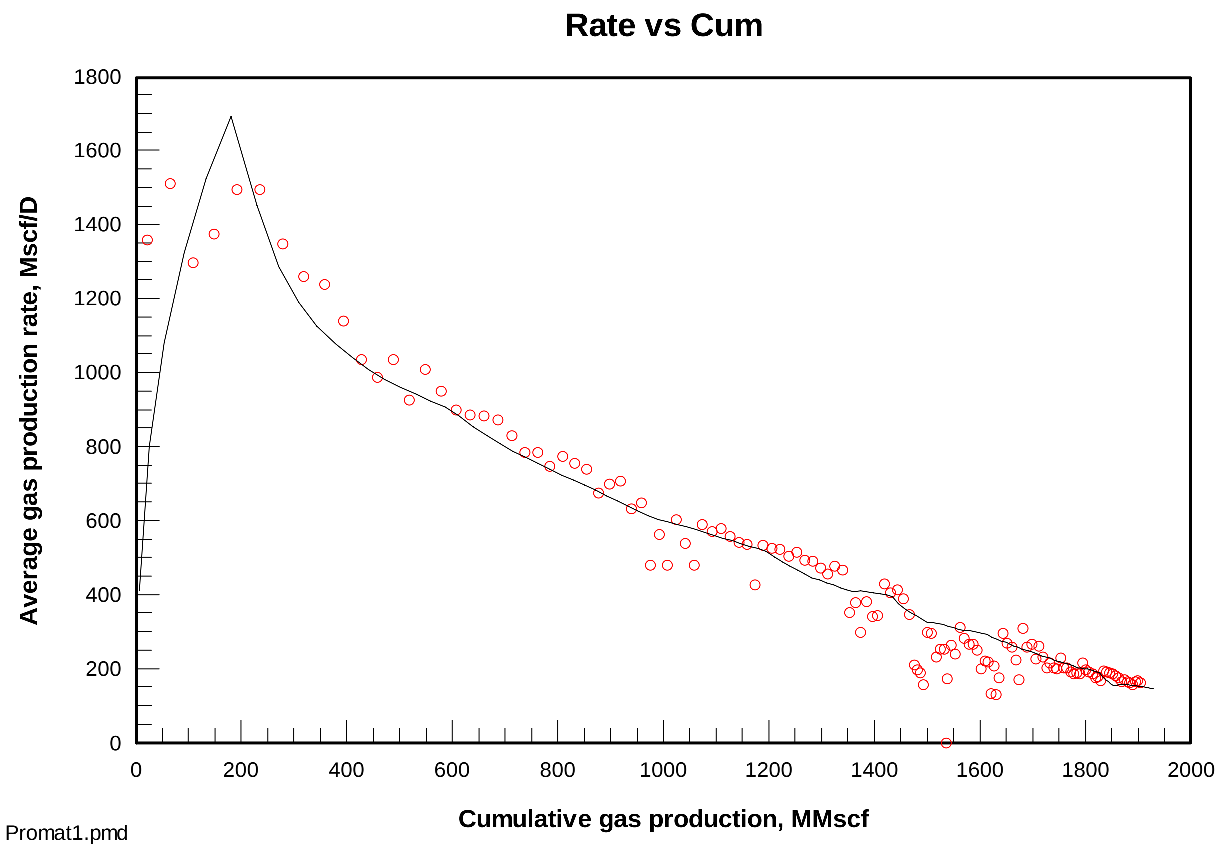

Figure 18: Average Gas Production Rate and Cumulative Gas Production

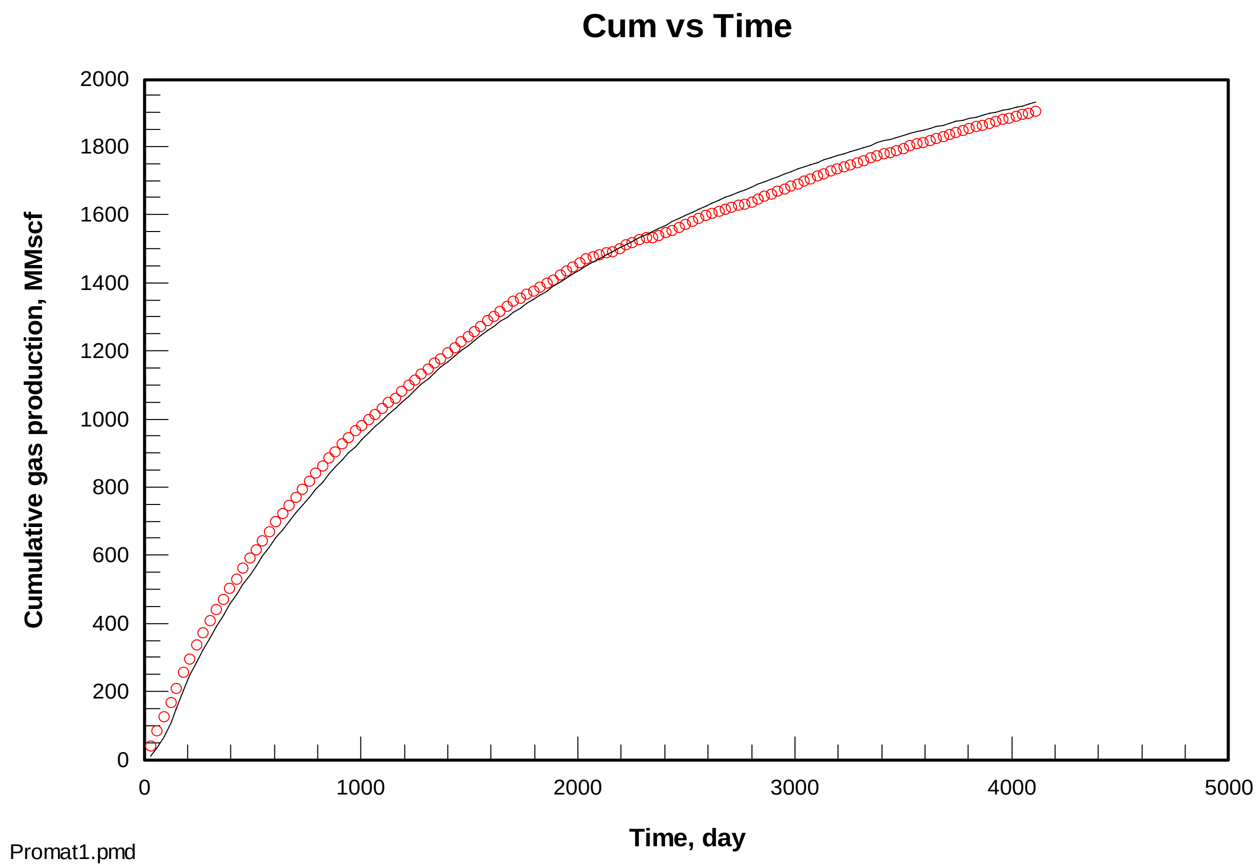

Figure 19: Cumulative Gas Production and Time

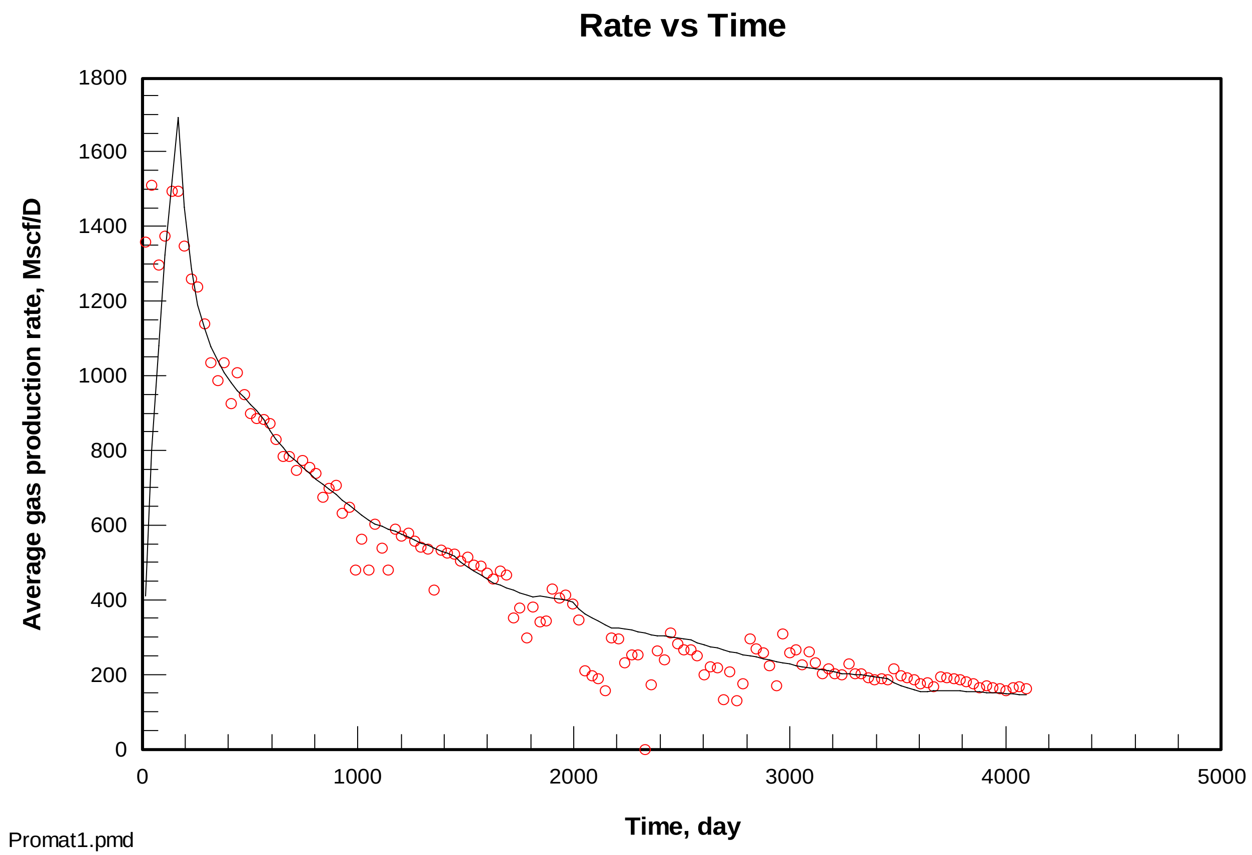

Figure 20: Average Gas Production Rate and Time

Fracture Propagation Modeling

We used a fully 3D fracture propagation model, StimPlan[30], to review fracture treatments for different scenarios to determine crucial factors associated with the success/failure of a particular type of fluid used in a fracture treatment. The scenarios took into account various parameters such as type and amount of fracturing fluids and additives, type and size of proppants, net pay thickness, strength of lower barrier, Young's modulus of the layer below the pay interval, permeability of the formation, and effective length of the fracture.

We generated hundreds of computer runs to learn and then describe typical situations where water facture treatments work and where they do not work. We developed a description of a layered reservoir similar to Cotton Valley sands in the East Texas for this work. We used this model to simulate hydraulic fracture propagation for water fracture treatments, gel fracture treatments, and hybrid fracture treatments. It was sometimes difficult to develop datasets for the fully 3D model that would give us conditions where water fracture treatments worked well in a formation like the Cotton Valley in East Texas.

Table 6 presents the data for a water fracture fluid treatment, while Table 7 presents the data for gel fracture fluid treatment. Table 8 shows proppant description for Brady 20-40 sand, and Table 9 shows the friction data used.

Table 6: Water Fracture Fluid Description

Choose Fluid: Water Fracture Fluid

Specific Gravity (Water = 1.0)	Foam Quality Nitrogen%	Foam Quality C02%	Fall Correction Factor (1.0 = Stokes Law)	Costs $/gal	Fluid Pipe Friction Factor
1.0000	0	0	0.50	0.50	1.0

	Non-Newtonian N'	K'	Viscosity (cp) (@170.0 1/sec)
@ Wellbore Temperature	0.71	0.001430	15.7
@ Formation Temperature	1.00	0.000008	0.4
1.00 Hours	1.00	0.000009	0.4
2.00 Hours	1.00	0.000008	0.4
4.00 Hours	1.00	0.000008	0.4
8.00 Hours	1.00	0.000008	0.4

Table 7: Gel Fracture Fluid Description

Choose Fluid: Gel Fracture Fluid

Specific Gravity (Water = 1.0)	Foam Quality Nitrogen%	Foam Quality C02%	Fall Correction Factor (1.0 = Stokes Law)	Costs $/gal	Fluid Pipe Friction Factor
1.0400	0	0	0.50	0.00	1.0

	Non-Newtonian N'	K'	Viscosity (cp) (@170.0 1/sec)
@ Wellbore Temperature	0.81	0.011962	220.0
@ Formation Temperature	0.83	0.010794	220.0
1.00 Hours	0.83	0.007801	159.0
2.00 Hours	0.81	0.007993	147.0
3.00 Hours	0.78	0.007928	125.0
4.00 Hours	0.76	0.006888	98.0

Table 8: Proppant Description

Choose Proppant: Brady Sand 20-40

For All Proppants Prop Lost to Embedment (lb/ft^2)	Specific Gravity (Sand = 2.65)	Damage Factor (1.0 = No Damage)	Costs $/lb
0.20	2.65	0.70	0.10

(All Input at 2 lb/ft^2)

Confining Stress (psi)	Conductivity (md-ft)	Propped Width (in)	Beta (1/ft)
0 psi:	6800.0	0.2502	12065.900
2000 psi:	5550.0	0.2502	13355.700
4000 psi:	3000.0	0.2367	27824.599
8000 psi:	480.0	0.2156	167676.00
16000 psi:	20.0	0.2052	1471920.0

Table 9: Fiction Data Entered in the Simulator

Enter 1 to 5 Rate/Pressure Data Pairs

Rate (BPM)	dP/dL (psi/100ft)
10.5	1.0
20.0	2.2
30.0	4.0
40.0	5.5
50.0	8.0

Slurry Friction Factor 0.50

Overall Fluid Friction Factor 1.0000

Wellbore Path
Enter 2 to 9 MD/TVD Pairs

MD (ft)	TVD (ft)	Pipe ID (in)	Gauge Locate
0.0	0.0	0.000	◉
5000.0	5000.0	5.500	○
7000.0	7000.0	5.500	○
8000.0	8000.0	5.500	○
9000.0	9000.0	5.500	○
10000.0	10000.0	5.500	○
			○
			○

Wellbore Volume (M-Gal) 12.34

"Perforation" Friction

Number of Active Perfs	Perf Diam (in)
100	0.35

☐ Use Empirical Friction

Friction dP=aQ^b

a	b
0.0234	2.0000

Downhole Friction (psi)

at (BPM)	dP (psi)
10.00	2.3400

Interview Experts

We built a questionnaire to interview experts in the industry who design and pump fracture treatments in tight gas reservoirs (refer to appendix A). The questionnaire was used to investigate the factors they consider while selecting a fracture fluid, especially top five factors in order of importance. The questionnaire was also used to investigate typical situations to employ limited-entry fracturing, single stage fracturing, and multi-stage fracturing. The questionnaire asked how experts decide upon the amount of pre-pad to be pumped, amount of pad to be pumped, amount of total fracturing fluid to be pumped, optimum viscosity of the fracturing fluid, injection rate, type of proppant, and size of the proppant.

Eleven experts in the industry sent in the questionnaire and described the parameters they consider before designing any particular fracture treatment. We used the results and information in the literature to develop an expert advisor for selecting fracture fluids for tight gas reservoirs. We also summarized their opinions regarding use of limited-entry, single stage, and multi-stage fracturing.

Fracture Fluid Advisor

The final portion of this work was to pull all of the analysis together to publish a user's guide to offer advice on when water fracture treatments should be pumped and when they should not be. As a part of the work, when water fracture treatments should not be used, we offered advice on the proper use of gel fracture treatments or hybrid fracture treatments. We also developed an expert advisor for selecting an appropriate fracturing fluid. The advisor focuses more on the medium temperature, medium pressure reservoirs like Cotton Valley sands in the East Texas.

CHAPTER IV

RESULTS AND DISCUSSION

Field Data Analysis

Statistical Analysis

Comparison of Means for Field Data

Data for hypothesis testing for all the wells in group I and group II based upon 3-year cumulative gas production is shown in Table 10.

Table 10: Data for Hypothesis Testing Based Upon 3-Year Cumulative Gas

3-Year Cumulative Gas Production	Group I		Group II	
	MPC	LPC	MPC	LPC
Mean, Mcf	995,200	808,615	867,002	596,357
Standard Deviation	411,830	368,870	291,653	225,655
Data Points	85	41	65	44

Testing normality: The Empirical rule was used to test normality of datasets shown in Table 11.

Table 11: Data for Testing Normality for 3-Year Cumulative Gas

3-Year Cumulative Gas Production	Group I		Group II	
	MPC	LPC	MPC	LPC
Mean ± 2 Std. Dev.	98 %	95 %	95 %	95 %
Mean ± 3 Std. Dev.	99 %	100 %	100 %	100 %

All datasets qualified using the Empirical rule indicated they were normally distributed.

Null hypothesis: Means are equal for both types of fracture treatments. H_0: $\mu_1 = \mu_2$

Research hypothesis: Means are unequal for both types of fracture treatments. H_1: $\mu_1 \neq \mu_2$

Table 12: Results of Hypothesis Testing Based Upon 3-Year Cumulative Gas

Parameter	**Values**	
	Group I	**Group II**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.01	0.00

The p-value was less than rejection criterion, α, so we can reject the null hypothesis. This indicates 3 year cumulative production was unequal for MPC and LPC with 95 % significance level as shown in Table 12. MPC does much better than LPC for both group I and group II wells as shown in Fig. 21 when compared on the basis of 3-year cumulative gas production.

We also performed similar hypothesis testing based upon Best 3 Months, Best 6 Months, and Best 12 Months gas production (refer to appendix B).

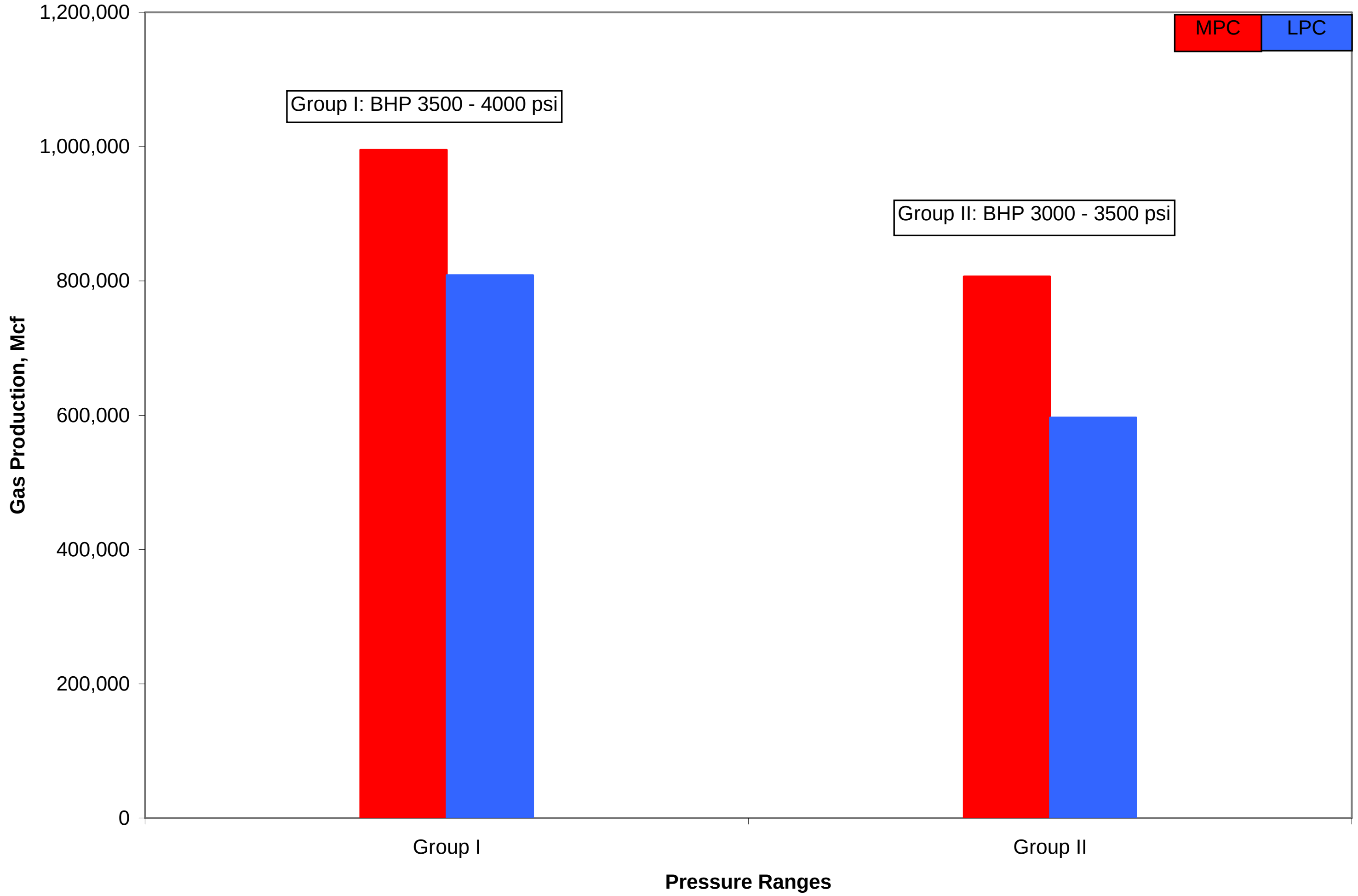

Figure 21: Comparison of Average 3-Year Cumulative Gas Production for Wells in the Carthage Field

Comparison of Cumulative Frequency Curves

In Fig. 22, the cumulative density function versus 3-year cumulative gas production is plotted for both group I and group II for all wells. On average, the wells in group I produces more gas than wells in group II. This indicates production performance of these wells is directly dependent in part on initial reservoir pressure of the wells.

Similarly, we plotted cumulative density function versus 3-year cumulative gas production for both fracture treatments for all wells as shown in Fig. 23. On average, the MPC wells produce more gas than LPC wells which demonstrates that production performance of these wells is also depends on amount of proppant and proppant concentration pumped in the wells.

In Fig. 22, on average, the wells in group I produces more gas than wells in group II. This indicates production performance of these wells is directly dependent on initial reservoir pressure of the wells and high pressure wells are better than low pressure wells. Similarly, in Fig. 23, on average, the MPC wells produce more gas than LPC wells which demonstrates that production performance of these wells is also depends on amount of proppant and proppant concentration pumped in the wells.

Fig. 24 is a plot of cumulative density function for 3-year cumulative gas production for both pressure groups and both fracture treatments. We also plotted similar cumulative density curves for Best 3 Months, Best 6 Months, and Best 12 Months gas production (refer to appendix B).

Fig. 24 is a plot of cumulative density function for 3-year cumulative gas production for both pressure groups and both fracture treatments. Group I MPC wells are on the right side of the Group I LPC wells and Group II MPC wells are on the right side of the Group II LPC wells. This indicates MPC wells are better as they yield higher gas production. Group II MPC wells and Group I LPC wells cumulative density curves are lying on top of each other which indicate lower pressure MPC wells are as good as higher pressure LPC wells.

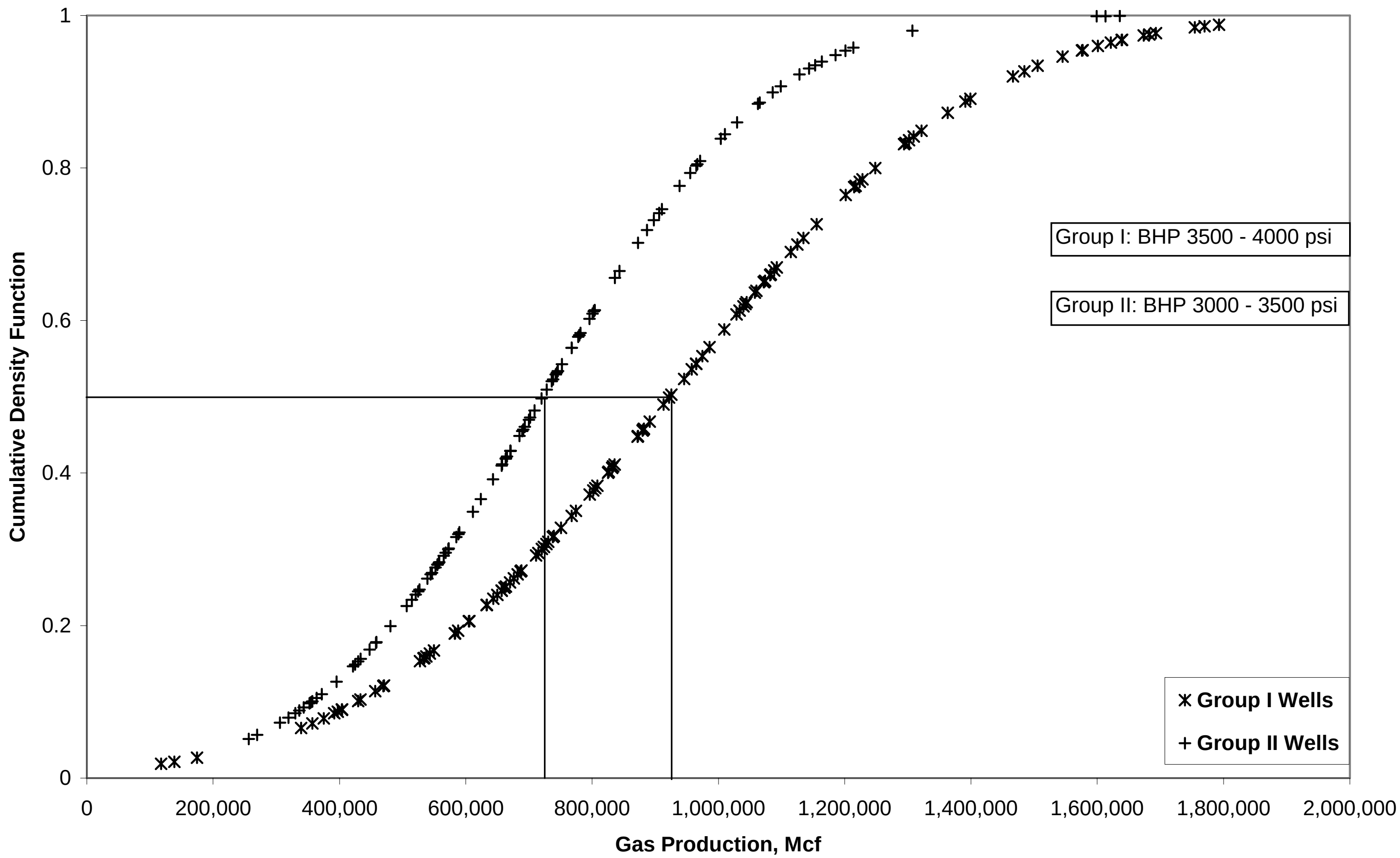

Figure 22: Cumulative Frequency Distribution for 3-Year Cumulative Gas Production Compared Based on Initial Pressure

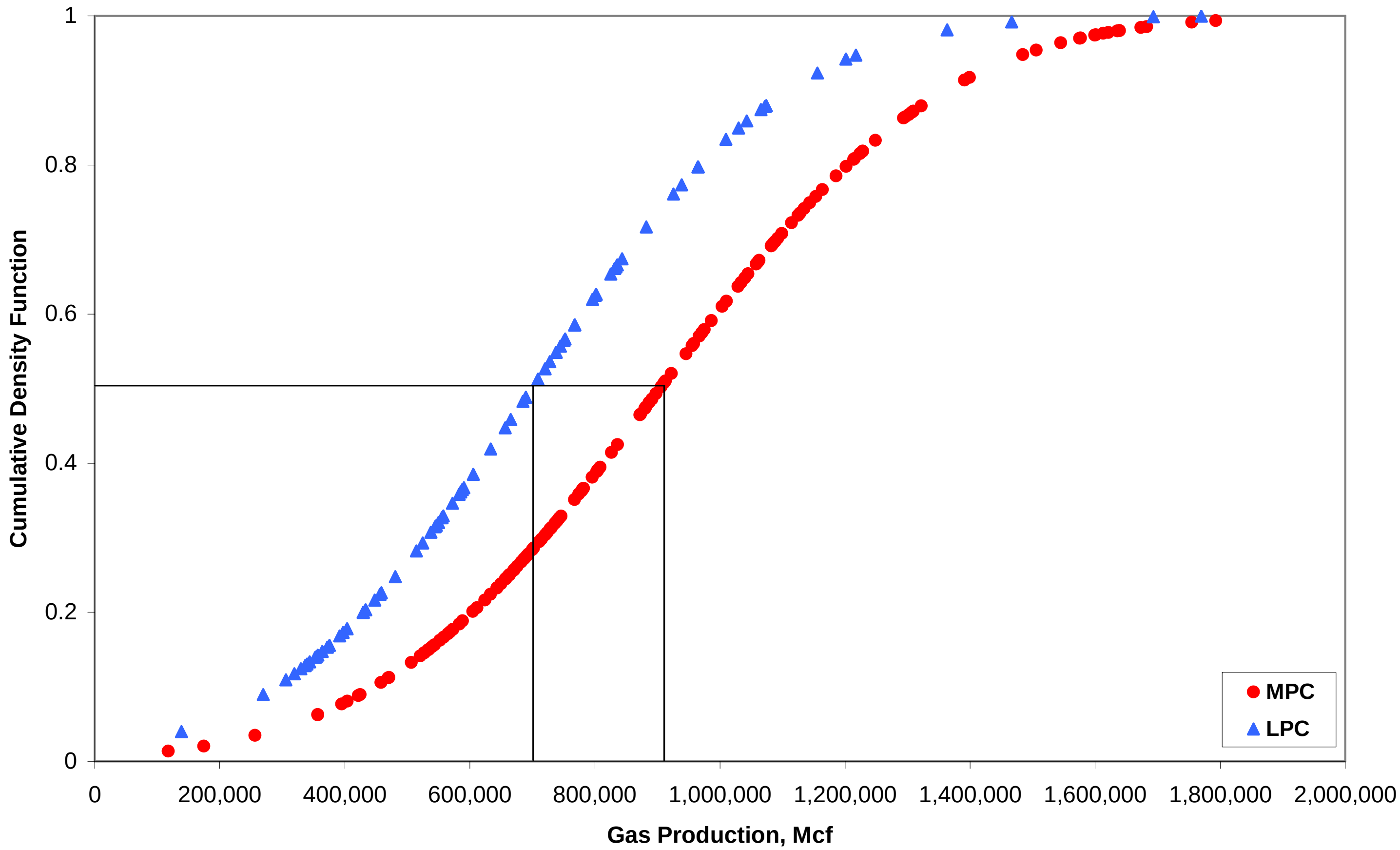

Figure 23: Cumulative Frequency Distribution for 3-Year Cumulative Gas Production Compared Based on Proppant Concentration

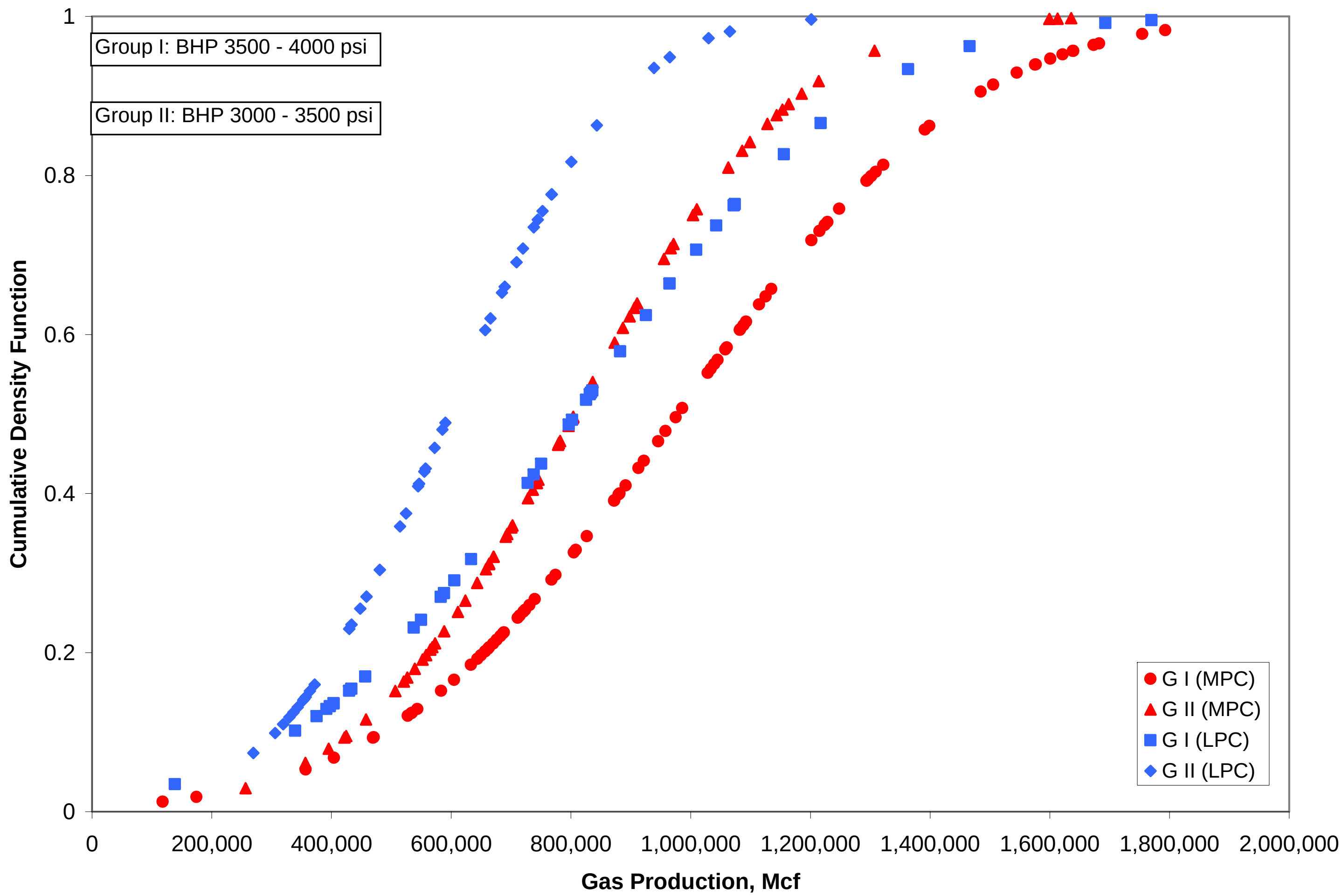

Figure 24: Cumulative Frequency Distribution for 3-Year Cumulative Gas Production for Both Groups and Both Treatments (Carthage)

Production Data Analysis: History Matching

Table 13 shows the output parameters obtained from Promat after history matching the production data for Group I MPC wells. Similarly, Table 14 shows the output parameters for Group I LPC wells. Table 15 shows the output parameters for Group II MPC wells. Similarly, Table 16 shows the output parameters for Group II LPC wells. (The results are in colored columns)

Table 13: Output Data for Group I MPC wells (Group I: BHP 3500-4000 psi)

Well No.	Pi (psi)	k (md)	h (ft)	kh (md-ft)	Lf (ft)	Ad (acres)
1	3557	0.005	180	0.9	198	40
2	3569	0.005	340	1.7	32.37	6
3	3597	0.005	340	1.7	114	12
4	3630	0.005	333	1.665	380.6	17
5	3647	0.005	337	1.685	366.7	25
6	3686	0.005	320	1.6	565.3	26
7	3687	0.005	332	1.66	460.9	28
8	3697	0.005	302	1.51	460.8	26
9	3741	0.005	325	1.625	200.7	13.5
10	3753	0.005	335	1.675	108.1	9.5
11	3777	0.005	335	1.675	405.4	21
12	3786	0.005	242	1.21	112.4	12
13	3793	0.005	137	0.685	474.3	28
14	3798	0.005	360	1.8	184.9	15.5
15	3806	0.005	349	1.745	77.77	8.3
16	3842	0.005	322	1.61	175.8	10
17	3855	0.005	339	1.695	56.36	6
18	3883	0.005	328	1.64	72.29	11
19	3894	0.005	336	1.68	365.2	26
20	3896	0.005	353	1.765	276.6	17.2
21	3910	0.005	271	1.355	239	22
22	3924	0.005	301	1.505	326	19
23	3927	0.005	172	0.86	626.7	40
24	3951	0.005	107	0.535	323.1	32
25	3954	0.005	120	0.6	703.8	58
26	3957	0.005	311	1.555	261.1	18.5
27	3960	0.005	340	1.7	390	21
28	3971	0.005	190	0.95	740.6	47
29	3999	0.005	370	1.85	399.5	19

Table 14: Output Data for Group I LPC wells (Group I: BHP 3500-4000 psi)

Well No.	Pi (psi)	k (md)	h (ft)	kh (md-ft)	Lf (ft)	Ad (acres)
1	3515	0.005	329	1.645	212.3	12.5
2	3519	0.005	329	1.645	155.1	14
3	3547	0.005	312	1.56	157.8	9
4	3643	0.005	333	1.665	48.35	5
5	3691	0.005	322	1.61	73.8	8
6	3718	0.005	316	1.58	217	14.7
7	3761	0.005	333	1.665	22.32	5
8	3803	0.005	319	1.595	128.6	7.1
9	3822	0.005	325	1.625	206	11
10	3901	0.005	370	1.85	270.2	16.5
11	3922	0.005	327	1.635	178.9	13.2
12	3933	0.005	314	1.57	151.1	9.5

Table 15: Output Data for Group II MPC wells (Group II: BHP 3000-3500 psi)

Well No.	Pi (psi)	k (md)	h (ft)	kh (md-ft)	Lf (ft)	Ad (acres)
1	3107	0.005	247	1.235	281.3	22
2	3111	0.005	321	1.605	273.1	14
3	3123	0.005	342	1.71	561	28.5
4	3196	0.005	312	1.56	146.3	13
5	3217	0.005	301	1.505	195.1	23.1
6	3329	0.005	329	1.645	148.7	12
7	3352	0.005	322	1.61	332.7	19.1
8	3392	0.005	336	1.68	126.1	9.5
9	3415	0.005	234	1.17	176.9	12.5
10	3489	0.005	338	1.69	157.2	12

Table 16: Output Data for Group II LPC wells (Group II: BHP 3000-3500 psi)

Well No.	Pi (psi)	k (md)	h (ft)	kh (md-ft)	Lf (ft)	Ad (acres)
1	3001	0.005	328	1.64	47.39	5.5
2	3006	0.005	333	1.665	126.2	10.5
3	3085	0.005	339	1.695	108.5	12
4	3122	0.005	260	1.3	158.6	10
5	3124	0.005	205	1.025	257.9	9
6	3138	0.005	154	0.77	147	8
7	3279	0.005	322	1.61	163.2	10
8	3297	0.005	212	1.06	89.28	9.5
9	3304	0.005	157	0.785	146.1	15
10	3452	0.005	293	1.465	42.03	5.5
11	3456	0.005	343	1.715	187.3	12
12	3489	0.005	337	1.685	303	18

<u>Hypothesis Testing</u>

Data for hypothesis testing for all the wells in group I based on estimated effective fracture half-length is shown in Table 17.

Table 17: Data for Hypothesis Testing Based Upon Fracture Half-length

Effective Fracture Half-length	**Group I**		**Group II**	
	MPC	**LPC**	**MPC**	**LPC**
Mean, ft	314	152	240	148
Standard Deviation	194	90	122	88
Data Points	29	12	10	12

Testing normality: The Empirical rule was used to test normality of datasets shown in Table 18.

Table 18: Data for Testing Normality for Fracture Half-length

Effective Fracture Half-length	**Group I**		**Group II**	
	MPC	**LPC**	**MPC**	**LPC**
Mean ± 2 Std. Dev.	95%	100 %	96 %	95 %
Mean ± 3 Std. Dev.	100 %	100 %	100 %	100 %

Both datasets qualified the Empirical rule that indicated they were normally distributed.

Null hypothesis: Means are equal for both types of fracture treatments. H_0: $\mu_1 = \mu_2$

Research hypothesis: Means are unequal for both types of fracture treatments. H_1: $\mu_1 \neq \mu_2$

Table 19: Results of Hypothesis Testing Based Upon Fracture Half-length

Parameter	**Values**	
	Group I	**Group II**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.003	0.03

The p-value was less than rejection criterion, α, so we can reject the null hypothesis. This indicates estimated effective fracture half-length was unequal for MPC and LPC with 95 % significance level as shown in Table 19. MPC does much better than LPC for both group I and group II wells as shown in Fig. 25 when compared on the basis of estimated effective fracture half-length. We also performed similar hypothesis testing based upon effective drainage area (refer to appendix C).

Fig. 26 is a plot of cumulative density function for estimated effective fracture half-length for both pressure groups and both fracture treatments. We also plotted similar cumulative frequency curve for effective drainage area (refer to appendix C). The Group I MPC wells are on the right side of the Group I LPC wells and The Group II MPC wells are on the right side of the Group II LPC wells. This indicates MPC wells are better as they have longer effective fractures.

As we mentioned, in Fig. 24 Group II MPC wells and Group I LPC wells 3-year cumulative gas production cumulative density curves are lying on top of each other while in Fig. 26 Group II MPC wells are to the right side of Group I LPC wells. This indicates that Group II MPC wells have longer estimated fracture half-lengths than Group I LPC wells but produce almost same amount of gas. This may be because of insufficient fracture cleanup at lower pressure.

In Fig. 26, Group I MPC wells are to the right side of Group II MPC wells which indicates that estimated fracture half-length is a function of pressure for MPC fracture treatments. While Group I LPC wells and Group II LPC wells cumulative density curves are lying on top of each other which indicate that estimated fracture half-length is not a function of pressure for LPC fracture treatments.

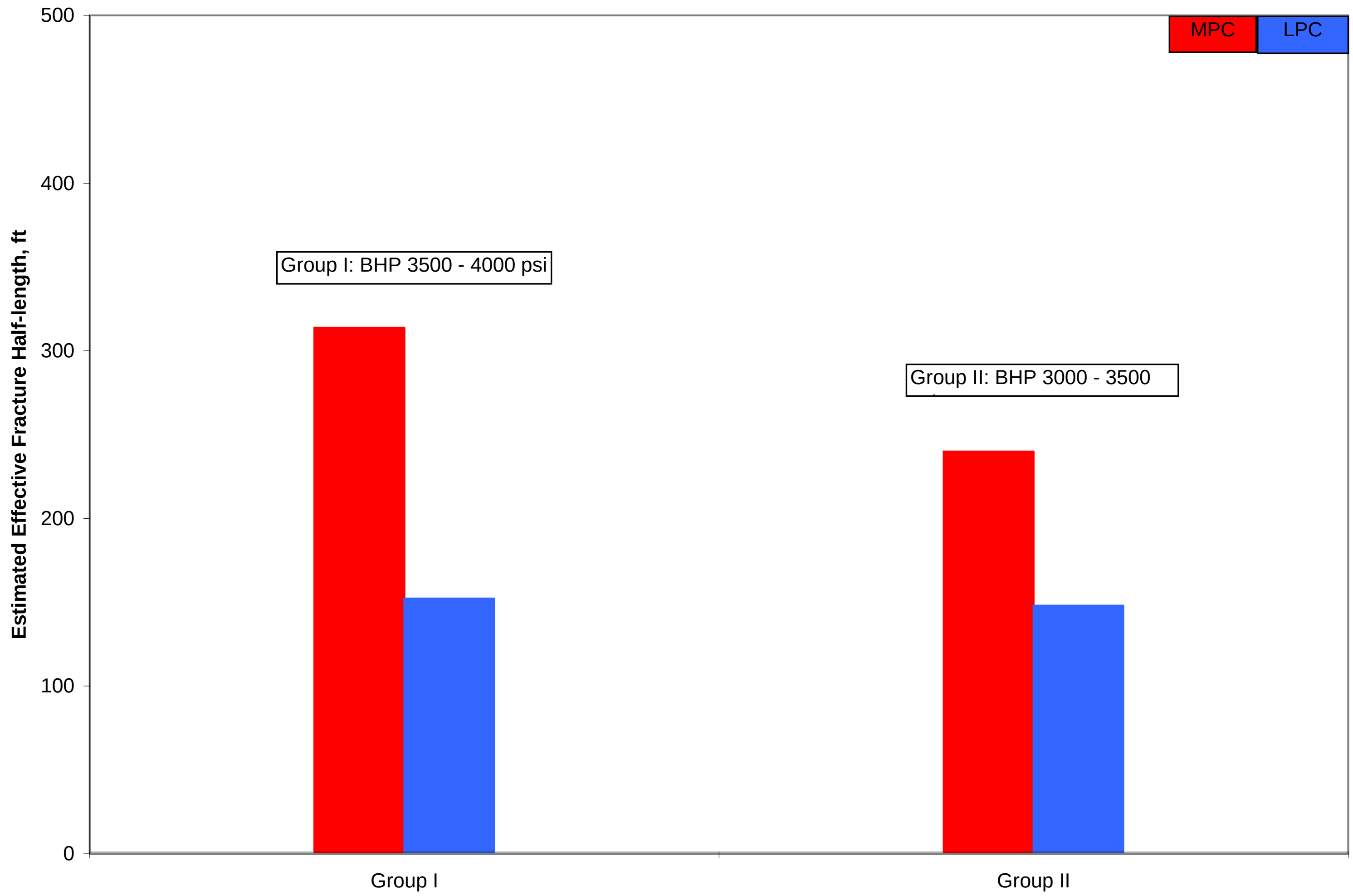

Figure 25: Comparison of Average Estimated Effective Fracture Half-length for Wells in the Carthage Field

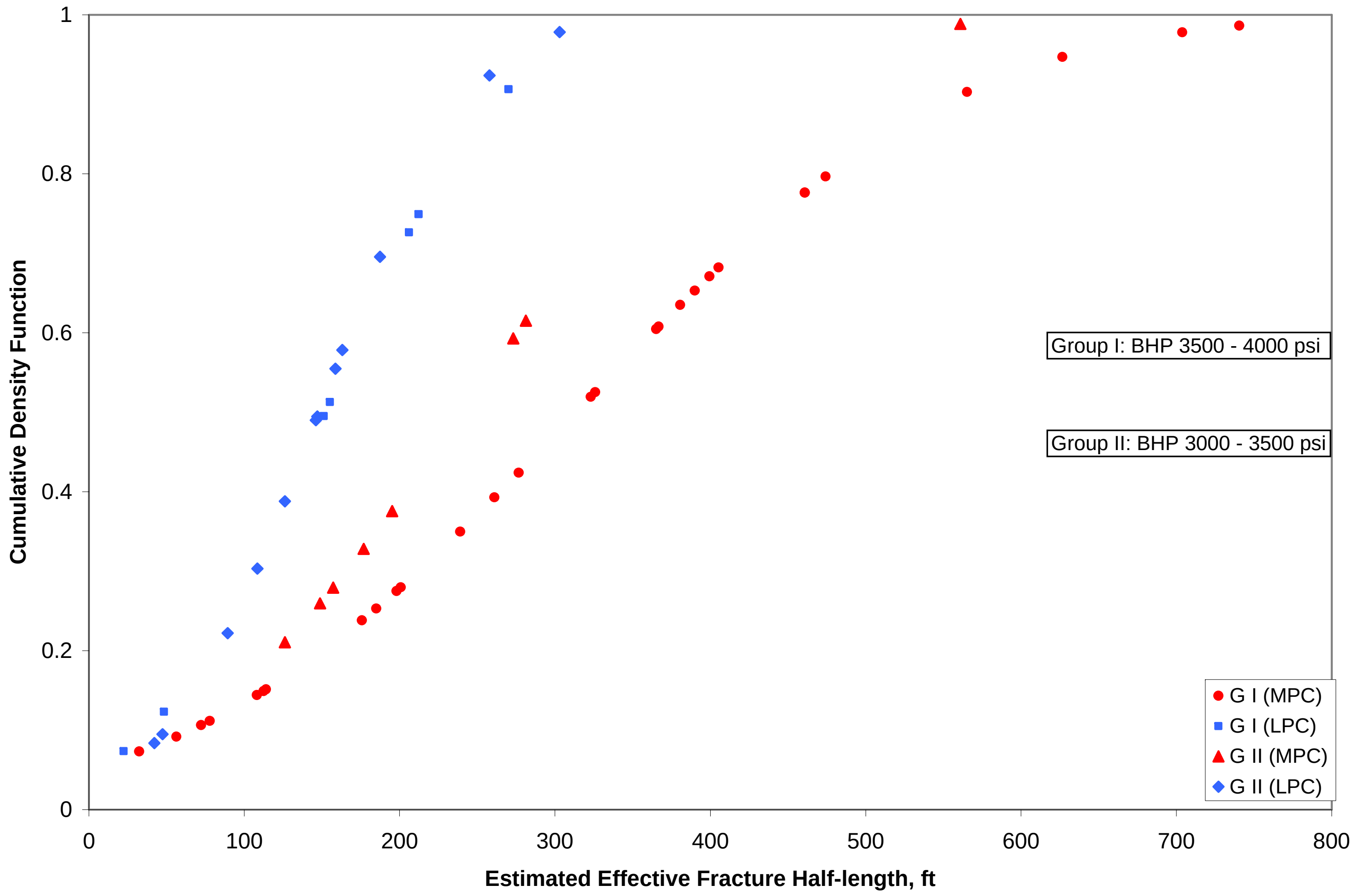

Figure 26: Cumulative Frequency Distribution for Estimated Effective Fracture Half-length for Both Groups and Both Treatments

Numerical Fracture Propagation Simulation

Suitable for Pumping Water Fracture Treatments

Situation 1: Weak upper barrier and thin zone and strong lower barrier. We allowed flowback at the end of pumping. Fig. 27 shows the conductivity contour plot. Fig. 28 shows the width profile and Fig. 29 shows conductivity profile.

Fig. 27 shows the conductivity contour plot for situation1 which is strong lower barrier and weak upper barrier and a thin zone. In this case, all the proppant stays in the payzone and creates a short and moderately conductive fracture as shown in Fig.29. Fig. 28 shows the width profile for situation 1, the maximum width of the fracture is 0.14 inch and which confirms that water fracture treatment can not create wider fractures.

Situation 1a: Weak upper barrier and thick zone and strong lower barrier. Fig. 30 shows the conductivity contour plot. Fig. 31 shows the width profile and Fig. 32 shows conductivity profile.

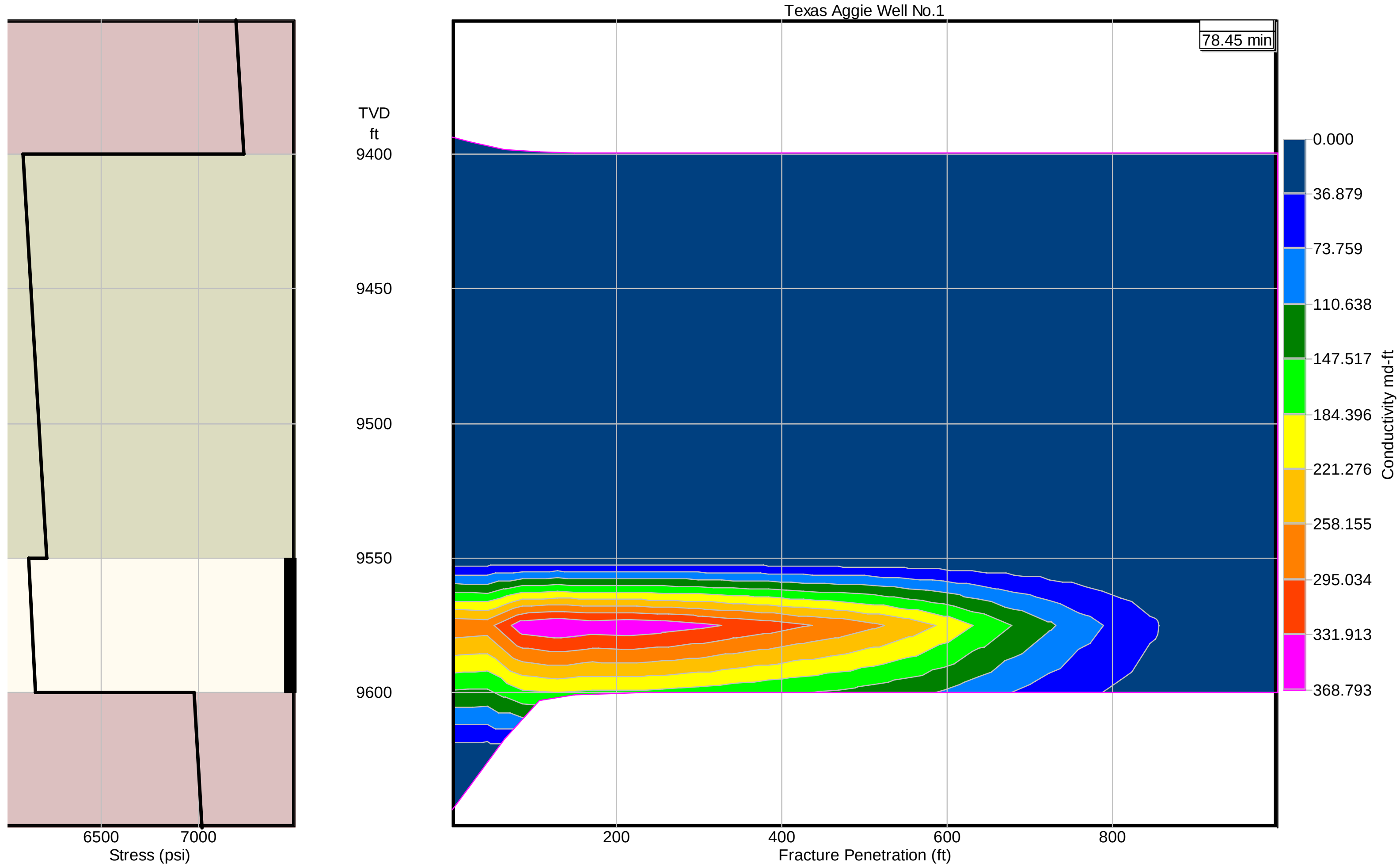

Figure 27: Conductivity Contour Plot for Situation 1 (Water Fracture Treatment)

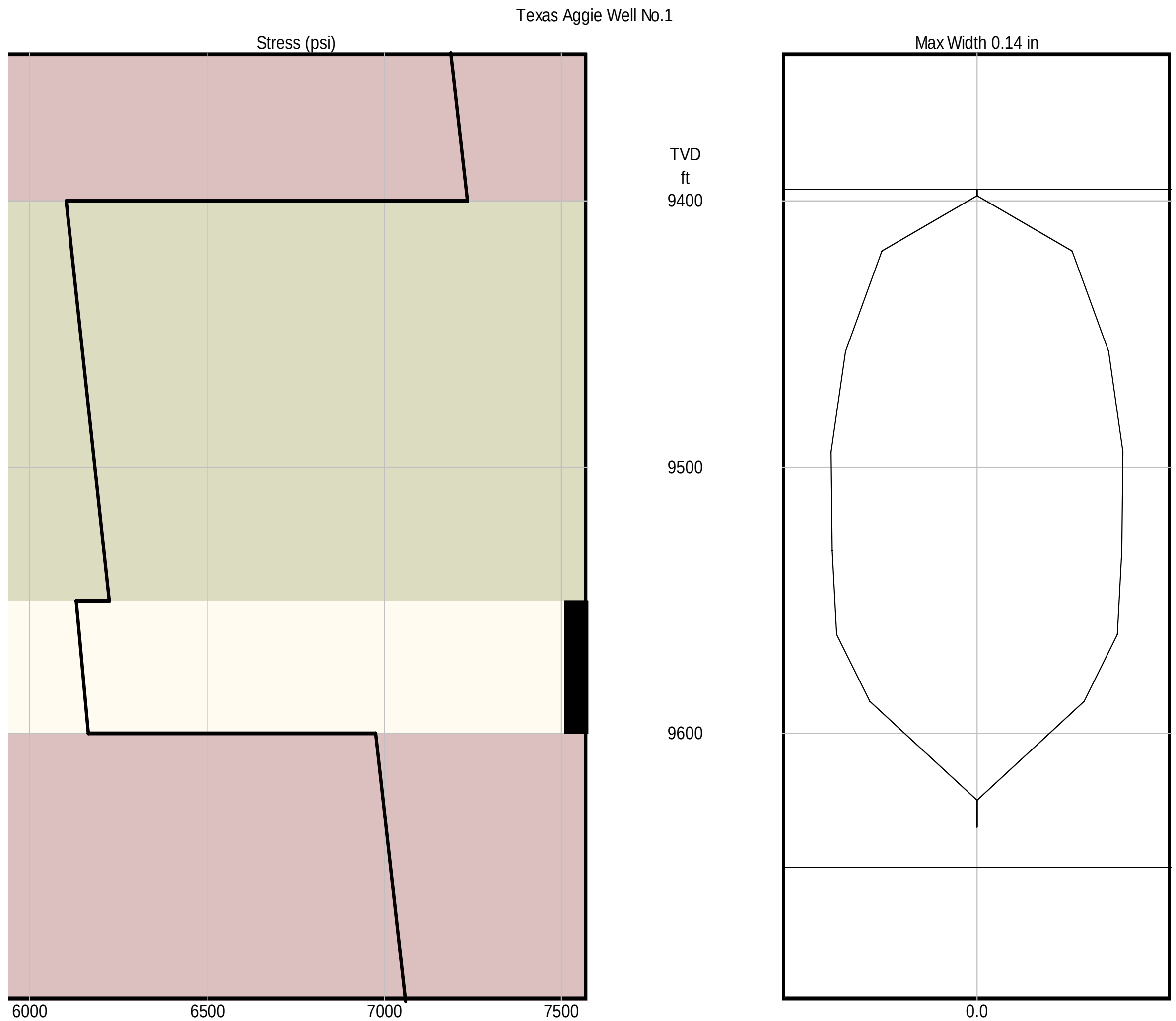

Figure 28: Width Profile for Situation 1 (Water Fracture Treatment)

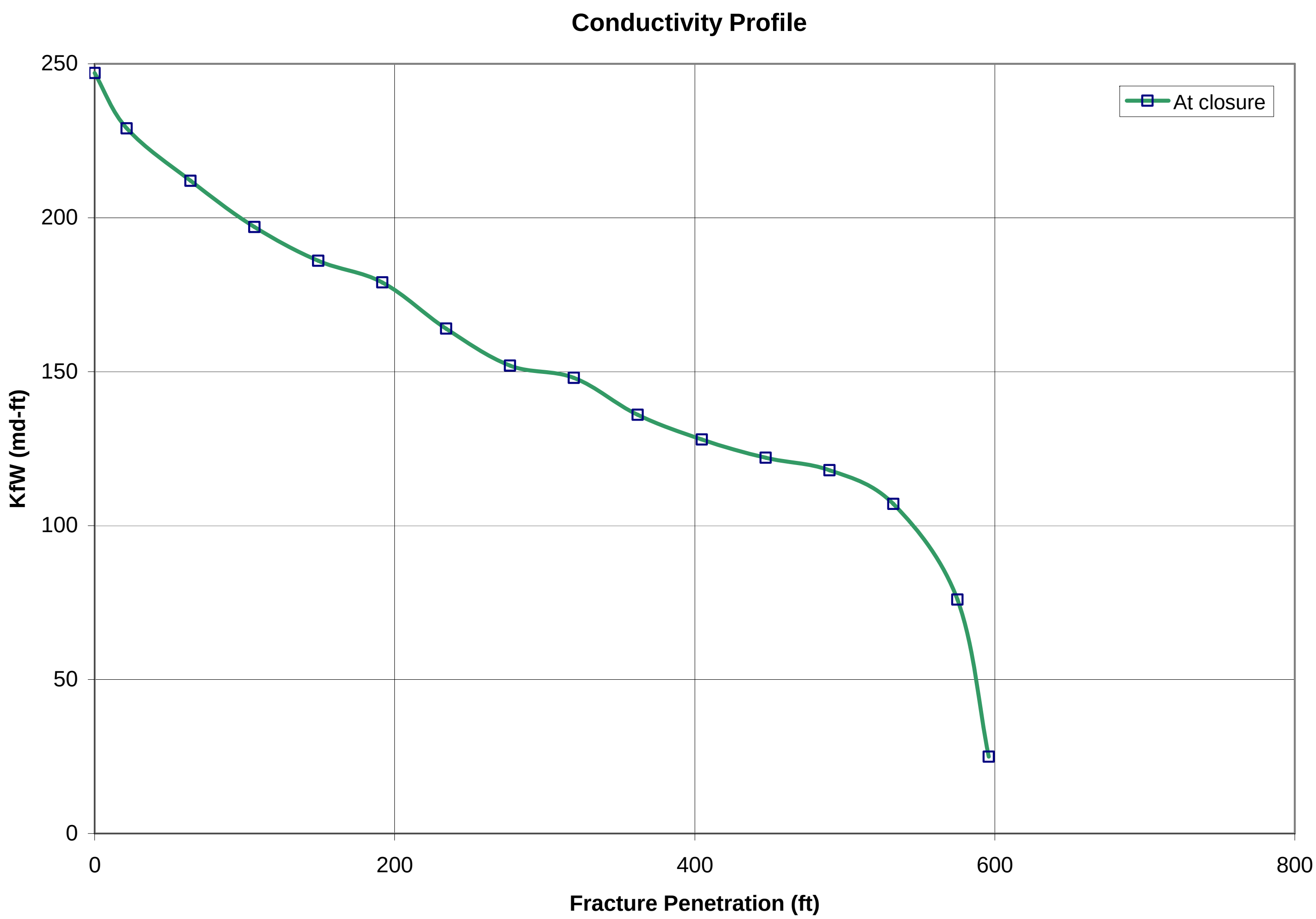

Figure 29: Conductivity Profile for Situation 1 (Water Fracture Treatment)

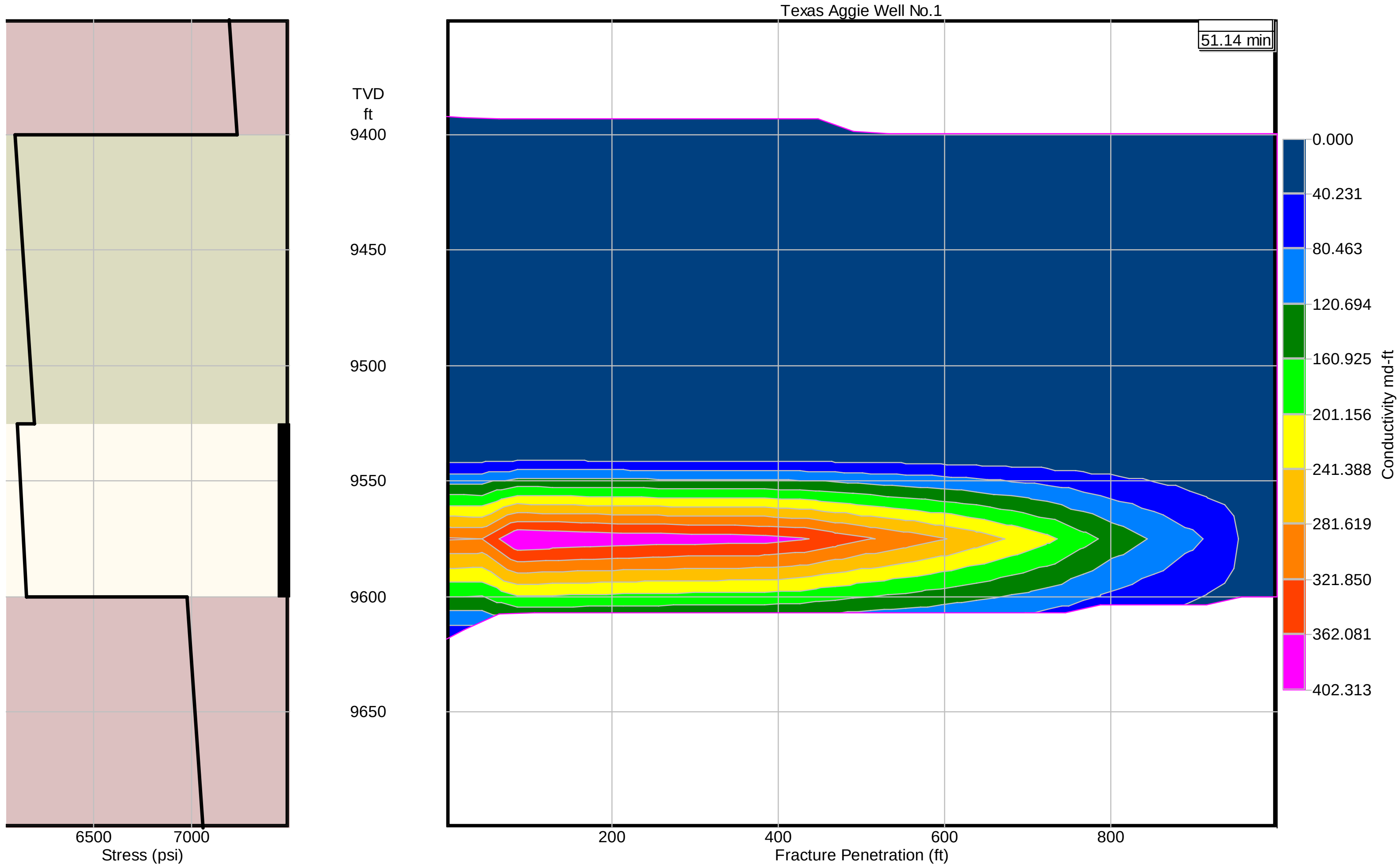

Figure 30: Conductivity Contour Plot for Situation 1a (Water Fracture Treatment)

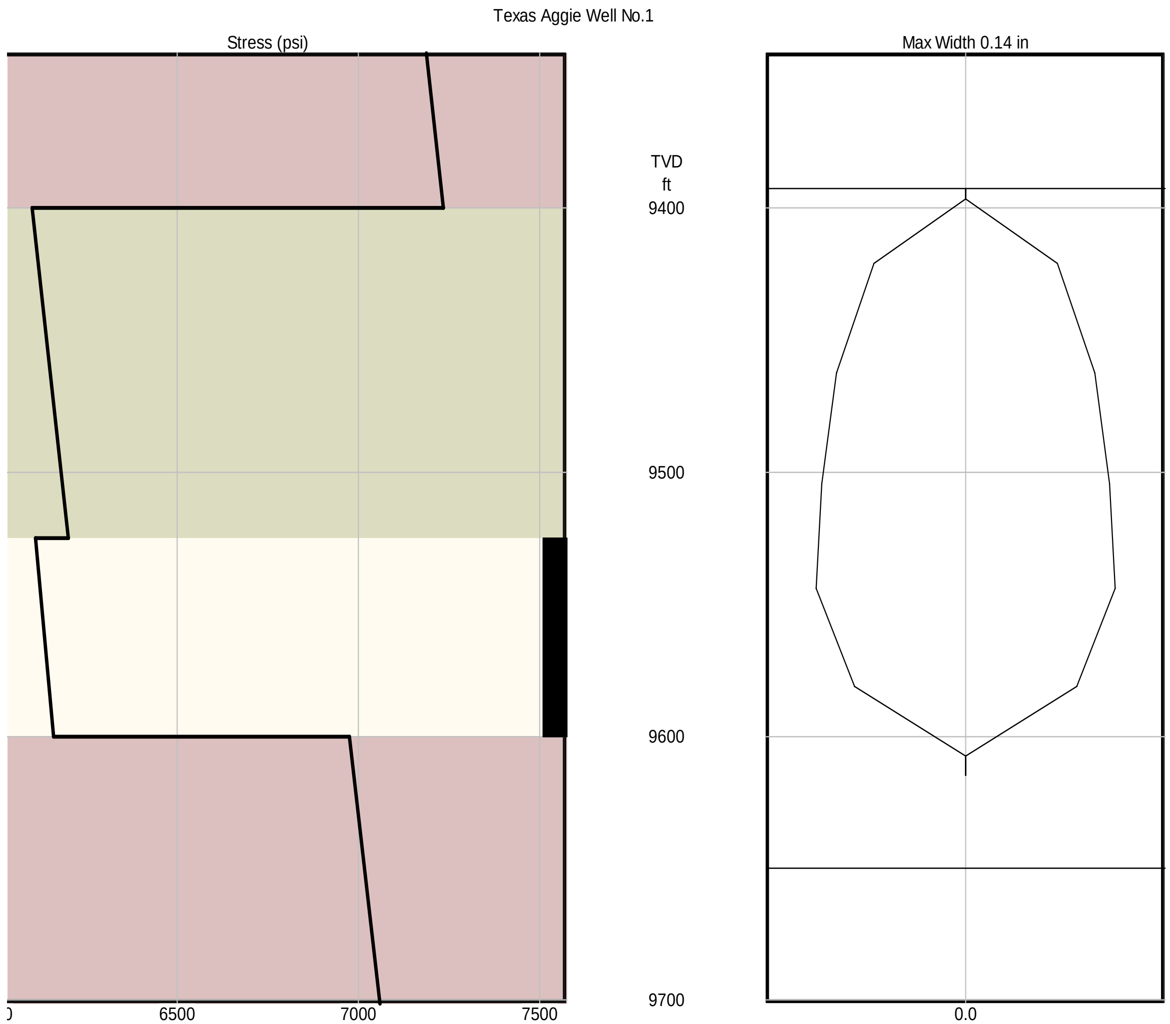

Figure 31: Width Profile for Situation 1a (Water Fracture Treatment)

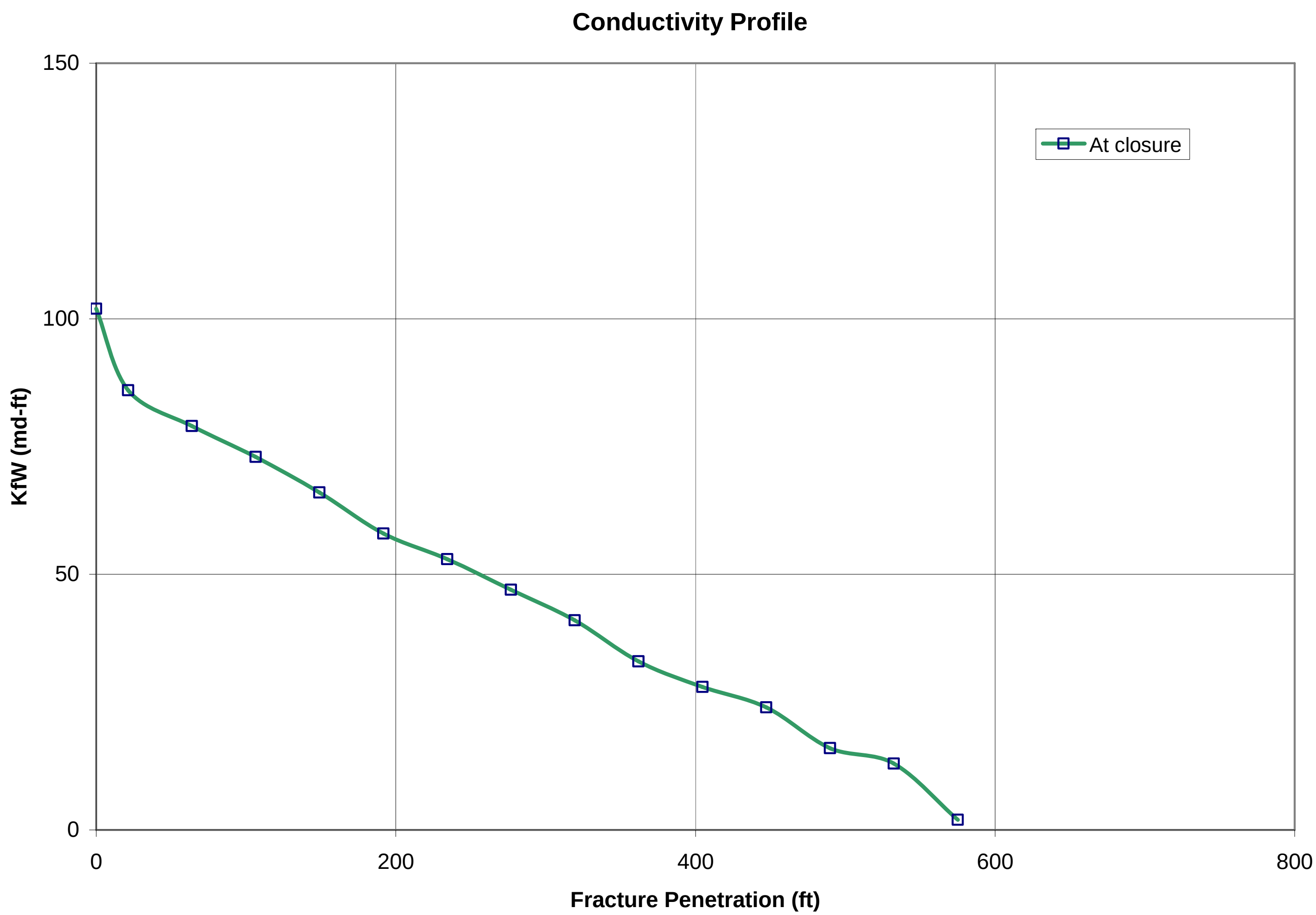

Figure 32: Conductivity Profile for Situation 1a (Water Fracture Treatment)

Situation 1 and situation 1a are basically same in terms of barriers but to look the effect of thickness we increased the thickness of the pay. Fig. 30 shows the conductivity contour plot where it is clear that proppant gets settled in the lower part of the pay leaving top part of pay without proppant. Fig. 32 shows the conductivity profile for situation 1a, the conductivity is fairly low and it decreases rapidly with increasing fracture half-length. The width profile is fairly similar for both the situations.

Situation 2: Weak upper barrier and thin zone and moderate lower barrier with high Young's modulus. Fig. 33 shows the conductivity contour plot. Fig. 34 shows the width profile and Fig. 35 shows conductivity profile.

Fig. 33 shows the conductivity contour plot for situation 2 which is moderate lower barrier with high Young's modulus and weak upper barrier and a thin zone. In this case also, all the proppant stays in the payzone and creates a short and sustained moderately conductive fracture as shown in Fig.35. Fig. 34 shows the width profile for situation 2, the maximum width of the fracture is 0.13 inch.

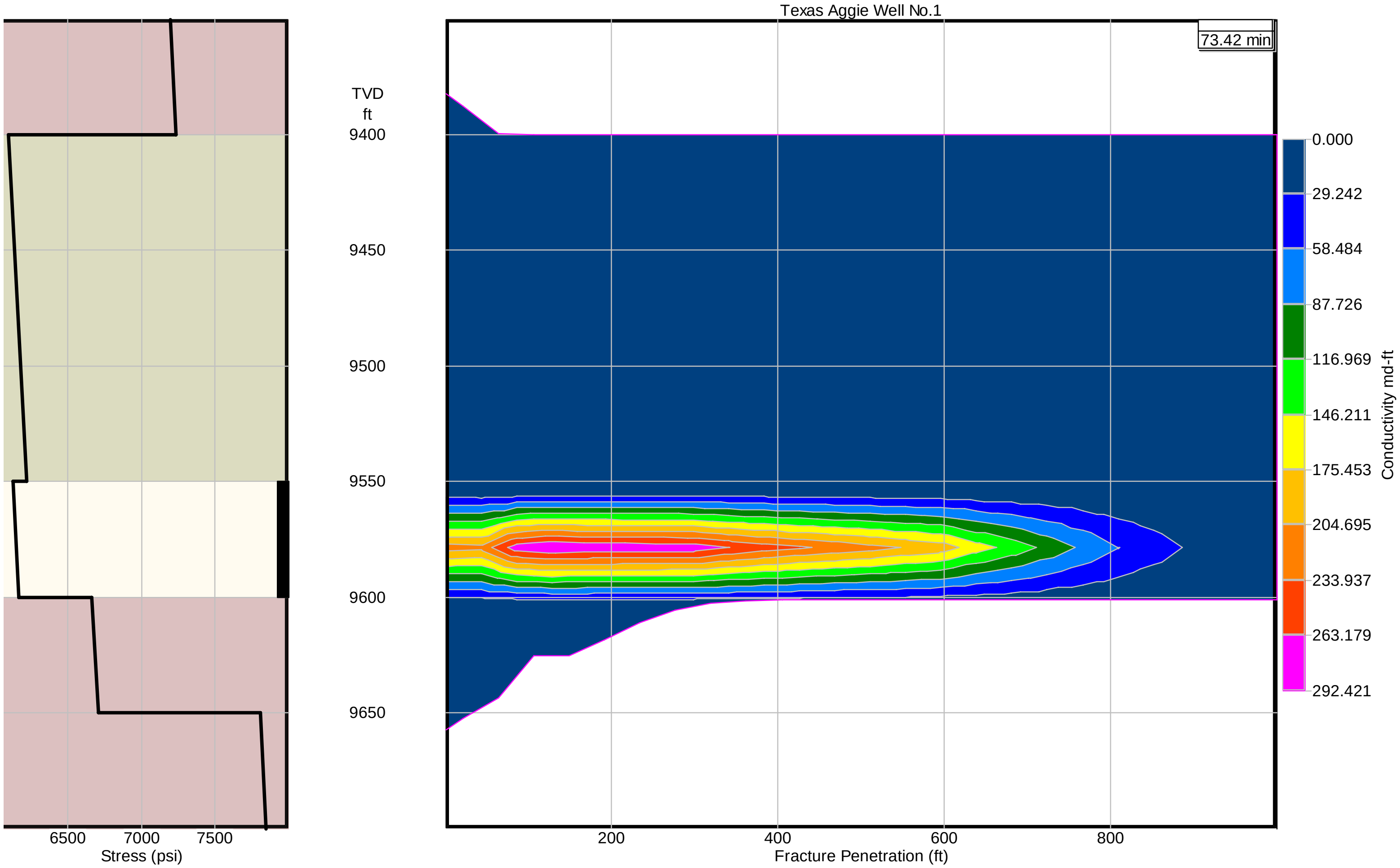

Figure 33: Conductivity Contour Plot for Situation 2 (Water Fracture Treatment)

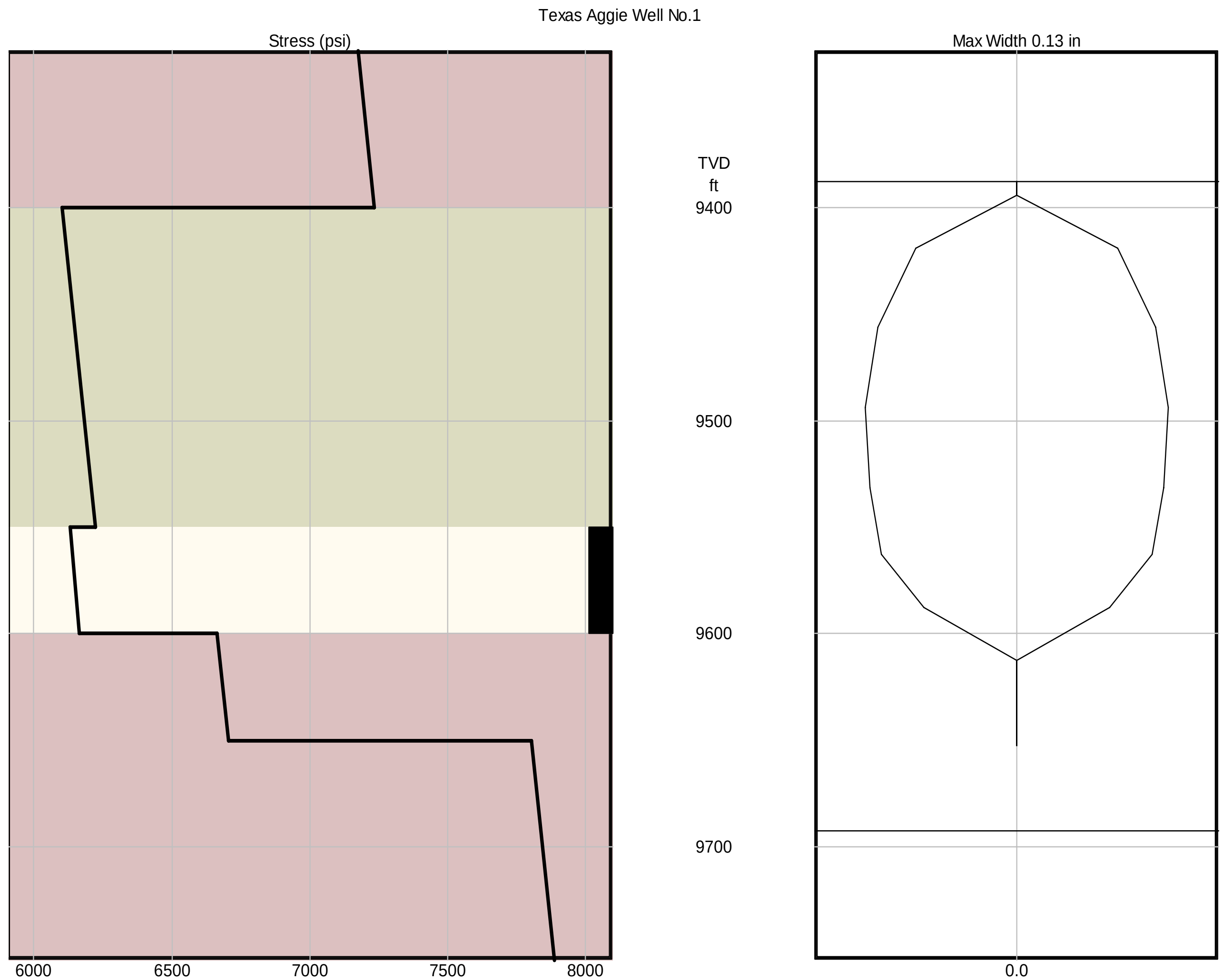

Figure 34: Width Profile for Situation 2 (Water Fracture Treatment)

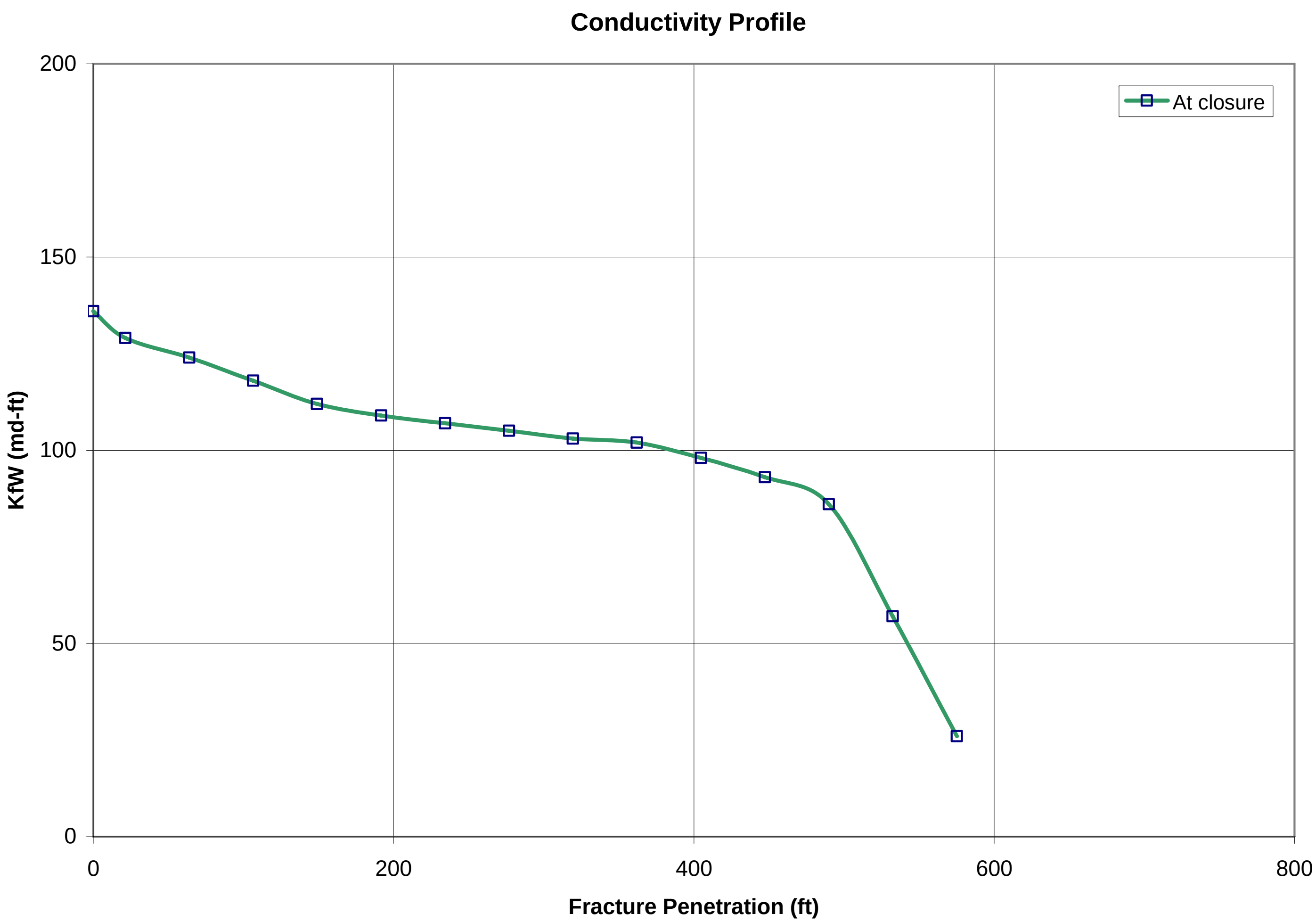

Figure 35: Conductivity Profile for Situation 2 (Water Fracture Treatment)

Unsuitable for Pumping Water Fracture Treatments

Situation 3: Weak lower barrier. Fig. 36 shows the conductivity contour plot which illustrates that all proppant settles down in the zone below the targeted formation. Fig. 37 shows width profile. In this case, the conductivity is zero across the pay.

Situation 3 represents a weak lower barrier. Fig. 36 shows the conductivity contour plot for water fracture treatment which illustrates that all proppant settles down in the zone below the pay. In this case, the conductivity is zero across the pay. The width profile as shown in Fig. 37 is different from that of the width profiles for situations 1 and 2. In situation 1 and 2 water fracture treatment could not able to create fracture in the lower zone below the pay. But in situation 3, water fracture treatment creates a wider fracture in the lower zone and thus all the proppant gets settled as water is not viscous enough to retain and carry proppant deep into the fracture.

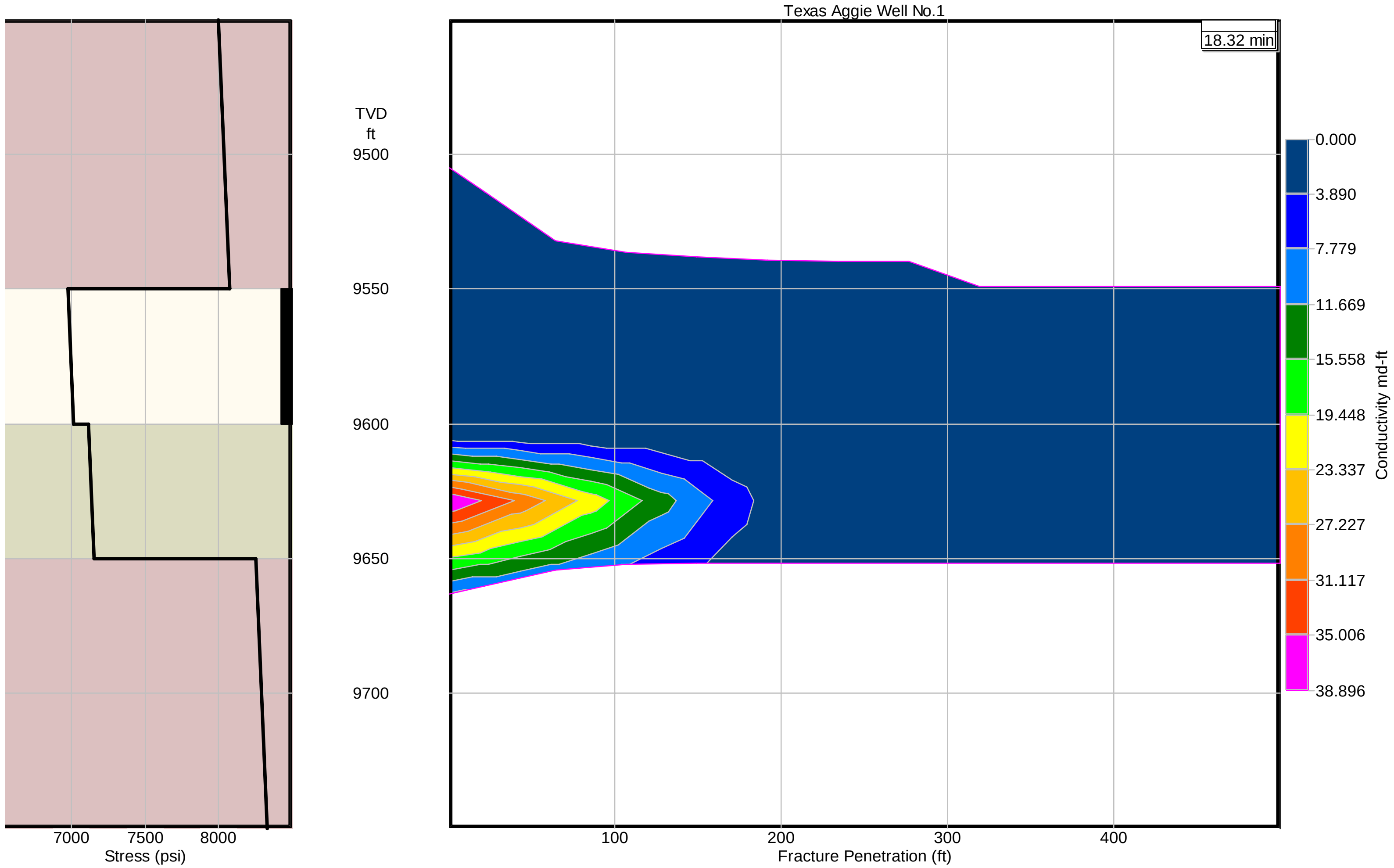

Figure 36: Conductivity Contour Plot for Situation 3 (Water Fracture Treatments)

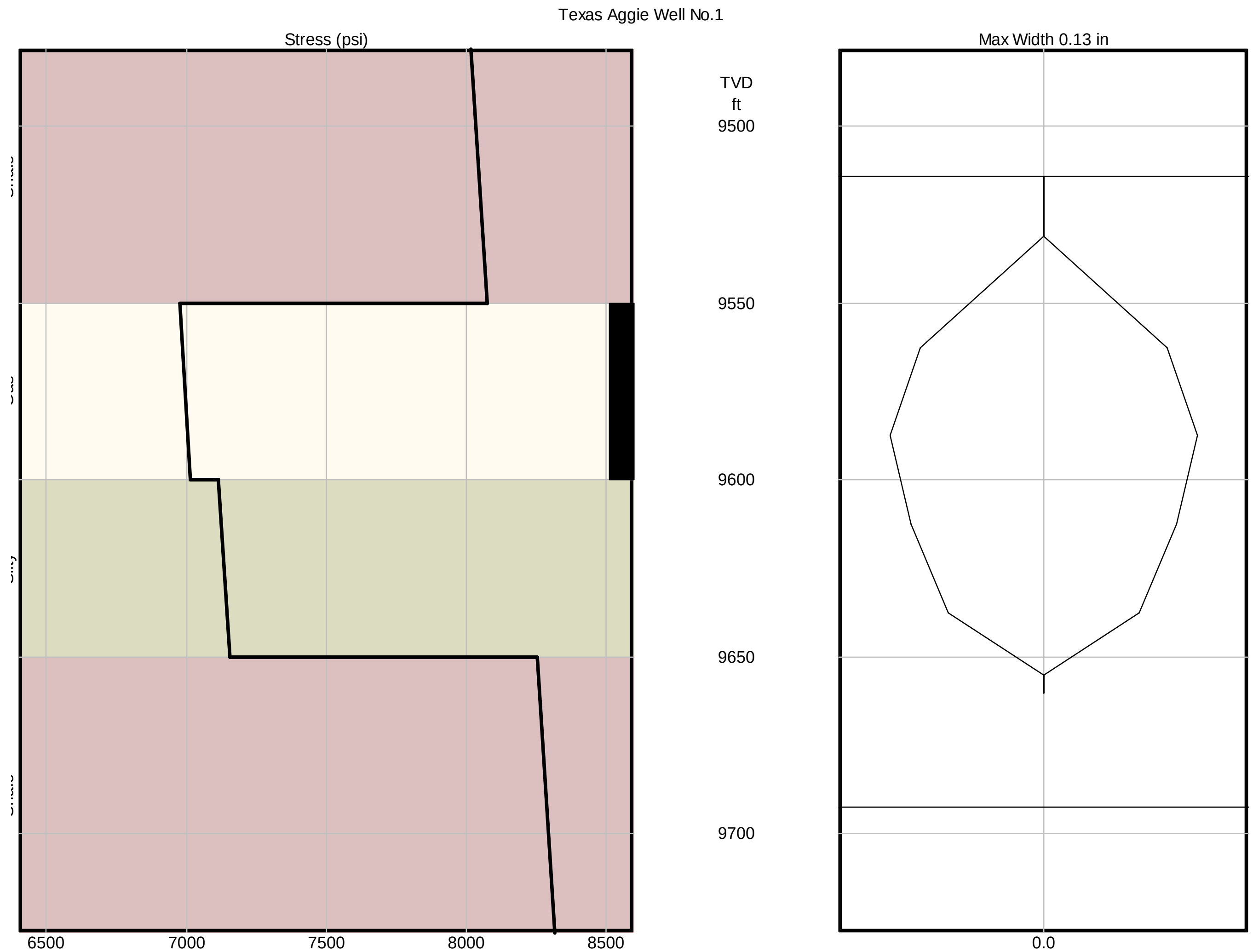

Figure 37: Width Profile for Situation 3 (Water Fracture Treatments)

Situation 4: Moderate lower barrier with low Young's modulus. Fig. 38 shows the conductivity contour plot which shows that all proppant settles down in the zone below the targeted formation. Fig. 39 shows width profile. In this case, the conductivity is zero across the pay.

Situation 4 is quite similar to situation 2 but this time it has a lower barrier with low Young's modulus. If we look at Fig. 34 and Fig. 39, there is significant difference in the width profile in the zone below the pay. In situation 2 where we have high Young's modulus of the lower barrier there we did not see any fracture growth while in situation 4 where we have low Young's modulus there is a little width growth where all the proppant gets settled despite similar stress profile. The conductivity contour plot shown in Fig. 38 is similar to the situation 3 conductivity contour plot shown in Fig. 36. In this case also, the conductivity is zero across the pay.

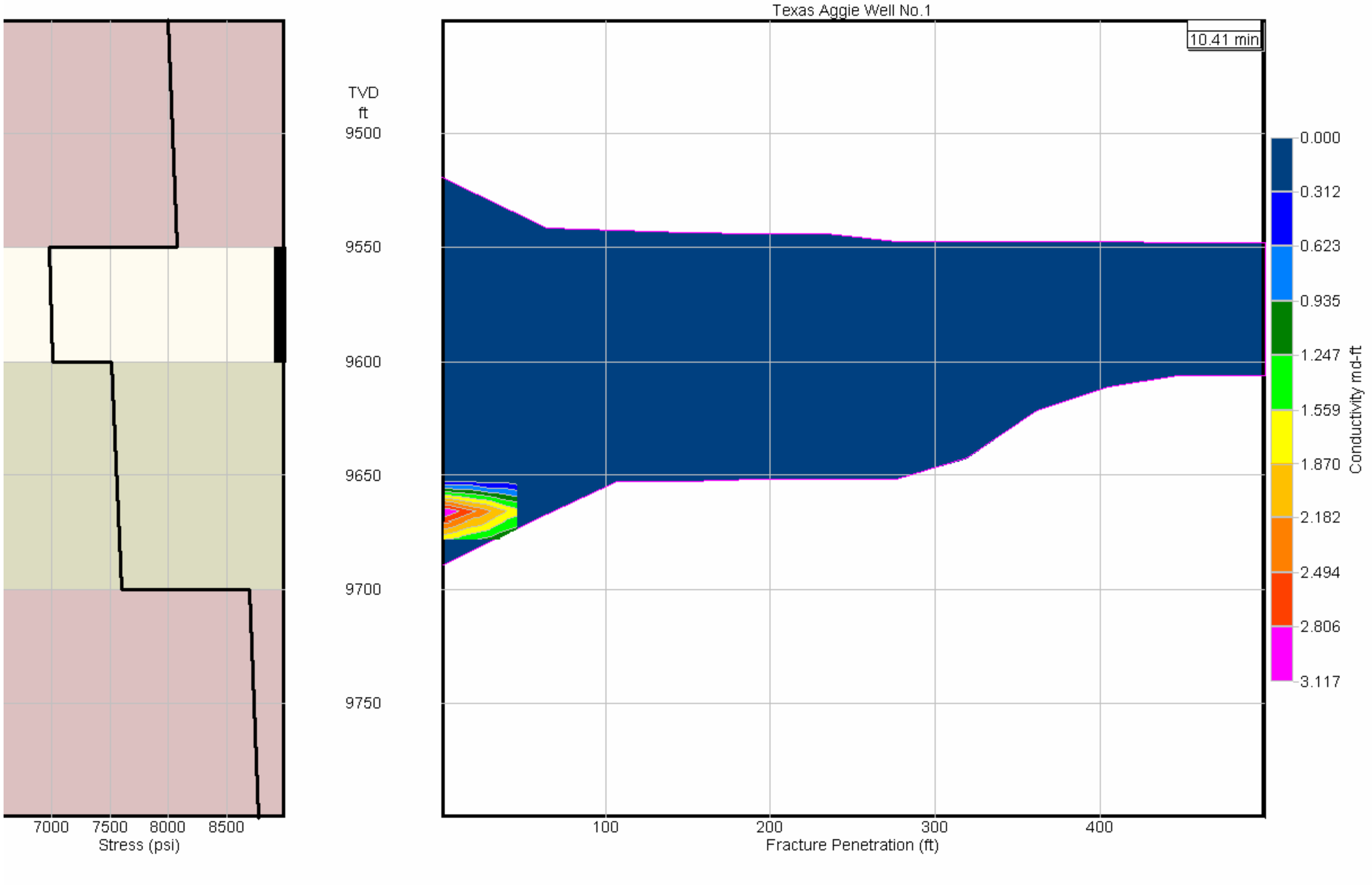

Figure 38: Conductivity Contour Plot for Situation 4 (Water Fracture Treatments)

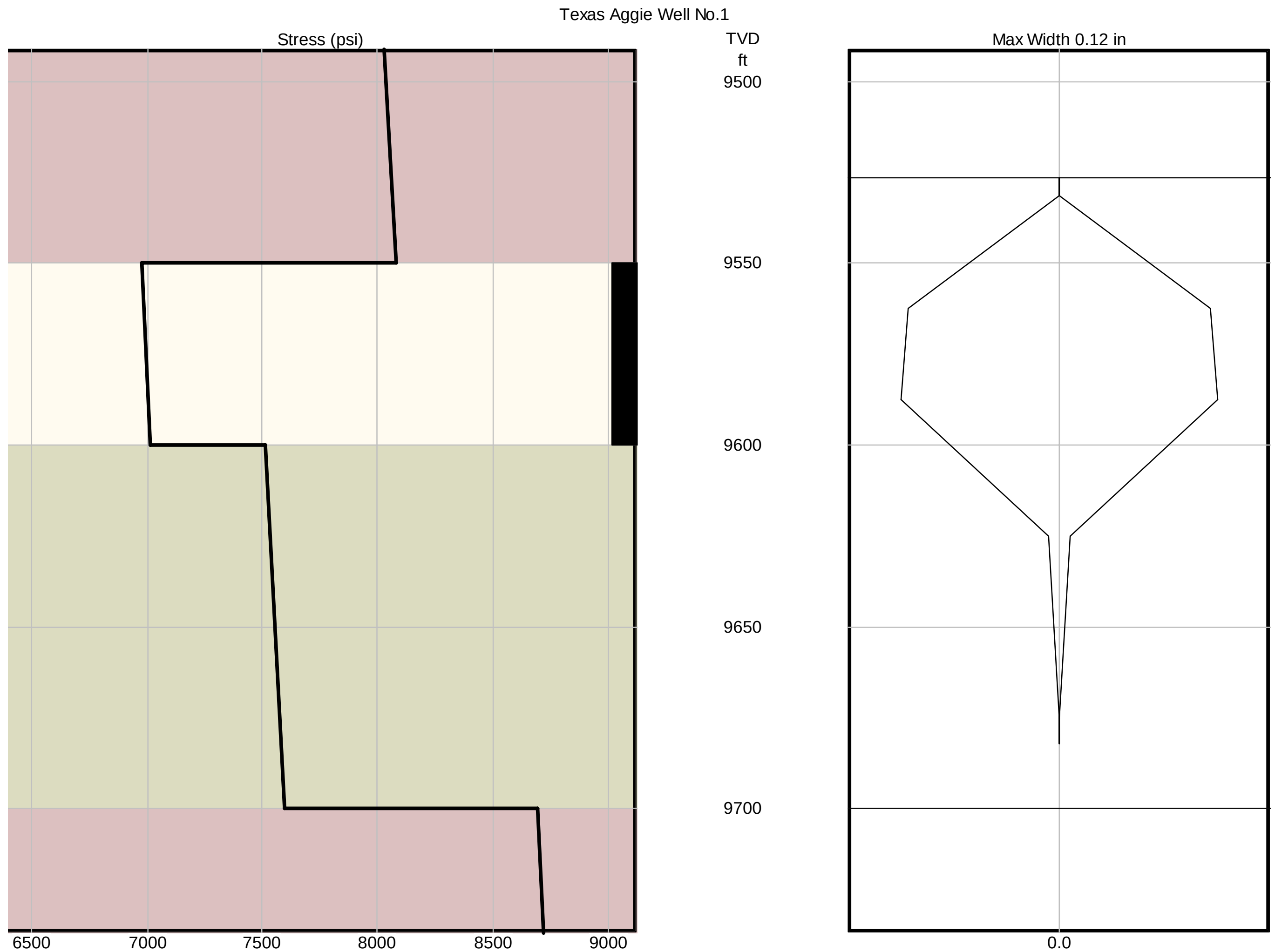

Figure 39: Width Profile for Situation 4 (Water Fracture Treatments)

Alternative Fracture Treatments

Situation 3: Fig. 40 shows the conductivity contour plot which shows that all proppant stays in the zone. Fig. 41 shows conductivity profile for gel fracture treatment and Fig. 42 shows conductivity profile for gel fracture treatment. Fig. 43 shows the conductivity contour plot. Fig. 44 shows conductivity profile for gel fracture treatment and Fig. 45 shows conductivity profile for hybrid fracture treatment.

Fig. 40 shows the conductivity contour plot for gel fracture treatment for situation 3 which illustrates that all proppant stays in the payzone and creates a long and conductive fracture as shown in Fig.42. Fig. 41 shows the width profile for situation 3 for gel fracture treatment, the maximum width of the fracture is 0.49 inch and which is nearly four times the maximum width created by water fracture treatment for situation 3.

The conductivity contour plot for hybrid fracture treatment for situation 3 shown in Fig. 43 illustrates that all the proppant stays in the pay zone and creates a long and highly conductive fracture as shown in Fig. 45. The width profile for gel fracture treatment and hybrid fracture treatment is similar.

Situation 4: Fig. 46 shows the conductivity contour plot which shows that all proppant stays in the zone. Fig. 47 shows conductivity profile for gel fracture treatment and Fig. 48 shows conductivity profile for gel fracture treatment. Fig. 49 shows the conductivity contour plot. Fig. 50 shows conductivity profile for gel fracture treatment and Fig. 51 shows conductivity profile for hybrid fracture treatment.

Fig. 46 and Fig. 49 show the conductivity contour plot for situation 4 for gel fracture treatment and hybrid fracture treatment respectively which are fairly similar. The width profiles are also similar. But the conductivity profiles are different; the fracture created by hybrid fracture treatment has high and sustained conductivity as shown in Fig. 51 than the fracture created by gel fracture treatment which is shown in Fig. 48.

So when we have a strong barrier at bottom and a thin zone we may get adequate stimulation using water fracture treatment. When we have a moderate lower barrier with high Young's modulus and thin zone is also a suitable situation to pump water fracture treatment. But when we have a weak barrier at bottom or a moderate barrier with low Young's modulus then it is better to not pump water fracture treatments. In this situation, hybrid fracture treatments would provide adequate stimulation economically for reservoirs condition similar to that of Cotton Valley sands in East Texas basin.

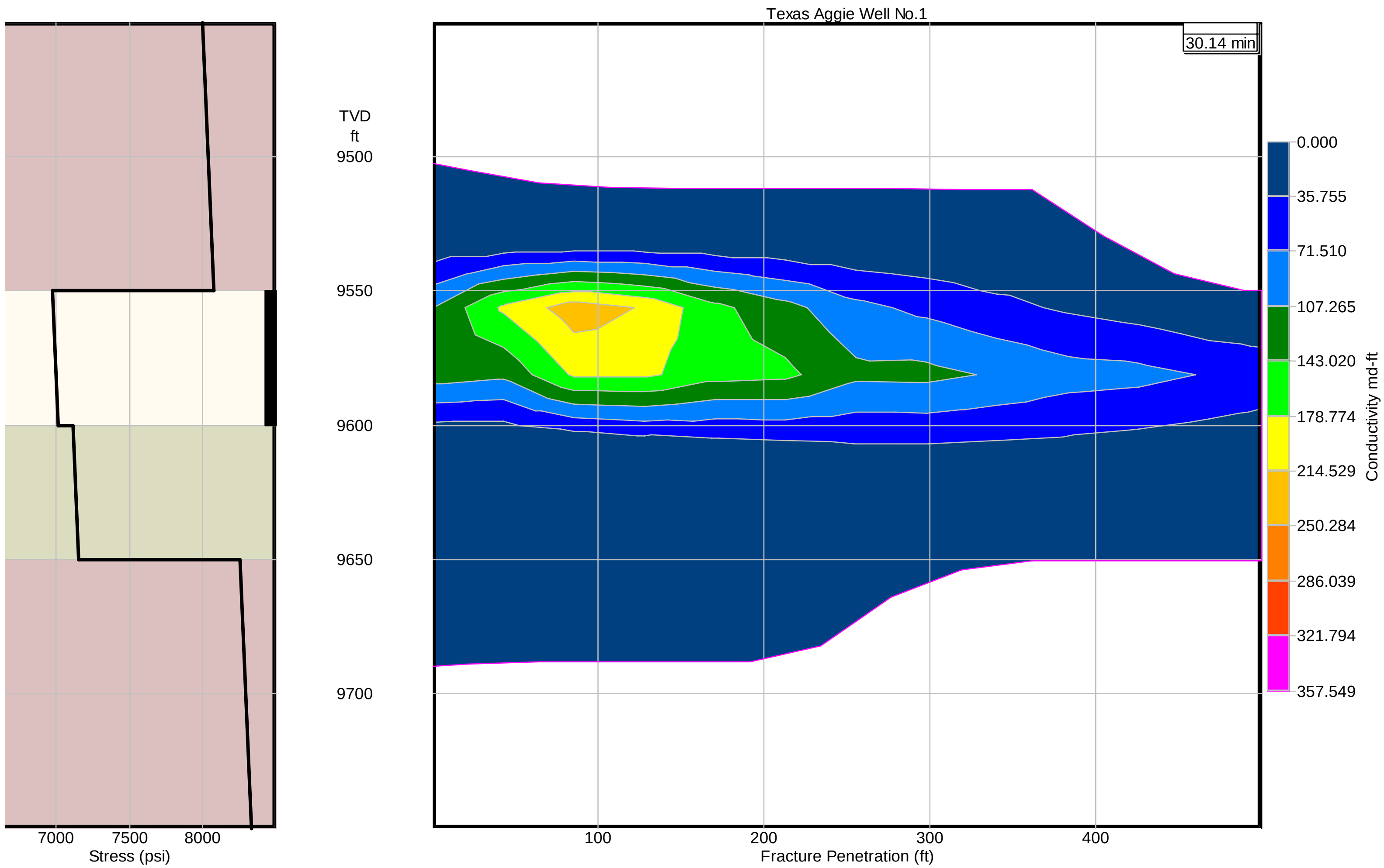

Figure 40: Conductivity Contour Plot for Situation 3 (Gel Fracture Treatments)

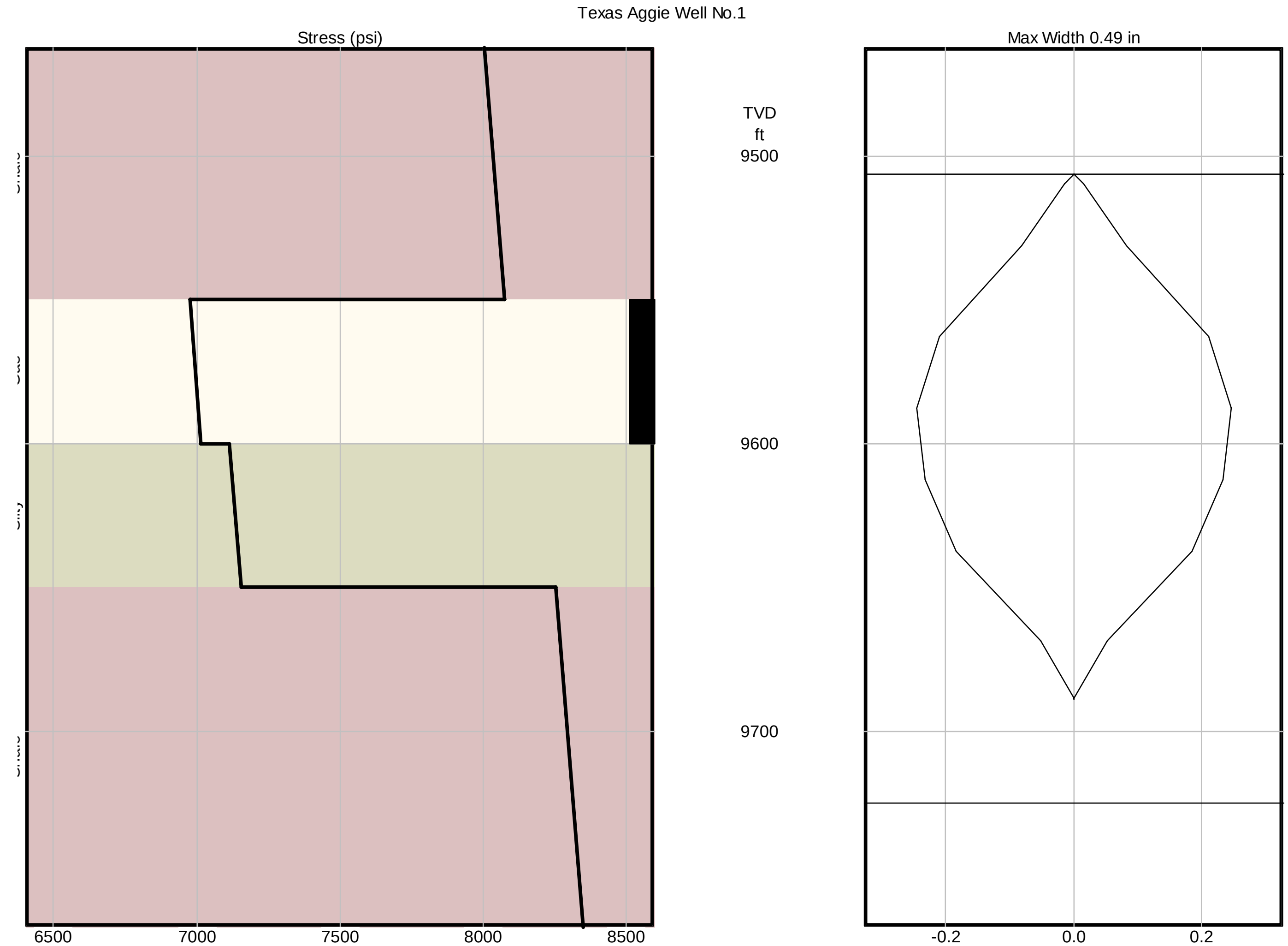

Figure 41: Width Profile for Situation 3 (Gel Fracture Treatments)

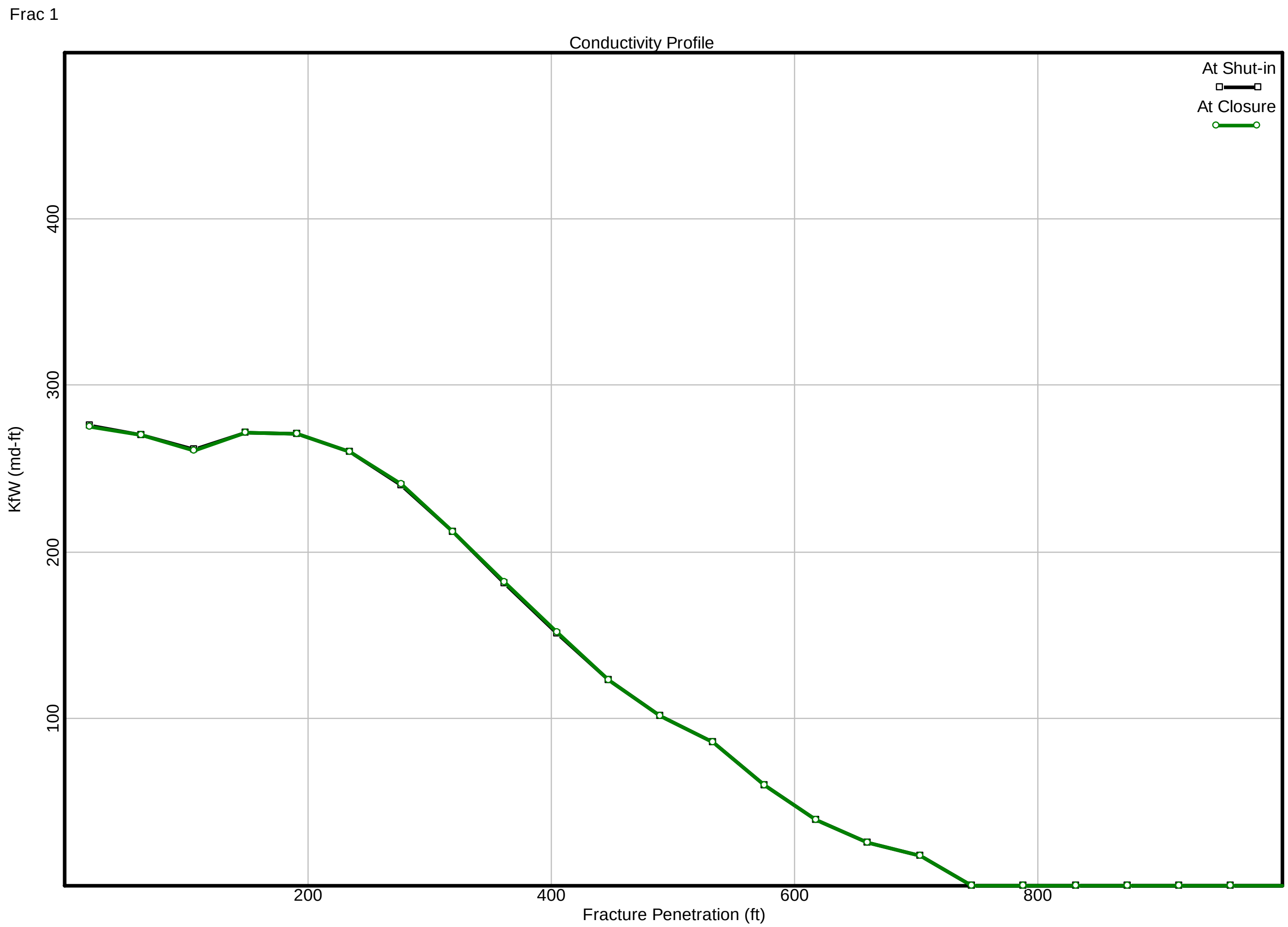

Figure 42: Conductivity Profile for Situation 3 (Gel Fracture Treatments)

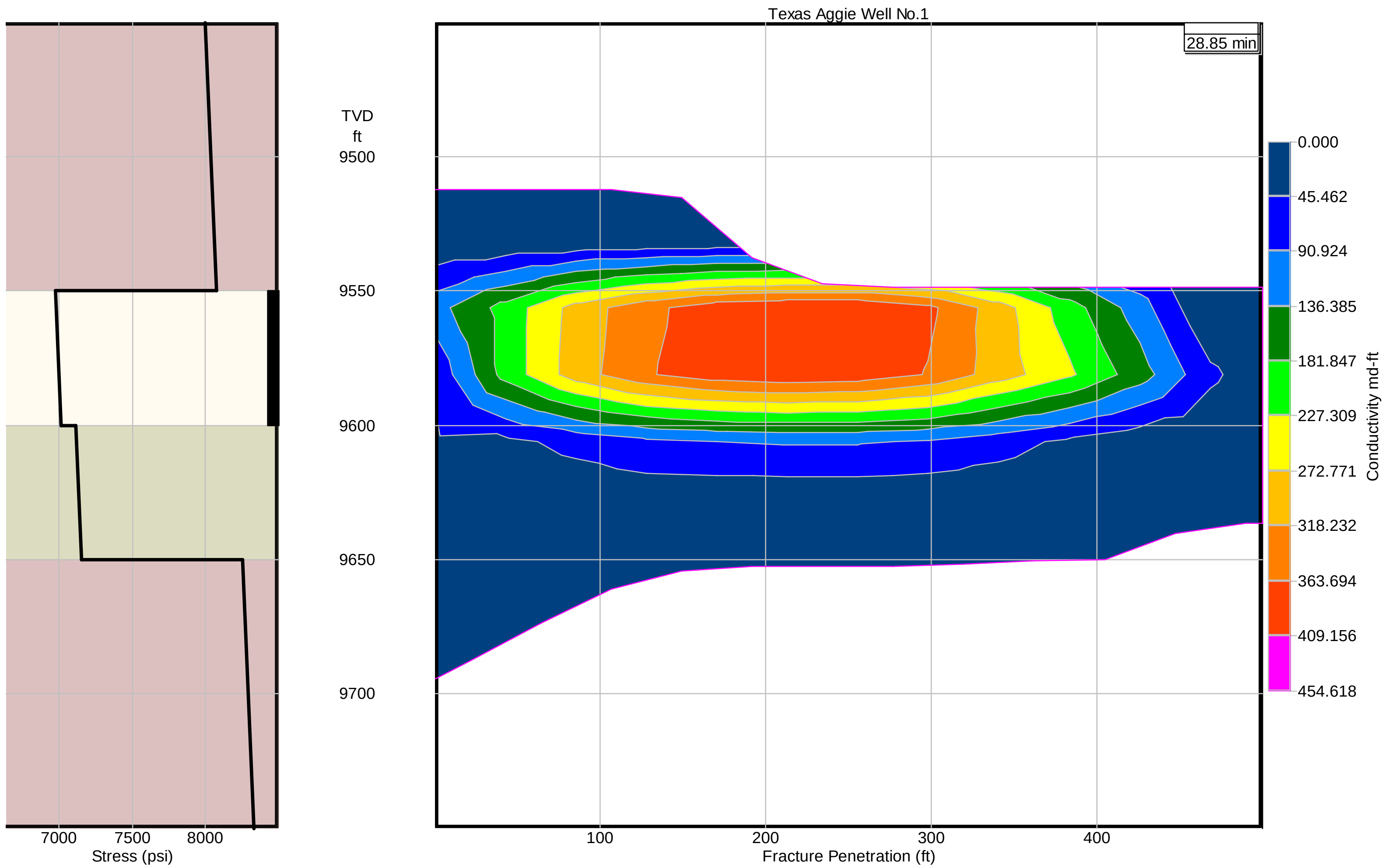

Figure 43: Conductivity Contour Plot for Situation 3 (Hybrid Fracture Treatments)

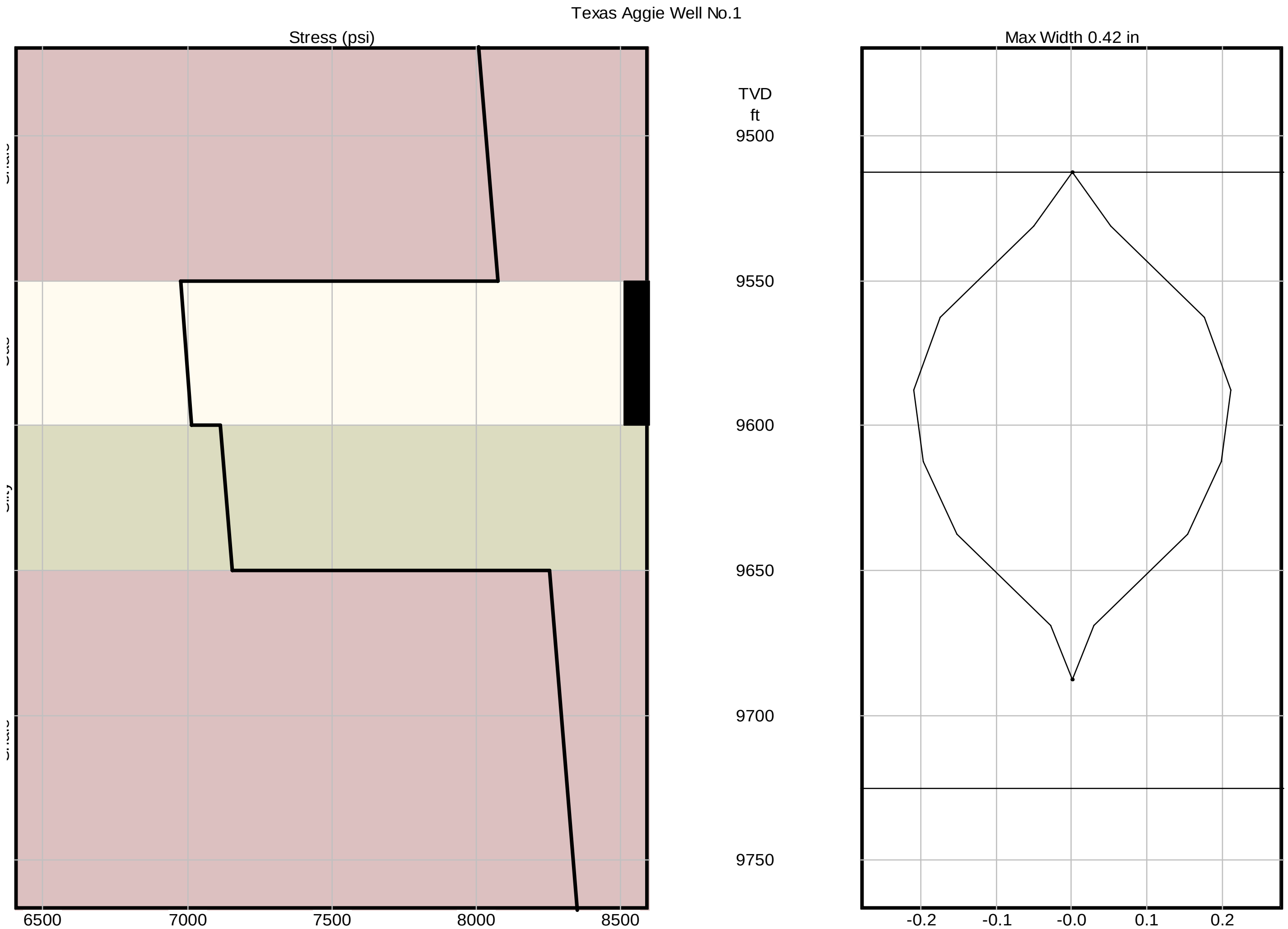

Figure 44: Width Profile for Situation 3 (Hybrid Fracture Treatments)

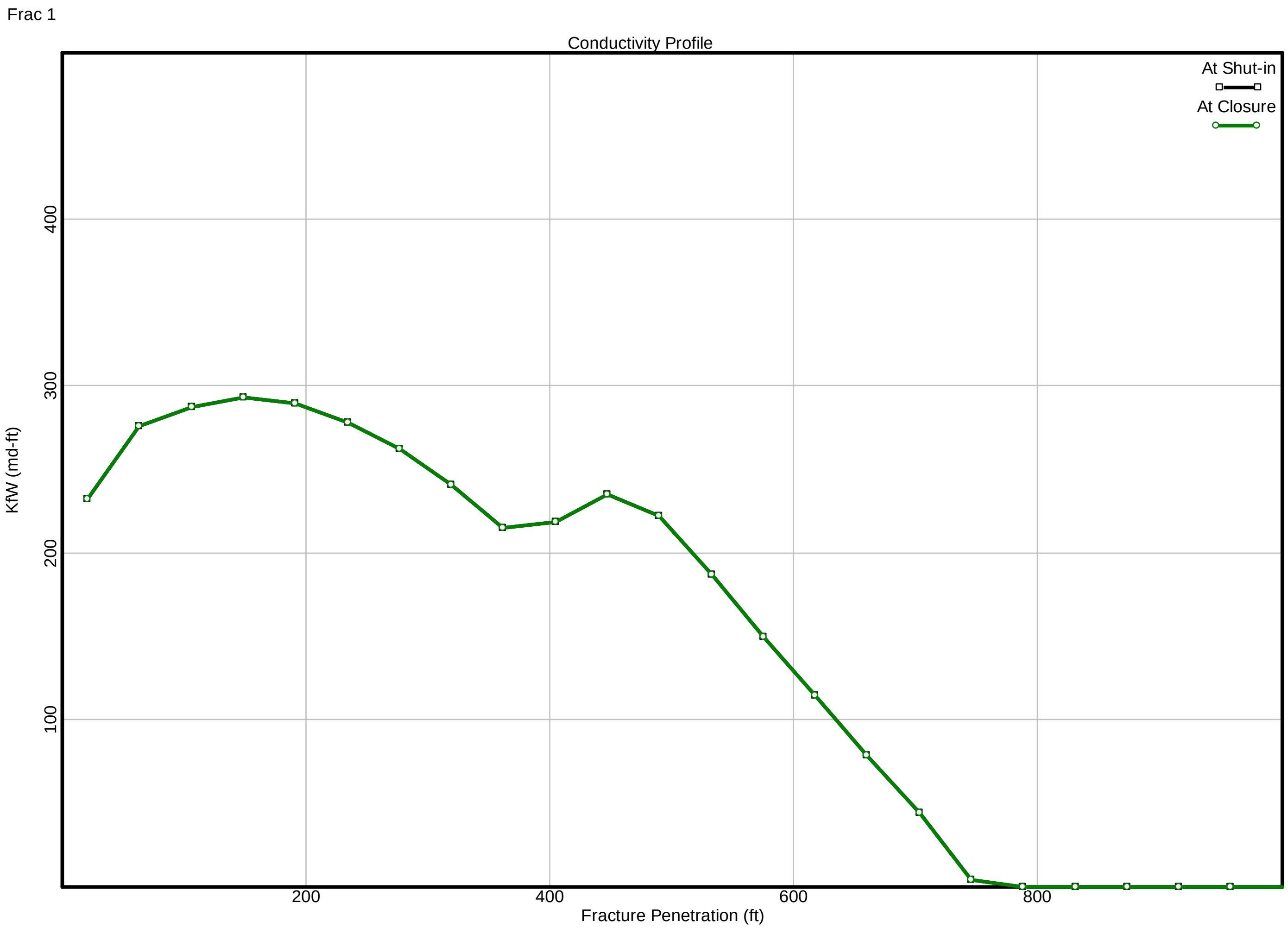

Figure 45: Conductivity Profile for Situation 3 (Hybrid Fracture Treatments)

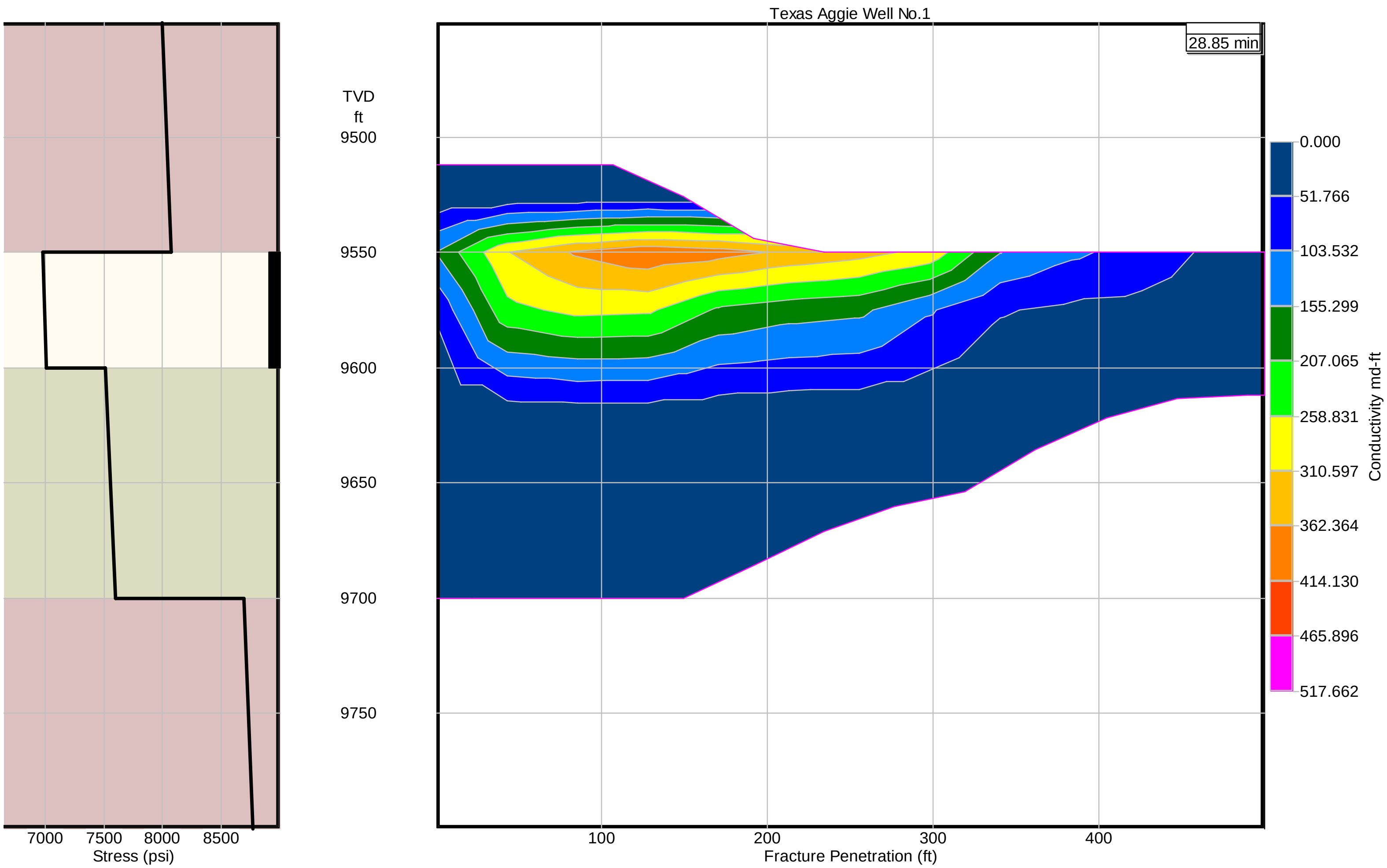

Figure 46: Conductivity Contour Plot for Situation 4 (Gel Fracture Treatments)

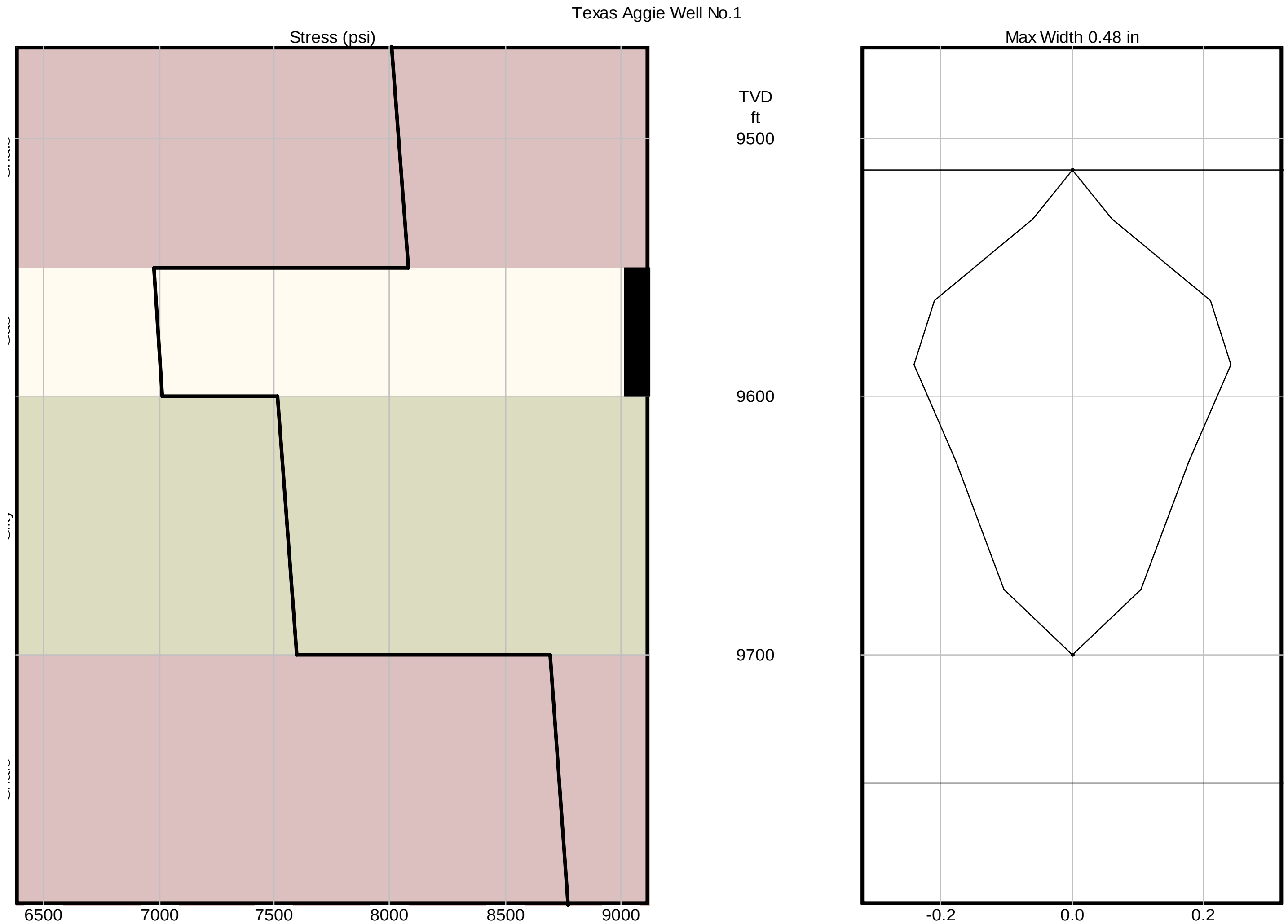

Figure 47: Width Profile for Situation 4 (Gel Fracture Treatments)

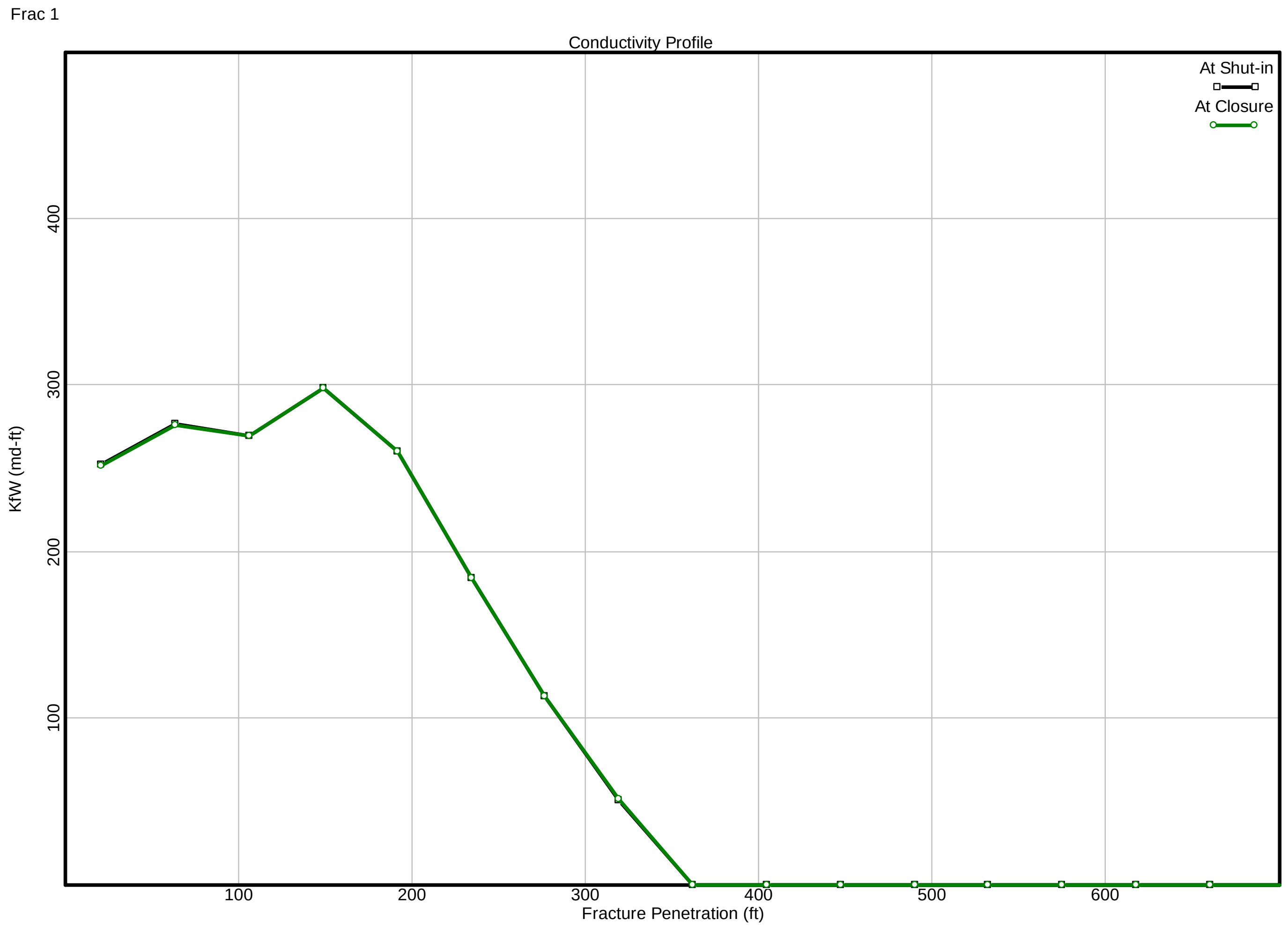

Figure 48: Conductivity Profile for Situation 4 (Gel Fracture Treatments)

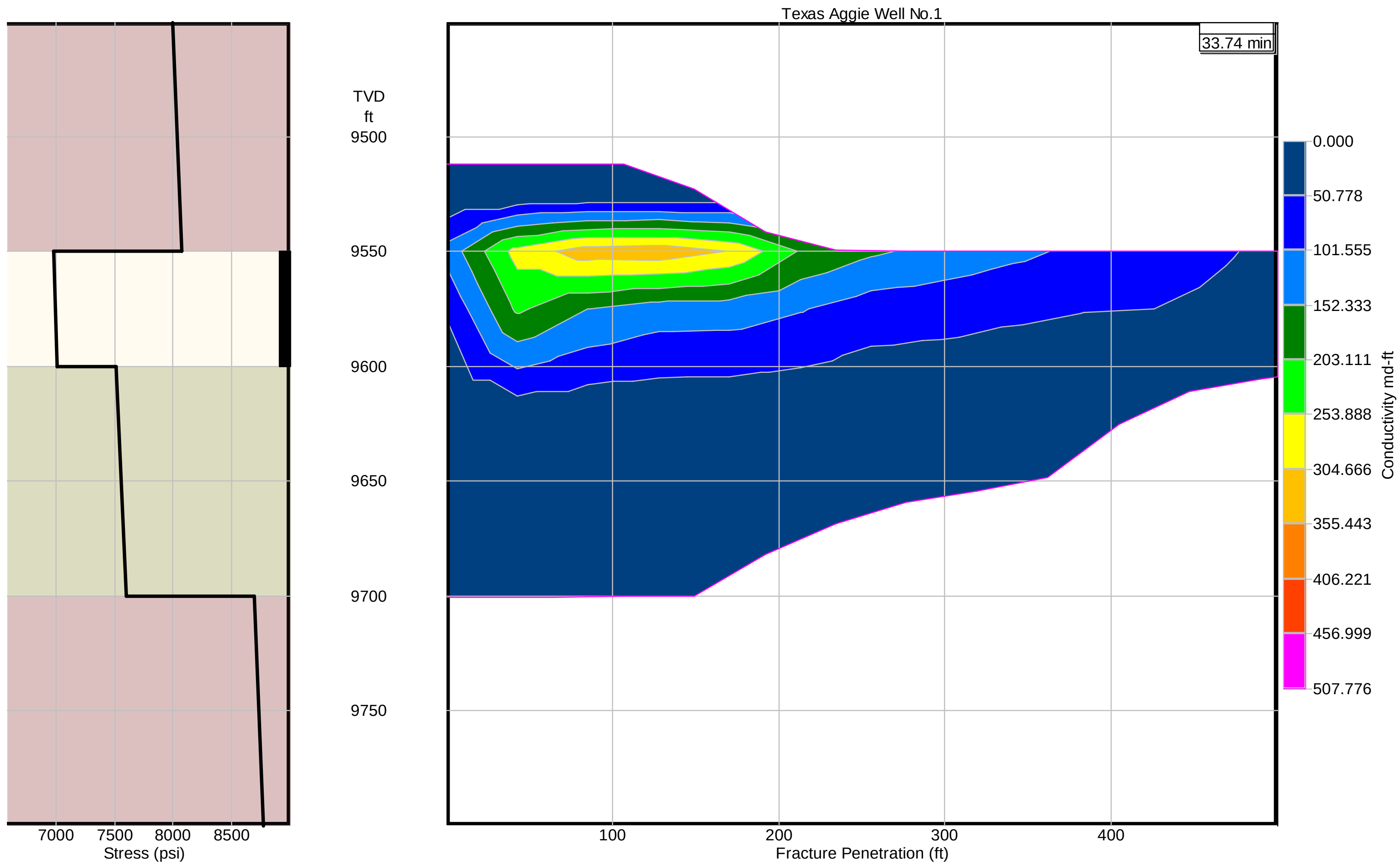

Figure 49: Conductivity Contour Plot for Situation 4 (Hybrid Fracture Treatments)

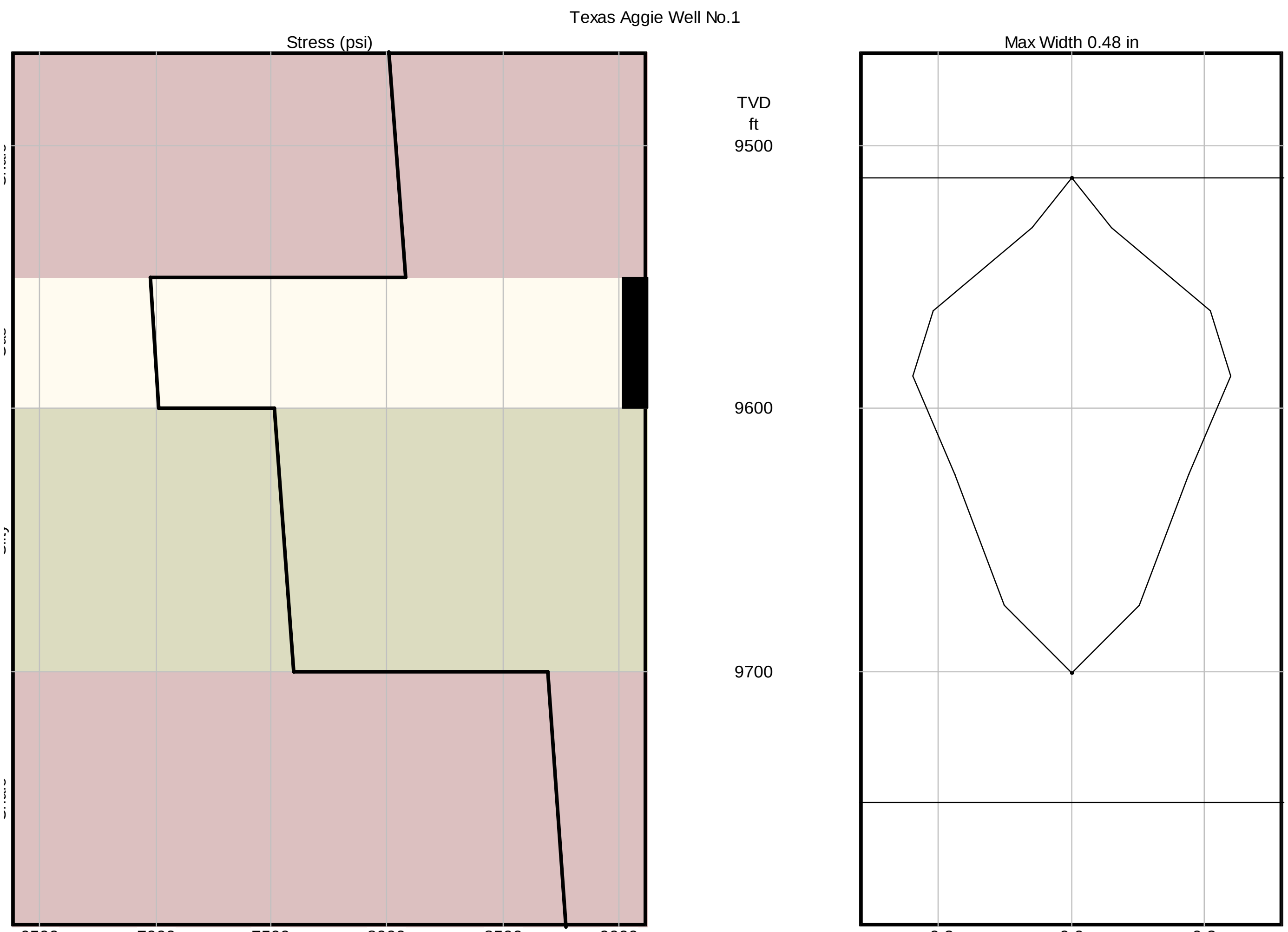

Figure 50: Width Profile for Situation 4 (Hybrid Fracture Treatments)

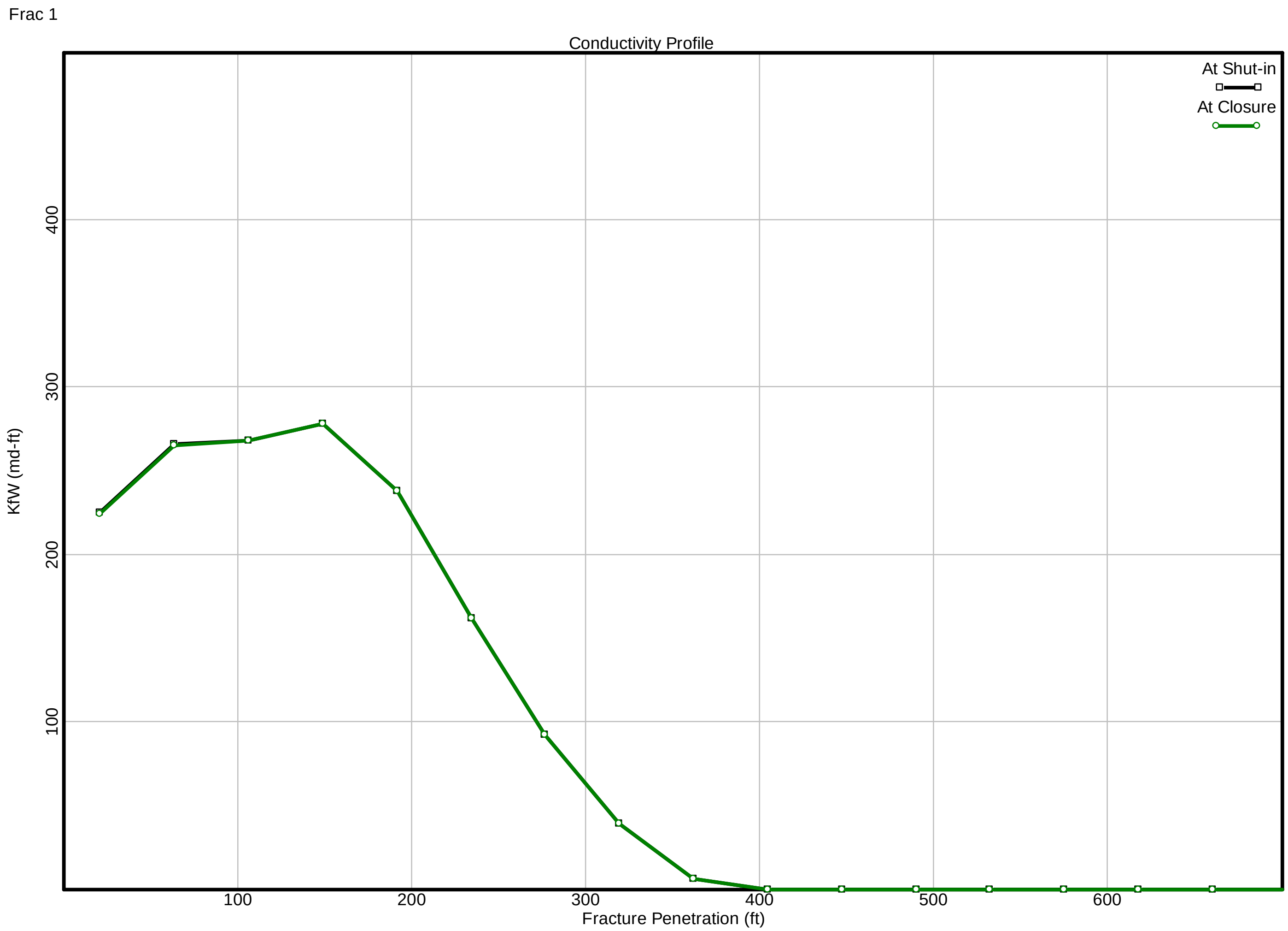

Figure 51: Conductivity Profile for Situation 4 (Hybrid Fracture Treatments)

Experts' Opinion

The results of the survey indicate that almost all the experts consider all the 21 factors listed before designing a fracture treatment. But the most important factors are as follows: 1) bottomhole temperature, 2) reservoir pressure gradient, 3) formation permeability, 4) presence of natural fractures, 5) type of barriers above and below the target zone, 6) formation modulus, and 7) desired fracture half-length and conductivity.

Limited Entry Fracturing

Limited entry fracturing may be used when separate fractures need to be created in thin pay zones separated by thick shales, when it is desired to increase velocities in the near wellbore area to limit early job abnormal pressure responses, when permeability is very low and convergence will not be a problem, or when water fracture treatments in many small fluvial sands are stimulated.

Single Stage Fracturing

Single stage fracturing may be used when a single fracture will communicate with the entire interval, if the total gross interval to be stimulated is less than 20 ft, when permeability is higher and good connectivity to the wellbore is required, or if the zone is not very laminated.

Multi-Stage Fracturing

Multistage fracturing may be used when multiple zones are over 300 ft apart, when the stress contrast between the zones is greater than 1000 psi and the net pressure contrast is not likely to overcome this stress contrast.

Flowchart: Tight Gas Well Fracture Fluid Selection

Fig. 52 shows a flow chart for selection of the appropriate fracture fluid for a particular set of conditions. The flow chart includes eight key parameters to guide engineers to the appropriate fluid. The eight key parameters includes bottomhole temperature, bottomhole pressure, presence of natural fractures, type of lower and upper barrier, modulus of the formation, height of the pay, and desired fracture half-length.

The description of fluids used in chart is as follows:

1) Cross-linked Gel: This fluid is created by using water gelled with polymers that could be cross-linked. So that large volumes of propping agents at high concentrations (8-10 ppg) were commonly pumped.

2) Low Concentration Cross-linked Gel: This fluid is created by using water gelled with low concentration polymers (20# - 25# per 1000 gals of fluid) that could be cross-linked.

3) Gelled Water: This fluid is created by using low viscosity fracturing fluid composed of water gelled with linear polymers, clay stabilizers, surfactants, and friction reducer.

4) Hybrid Fracture Treatment Fluid: The gelled water is pumped as pad followed by cross-linked gel with proppant.

5) Miceller Fluid: Miceller fluid is created by adding an electrolyte, such as quaternary ammonium salt, to water along with a special surfactant which creates long, worm like micelles. The micelles create viscosity in a similar way to have long-chain polymers create viscosity in gel fluids. In this case, hydrocarbons (oil or gas) are the breaker system, so when we produce hydrocarbons it breaks the micelles and help clean up.

6) Foam Fluids: Nitrogen foam is 65 % foam quality or higher. At lower temperatures, 200 ^{0}F or less and for low reservoir pressures, the industry typically uses foam fluids. Foam fluids will break and clean-up when the bottomhole pressure is reduced during flow back.

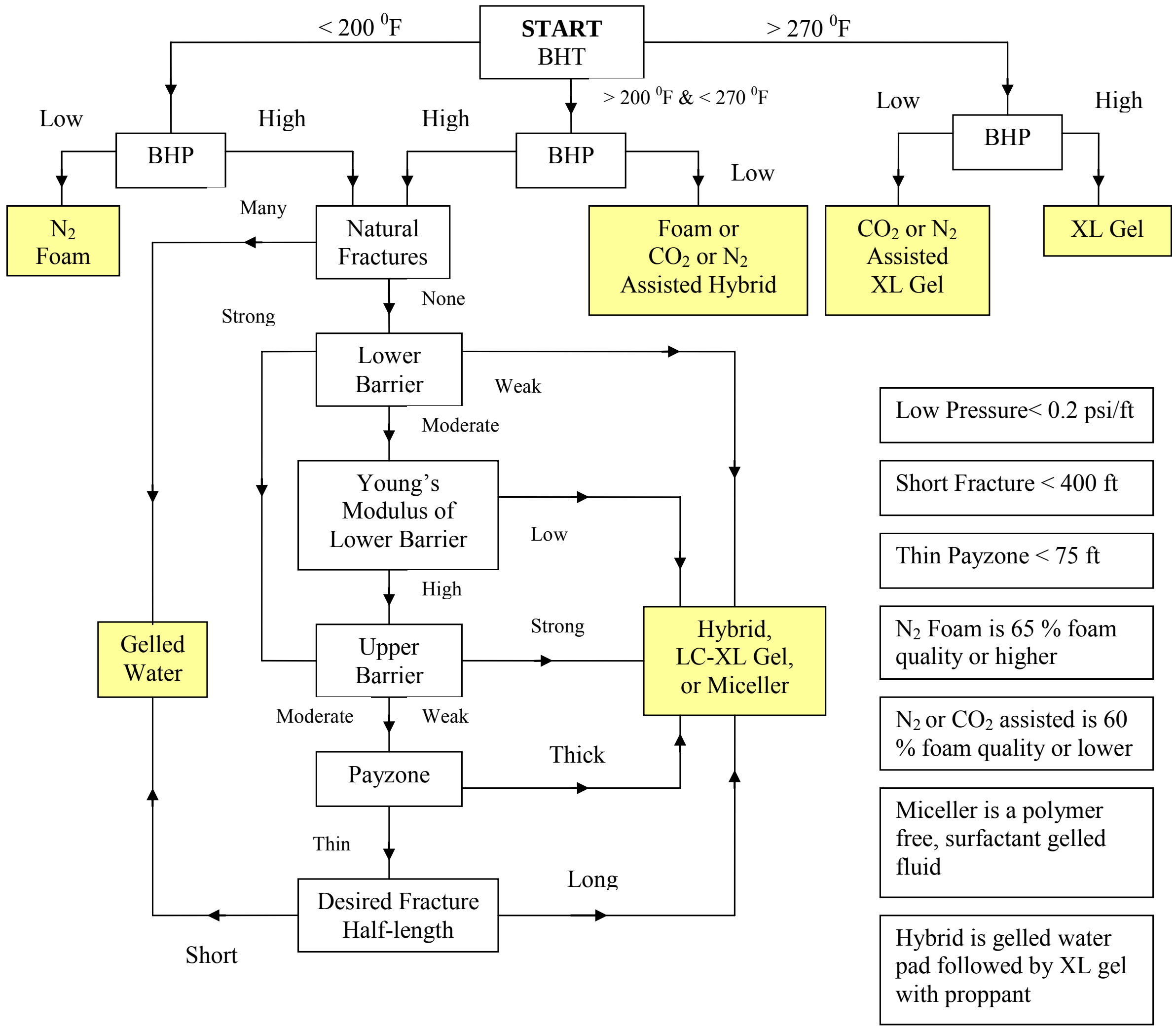

Figure 52: Flowchart for Tight Gas Sand Fracture Fluid Selection

Water Fracture Treatments: A User's Guide

Fig. 52 shows the flow chart for selection of the appropriate fracture fluid. The flow chart includes eight key parameters to guide engineers to the appropriate fracture fluid. When we have low temperature (< 200^0F) and low reservoir pressure gradient (< 0.2 psi/ft) then nitrogen foam treatments work well.

When we have deep and hot (BHT > 270 ^{0}F) wells such as Vicksburg sands and Wilcox-Lobo sands in South Texas where polymers break down rapidly and stabilizing the gel is necessary, we go with the cross-linked gel treatments. When we have high temperature and high reservoir pressure gradient (> 0.2 psi/ft), we should use the cross-linked gel fracture treatment. When we have high temperature and low reservoir pressure gradient (< 0.2 psi/ft) then we should use either carbon dioxide assisted cross-linked gel fracture treatments or nitrogen assisted cross-linked gel fracture treatments.

When we have medium temperature (200 ^{0}F < BHT < 270 ^{0}F) and low reservoir pressure gradient (<0.2 psi/ft) then either carbon dioxide assisted hybrid fracture treatment or nitrogen assisted hybrid fracture treatment should be pumped.

When we could pump water fracture treatments:

1. When we have many pre-existing natural fractures in the formation such as Austin Chalk naturally fractured oil reservoir where the water cleans out fracture and imbibes in the rock and expels oil. The Barnett shale is another naturally fractured reservoir where

water fracture treatments work well by creating a wide fracture network. For the following situation,

- temperature less than 270 ^{0}F,
- high reservoir pressure gradient (>0.2 psi/ft), and
- naturally fractured reservoir

Then, as shown in Fig. 52, we could use water fracture treatment.

2. For the following situation,

- few to none natural fractures,
- temperature less than 270 ^{0}F,
- high reservoir pressure gradient (>0.2 psi/ft),
- strong lower barrier,
- weak or moderate upper barrier,
- thin pay zone (< 75 ft), and
- desired fracture length is less than 400 ft

Then, as shown in Fig. 52, we could use water fracture treatment.

3. For the following situation,

- few to none natural fractures,
- temperature less than 270 ^{0}F,
- high reservoir pressure gradient (>0.2 psi/ft),
- moderate lower barrier with high Young's modulus,
- weak or moderate upper barrier,

- thin pay zone (< 75 ft), and
- desired fracture length is less than 400 ft

Then, as shown in Fig. 52, we could use water fracture treatment.

When water fracture treatments should not be pumped:

1. When we have temperature more than 270 ^{0}F, then cross-linked gel fracture treatments should be used to provide adequate proppant transport.

2. When we have low reservoir pressure gradient (<0.2 psi/ft) at any temperature, then foam or gas assisted system should be used.

3. For the following situation,

- few to none natural fractures,
- temperature less than 270 ^{0}F,
- high reservoir pressure gradient (>0.2 psi/ft), and
- weak lower barrier

Then, all the proppant will settle down in the zone below as gelled water is not viscous enough to retain and transport proppant deep into the fracture. In this situation, hybrid fracture treatments, low concentration cross-linked gel fracture treatments, or miceller fracture treatments should be used to provide effective stimulation as shown in Fig. 52.

4. For the following situation,

- few to none natural fractures,
- temperature less than 270 ^{0}F,
- high reservoir pressure gradient (>0.2 psi/ft), and
- moderate lower barrier with low Young's modulus

Then, water fracture treatments should not be used as proppant will settle down in the zone below pay. In this situation, hybrid fracture treatments, low concentration cross-linked gel fracture treatments, or miceller fracture treatments should be used to provide effective stimulation as shown in Fig. 52.

5. For the following situation,

- few to none natural fractures,
- temperature less than 270 ^{0}F,
- high reservoir pressure gradient (>0.2 psi/ft),
- strong lower barrier or moderate lower barrier with high Young's modulus,
- thick zone (> 75 ft)

Then, all the proppant will get settle in the lower part of the payzone and the top portion of the pay will not have any proppant. In this situation, hybrid fracture treatments, low concentration cross-linked gel fracture treatments, or miceller fracture treatments should be used to provide effective stimulation as shown in Fig. 52.

6. For the following situation,

- few to none natural fractures,
- temperature less than 270 ^{0}F,
- high reservoir pressure gradient (>0.2 psi/ft),
- strong lower barrier or moderate lower barrier with high Young's modulus,
- thin zone (< 75 ft), and
- strong upper barrier

Then, we will not have enough vertical space and as proppant will settle near the wellbore there is a risk of proppant bridging and possible screen out. In this situation, hybrid fracture treatments, low concentration cross-linked gel fracture treatments, or miceller fracture treatments should be used to provide effective stimulation as shown in Fig. 52.

7. For the following situation,

- few to none natural fractures,
- temperature less than 270 ^{0}F,
- high reservoir pressure gradient (>0.2 psi/ft),
- strong lower barrier or moderate lower barrier with high Young's modulus,
- weak or moderate upper barrier,
- thin pay zone (< 75 ft), and
- desired fracture length is more than 400 ft

Then, water fracture treatments should not be used. In this situation, hybrid fracture treatments or miceller fracture treatments should be used to create long, conductive fracture as shown in Fig. 52.

CHAPTER V

CONCLUSIONS

On the basis of this research, we have following conclusions:

- Evaluation of field data from the wells in the Carthage field that are completed in the Cotton Valley sands suggests that medium proppant concentration treatments produces more gas than low proppant concentration treatments based upon Best 3 months, Best 6 months, Best 12 months, and 3-year cumulative gas production with 95 % statistical confidence.
- History matching gas production from a sample of Cotton Valley wells in Carthage field using an analytical reservoir simulator indicates that medium proppant concentration treatments creates longer effective fracture half-lengths as well as have larger drainage area than low proppant concentration treatments with 95 % statistical confidence.
- The results of production data history matching also suggested that pressure has no effect on values of the effective fracture half-length and drainage area for low proppant concentration treatments while has significant effect for medium proppant concentration treatments.
- A fully 3D fracture propagation model was helpful to determine necessary reservoir conditions for pumping successful water fracture treatments in medium temperature reservoirs like to Cotton Valley sands.
- We have developed a flow chart to help engineers select the appropriate type of fracture fluid for a specific set of reservoir conditions.

- We have developed guidelines on when water fracture treatments should and should not be pumped to stimulate wells.

NOMENCLATURE

k = permeability

kh = permeability-thickness product

Φh = porosity-thickness product

OGIP = Original Gas-in-place

L_f = Fracture Half-length

wk_f = Fracture Conductivity

P_i = Initial Reservoir Pressure

DOFP = Day of First Production

LPC = Low Proppant Concentration

MPC = Medium Proppant Concentration

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APPENDIX A

Let's consider various types of fracture fluids for gas wells:

1. X-linked gel fracture treatments
2. Water fracture treatments
3. Hybrid fracture treatments: Gelled water pad followed by X-linked gel with proppant
4. Foam fracture treatments
5. Miceller fracture treatments: Polymer free, surfactant gelled fluid.
6. Other

   ____

   ____

Check all the factors, you consider when selecting a fracturing fluid and then rank the top five factors in order of importance.

No.	Factors	Check all that apply	Top five
1	Depth of formation		
2	Bottomhole temperature		
3	Bottomhole pressure		
4	Fracture gradient		
5	Net gas pay		
6	Formation permeability		
7	Formation Lithology		
8	Formation porosity		
9	Formation Modulus		
10	Gross fracture height		
11	Number of pay zones		
12	Expected flowrate		
13	Location of well		
14	Cost of fracturing fluid		
15	Well trajectory		
16	Presence of natural fractures		
17	Strong barrier at bottom		
18	Strong barrier at top		
19	Nearby water aquifer		
20	Desired fracture length		
21	Desired fracture conductivity		
22			
23			
24			
25			

1. What ideal combinations and values of your top five parameters are necessary for you to select a fracturing fluid?

I. X-linked Gel Fluid:

No.	Parameter	Minimum	Maximum	Ideal	Units
1					
2					
3					
4					
5					

II. Water Fracture Fluid:

No.	Parameter	Minimum	Maximum	Ideal	Units
1					
2					
3					
4					
5					

III. Hybrid Fracture Fluid:

No.	Parameter	Minimum	Maximum	Ideal	Units
1					
2					
3					
4					
5					

IV. Foam Fracture Fluid:

No.	Parameter	Minimum	Maximum	Ideal	Units
1					
2					
3					
4					
5					

V. Miceller Fracture Fluid:

No.	Parameter	Minimum	Maximum	Ideal	Units
1					
2					
3					
4					
5					

VI. Other ____

No.	Parameter	Minimum	Maximum	Ideal	Units
1					
2					
3					
4					
5					

Please check appropriate option(s).

2. When do you use **limited-entry** fracturing?

______When separate fractures to be created in several hundred feet of thin distant zones

Other: ____

____

____

3. When do you use **single stage** fracturing with clustered perforations?

______When a single fracture will communicate with the entire interval

______If the total gross interval to be stimulated is < __________ ft

Other: ____

____

____

4. When do you consider **multi-stage** fracturing?

______When multiple zones are over ___________ ft apart

Other: ____

____

____

5. How do you determine the amount of **pre-pad** needed for a treatment?

______Pre-pad should be about_________ % of pad.

______Pre-pad is ________ times the volume of the wellbore.

Other: ____

____

____

6. How do you determine the amount of **pad** to be pumped?

______Pad should be about__________ % of total treatment volume.

______The fracture width at the wellbore should be ___________ inch.

Other: ____

____

____

7. How do you determine the **total volume of fracturing fluid** to be pumped?

____

____

____

____

____

____

8. How do you determine the **optimum viscosity** of the fracturing fluid?

_____ Based on formation temperature

_____ Based on surface pump pressure

_____ Based on pipe friction considerations

______ Based on proppant size

______ Based on fluid loss calculations

______ Based on fracture width calculations

______ Based on flowback

Other: ____

____

____

9. How do you determine the **injection rate** (Q)?

______ Maximum based upon maximum allowable surface injection pressure.

______ Optimize to control out of zone fracture growth.

Other: ____

____

____

10. How do you decide upon the **type** of proppant to be pumped?

______ Based on total proppant volume

______ Based on closure pressure

______ Based on targeted fracture conductivity value

______ Based on the cost

Other: ____

____

____

11. How do you determine the **size** of the proppant?

______ Based on viscosity of fracturing fluid

______ Based on type of formation

______ Based on fracture width

______ Based on depth

______ Based on proppant transport

______ Based on required conductivity

Other: ____

____

____

12. Please define your view of what is meant by the following terms for gas wells.

- High pressure gradient > _____________ psi/ft
- Medium pressure gradient < _____________ and > _____________ psi/ft
- Low pressure gradient < _____________ psi/ft
- High reservoir temperature > _____________ ^{0}F
- Medium reservoir temperature < _____________ and > _____________ ^{0}F
- Low reservoir temperature < _____________ ^{0}F
- High permeability > _____________ md
- Low permeability < _____________ md

APPENDIX B

Comparison of Means for Best 12 months gas production

Hypothesis testing for all the wells in group I and group II based upon Best 12 months gas production.

Best 12 Months Gas Production	**Group I**		**Group II**	
	MPC	**LPC**	**MPC**	**LPC**
Mean, Mcf/mo	39850	32650	33235	23940
Standard Deviation	13790	13810	11190	8065
Data Points	83	40	66	46

Testing normality: The Empirical rule was used to test normality of datasets.

Best 12 Months Gas Production	**Group I**		**Group II**	
	MPC	**LPC**	**MPC**	**LPC**
Mean ± 2 Std. Dev.	96 %	95 %	97 %	100 %
Mean ± 3 Std. Dev.	100 %	100 %	100 %	100 %

All datasets qualified the Empirical rule that indicated they were normally distributed.

Null hypothesis: Means are equal for both types of fracture treatments. H_0: $\mu_1 = \mu_2$

Research hypothesis: Means are unequal for both types of fracture treatments. H_1: $\mu_1 \neq \mu_2$

Comparing MPC with LPC:

Parameter	**Values**	
	Group I	**Group II**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.01	0.00

The p-value was less than rejection criterion, α, so we can reject the null hypothesis. This indicates Best 12 months gas production was unequal for MPC and LPC with 95 % significance level. MPC does much better than LPC for both group I and group II wells as shown in Fig. A-2.1 when compared on the basis of Best 12 months gas production.

Fig. A-2.2 is a plot of cumulative density function for Best 12 months gas production for both pressure groups and both fracture treatments.

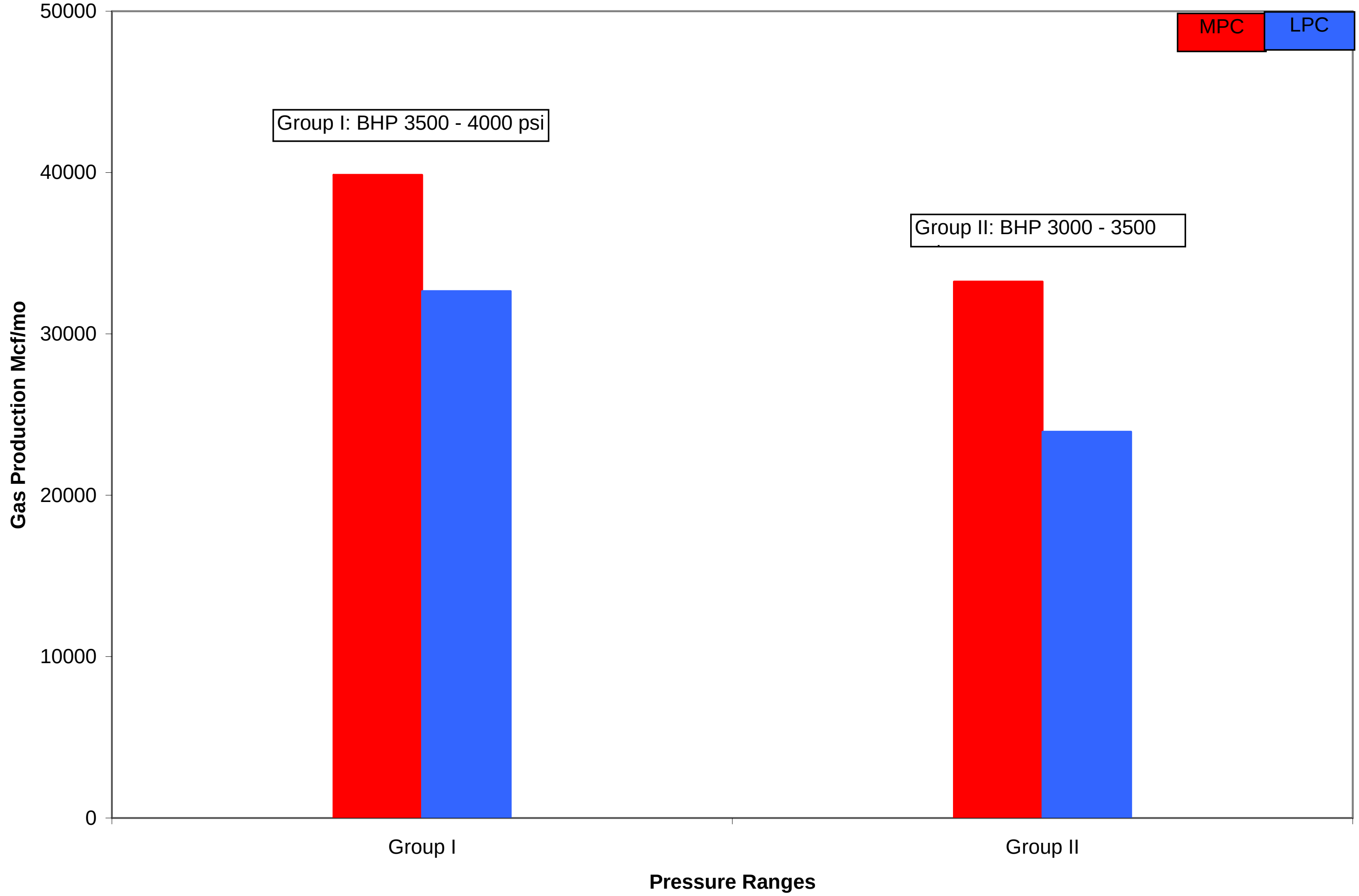

Figure A-2.1: Comparison of Average Best 12 Months Gas Production for Wells in the Carthage Field

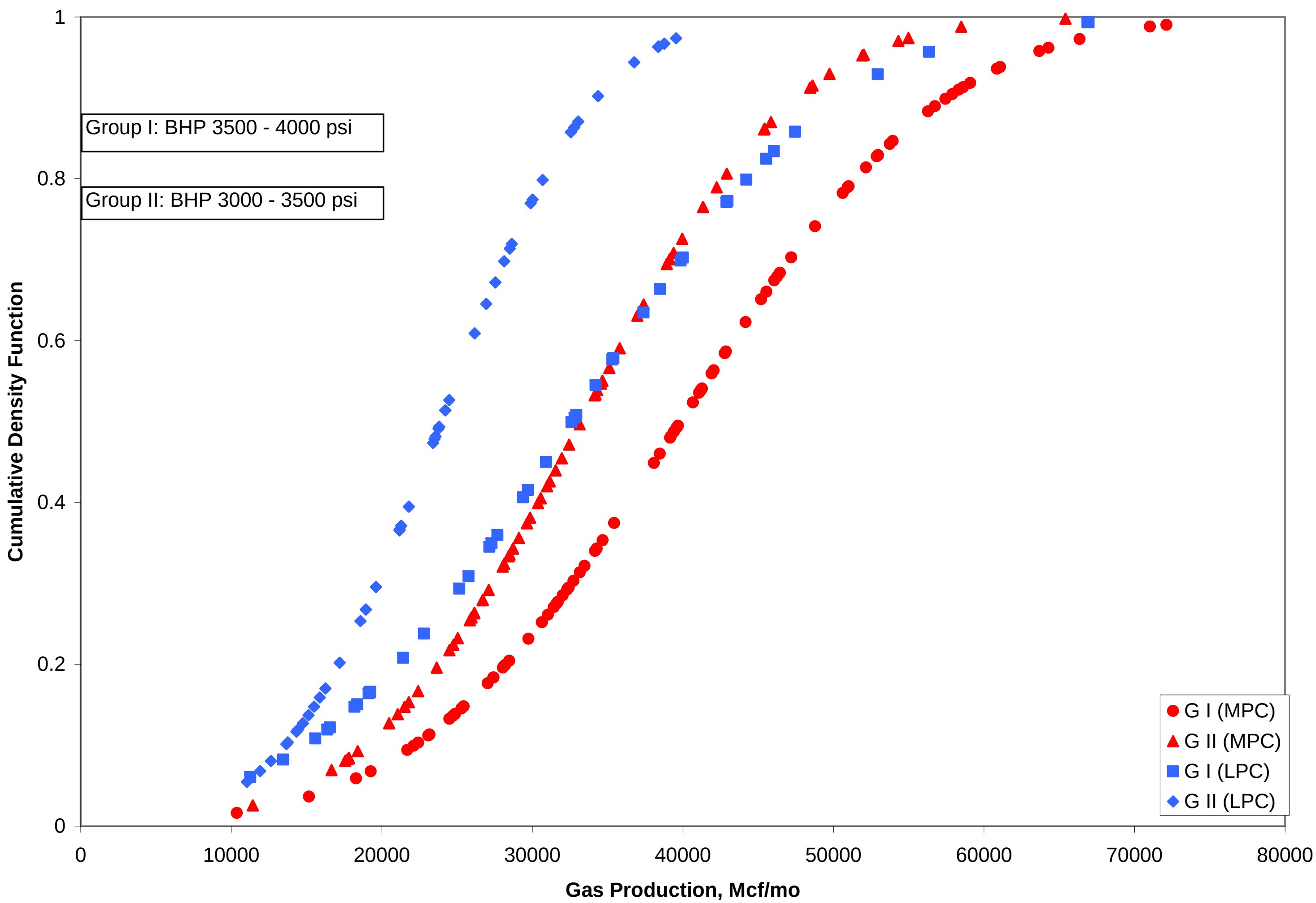

Figure A-2.2: Cumulative Frequency Distribution for Best 12 Months Gas Production for Both Groups and Both Treatments (Carthage)

Comparison of Means for Best 6 months gas production

Hypothesis testing for all the wells in group I and group II based upon Best 6 months gas production.

Best 6 Months Gas Production	**Group I**		**Group II**	
	MPC	**LPC**	**MPC**	**LPC**
Mean, Mcf/mo	47140	39150	40330	28775
Standard Deviation	15690	15090	12920	9380
Data Points	85	41	66	46

Testing normality: The Empirical rule was used to test normality of datasets.

Best 6 Months Gas Production	**Group I**		**Group II**	
	MPC	**LPC**	**MPC**	**LPC**
Mean ± 2 Std. Dev.	97 %	95 %	95 %	100 %
Mean ± 3 Std. Dev.	100 %	100 %	100 %	100 %

All datasets qualified the Empirical rule that indicated they were normally distributed.

Null hypothesis: Means are equal for both types of fracture treatments. H_0: $\mu_1 = \mu_2$

Research hypothesis: Means are unequal for both types of fracture treatments. H_1: $\mu_1 \neq \mu_2$

Comparing MPC with LPC:

Parameter	**Values**	
	Group I	**Group II**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.01	0.00

The p-value was less than rejection criterion, α, so we can reject the null hypothesis. This indicates Best 6 months gas production was unequal for MPC and LPC with 95 % significance level. MPC does much better than LPC for both group I and group II wells as shown in Fig. A-2.3 when compared on the basis of Best 6 months gas production.

Fig. A-2.4 is a plot of cumulative density function for Best 6 months gas production for both pressure groups and both fracture treatments.

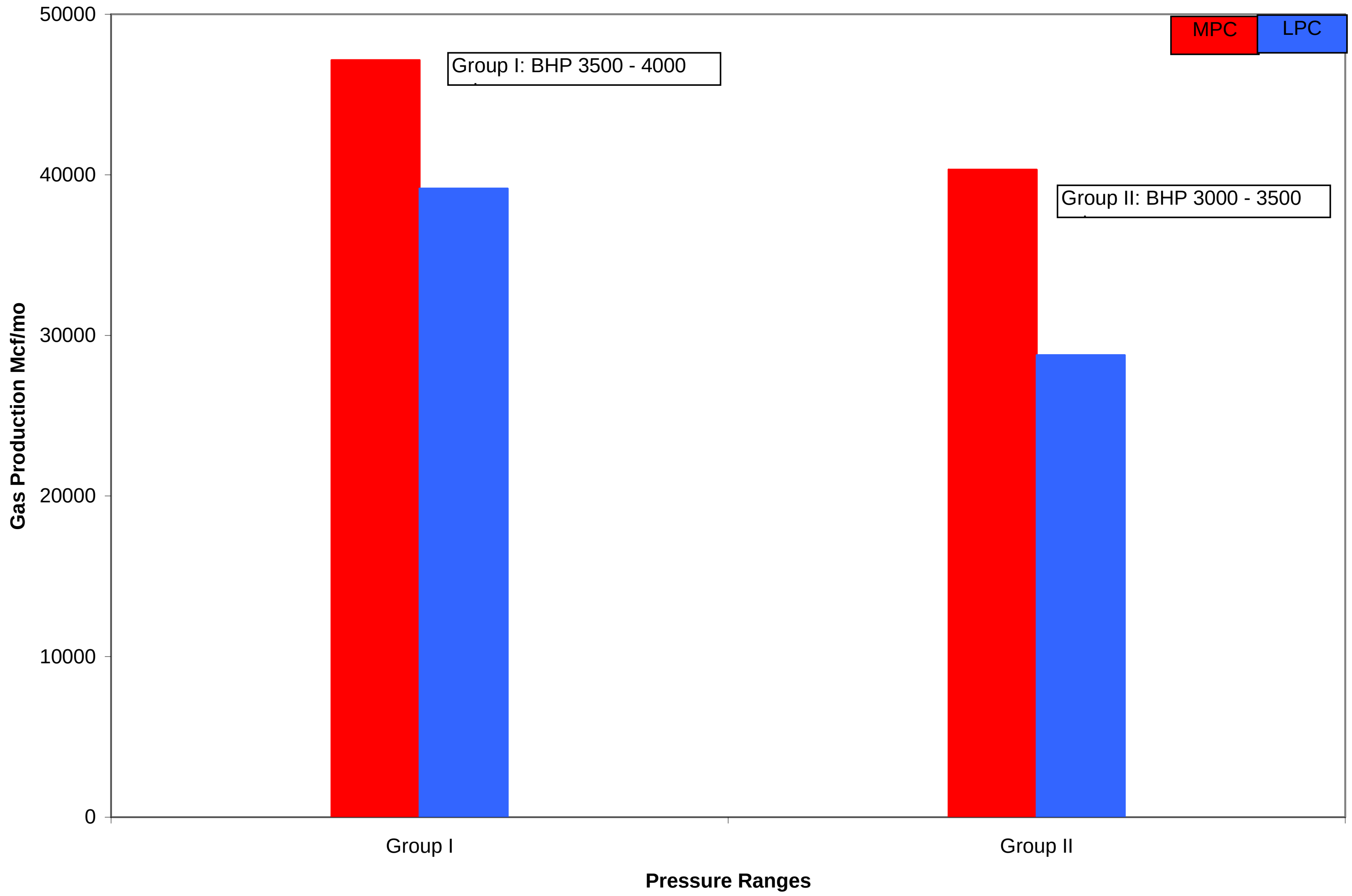

Figure A-2.3: Comparison of Average Best 6 Months Gas Production for Wells in the Carthage Field

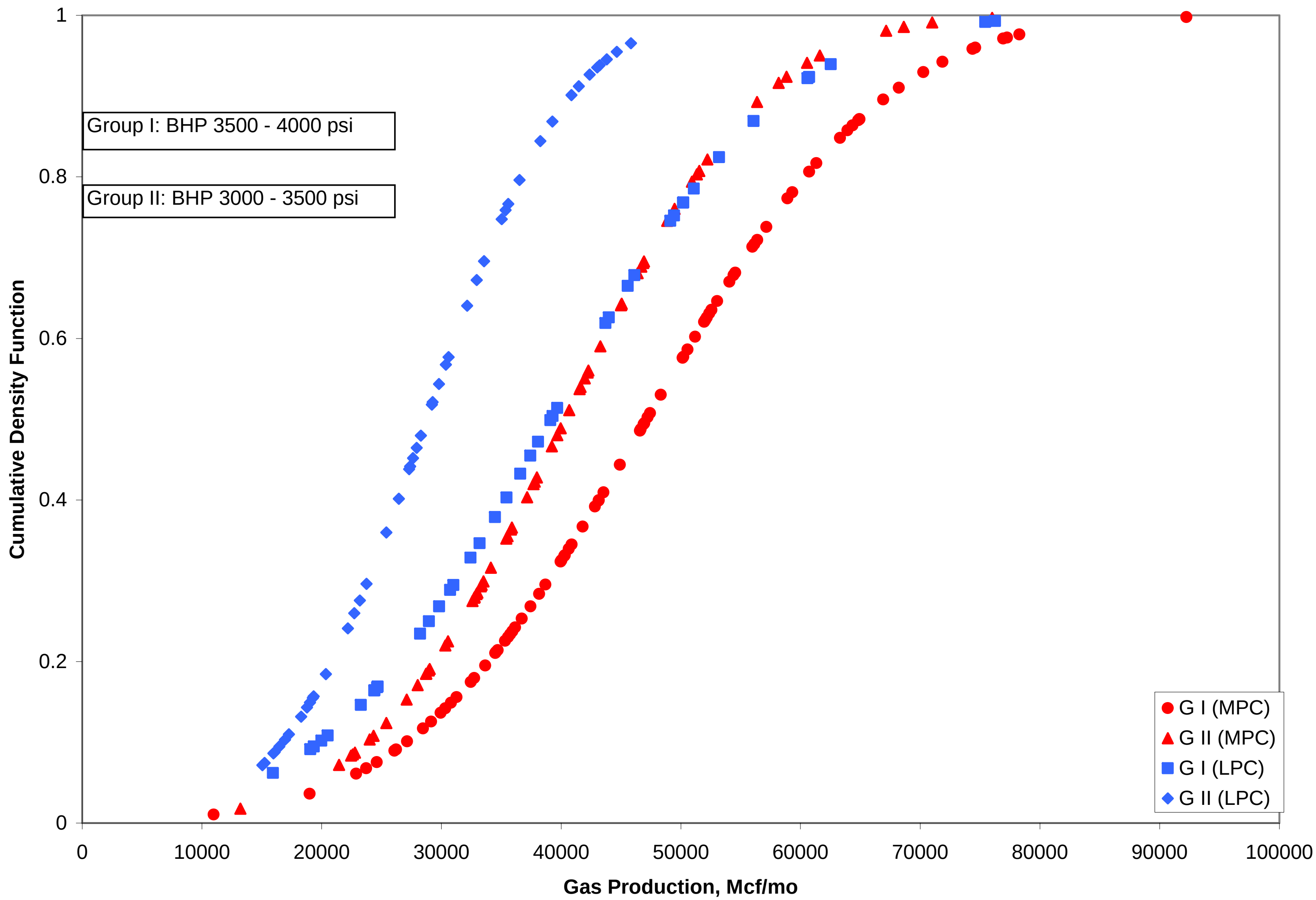

Figure A-2.4: Cumulative Frequency Distribution for Best 6 Months Gas Production for Both Groups and Both Treatments (Carthage)

Comparison of Means for Best 3 months gas production

Hypothesis testing for all the wells in group I and group II based upon Best 3 months gas production.

Best 3 Months Gas Production	**Group I**		**Group II**	
	MPC	**LPC**	**MPC**	**LPC**
Mean, Mcf/mo	53910	43660	46840	33575
Standard Deviation	17265	15300	14445	10850
Data Points	85	41	66	46

Testing normality: The Empirical rule was used to test normality of datasets.

Best 3 Months Gas Production	**Group I**		**Group II**	
	MPC	**LPC**	**MPC**	**LPC**
Mean ± 2 Std. Dev.	95 %	95 %	95 %	98 %
Mean ± 3 Std. Dev.	99 %	100 %	100 %	100 %

All datasets qualified the Empirical rule that indicated they were normally distributed.

Null hypothesis: Means are equal for both types of fracture treatments. H_0: $\mu_1 = \mu_2$

Research hypothesis: Means are unequal for both types of fracture treatments. H_1: $\mu_1 \neq \mu_2$

Comparing MPC with LPC:

Parameter	Values	
	Group I	Group II
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.00	0.00

The p-value was less than rejection criterion, α, so we can reject the null hypothesis. This indicates Best 3 months gas production was unequal for MPC and LPC with 95 % significance level. MPC does much better than LPC for both group I and group II wells as shown in Fig. A-2.5 when compared on the basis of Best 3 months gas production.

Fig. A-2.6 is a plot of cumulative density function for Best 3 months gas production for both pressure groups and both fracture treatments.

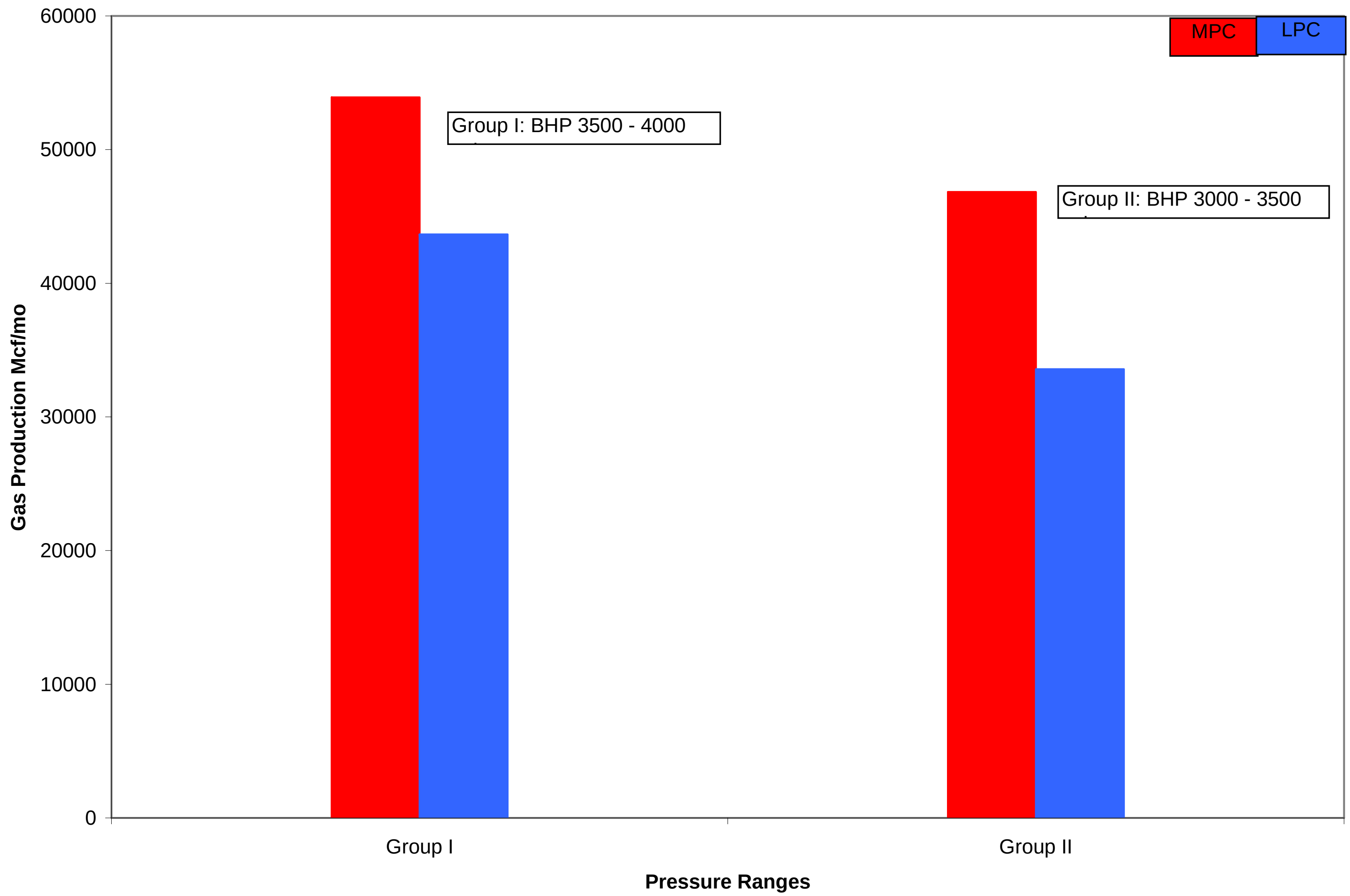

Figure A-2.5: Comparison of Average Best 3 Months Gas Production for Wells in the Carthage Field

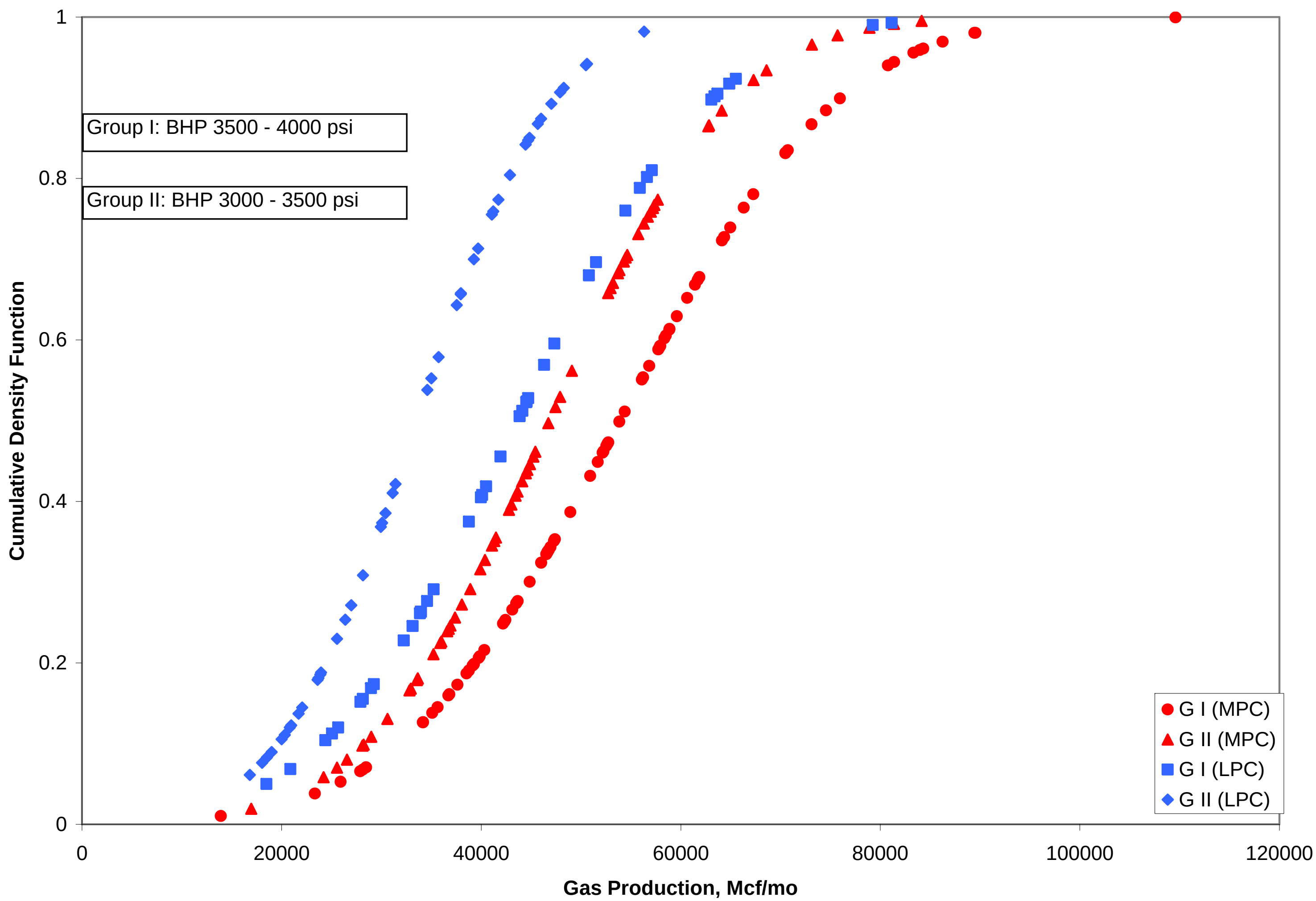

Figure A-2.6: Cumulative Frequency Distribution for Best 3 Months Gas Production for Both Groups and Both Treatments (Carthage)

APPENDIX C

Comparison of Means for estimated effective drainage area

Hypothesis testing for all the wells in group I and group II based upon estimated effective drainage area.

Drainage Area	Group I		Group II	
	MPC	LPC	MPC	LPC
Mean, acres	22	10.5	16.5	10.5
Standard Deviation	12.5	4	6	4
Data Points	29	12	10	12

Testing normality: The Empirical rule was used to test normality of datasets.

Drainage Area	Group I		Group II	
	MPC	LPC	MPC	LPC
Mean ± 2 Std. Dev.	96 %	95 %	95 %	100 %
Mean ± 3 Std. Dev.	100 %	100 %	100 %	100 %

All datasets qualified the Empirical rule that indicated they were normally distributed.

Null hypothesis: Means are equal for both types of fracture treatments. H_0: $\mu_1 = \mu_2$

Research hypothesis: Means are unequal for both types of fracture treatments. H_1: $\mu_1 \neq \mu_2$

Comparing MPC with LPC:

Parameter	**Values**	
	Group I	**Group II**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.00	0.01

The p-value was less than rejection criterion, α, so we can reject the null hypothesis. This indicates estimated effective drainage area was unequal for MPC and LPC with 95 % significance level. MPC does much better than LPC for both group I and group II wells as shown in Fig. A-3.1 when compared on the basis of estimated effective drainage area.

Fig. A-3.2 is a plot of cumulative density function for estimated effective drainage area for both pressure groups and both fracture treatments.

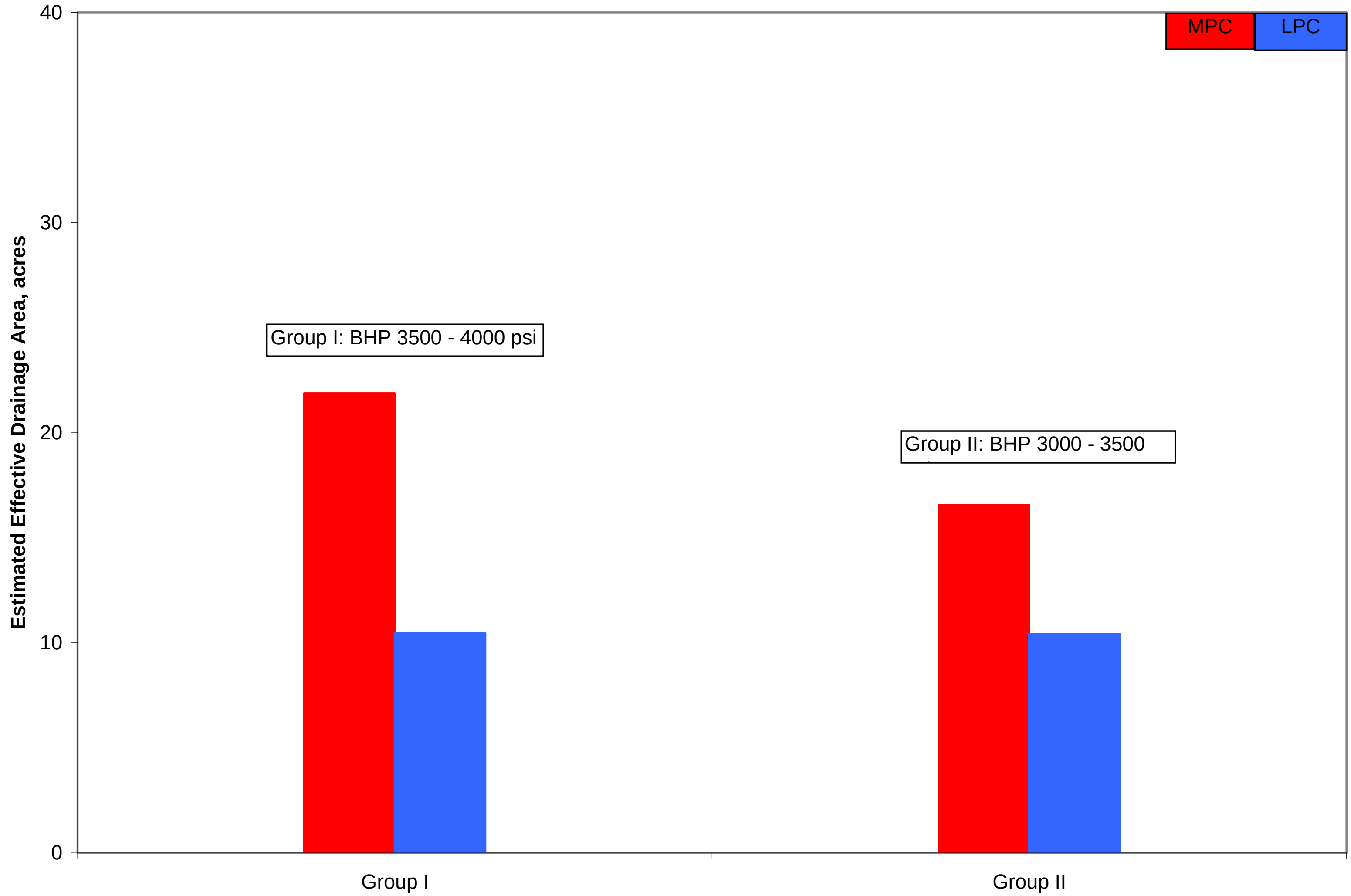

Figure A-3.1: Comparison of Average Estimated Effective Drainage Area for Wells in the Carthage Field

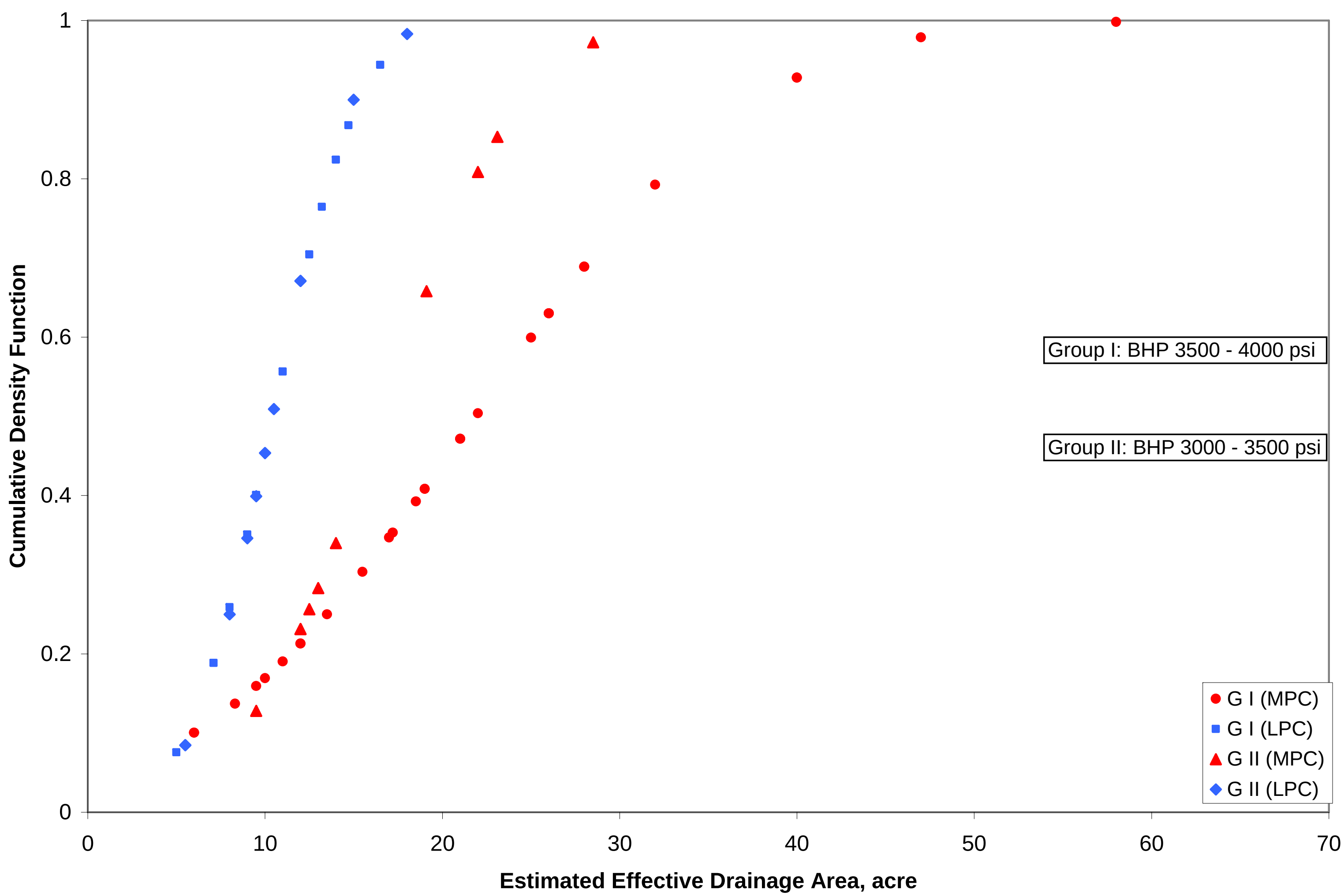

Figure A-3.2: Cumulative Frequency Distribution for Estimated Effective Drainage Area for Both Groups and Both Treatments

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