EVALUATION OF FRACTURE TREATMENT TYPE ON THE RECOVERY OF GAS FROM THE COTTON VALLEY FORMATION

A Thesis

by

RAMAKRISHNA YALAVARTHI

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 2008

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Stephen A. Holditch
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December 2008

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ABSTRACT

Evaluation of Fracture Treatment Type on the Recovery of Gas from the Cotton Valley Formation. (December 2008)

Ramakrishna Yalavarthi, B.Tech., Indian School of Mines University

Chair of Advisory Committee: Dr. Stephen A. Holditch

Every tight gas well needs to be stimulated with a hydraulic fracture treatment to produce natural gas at economic flow rates and recover a volume of gas that provides an acceptable return on investment. Over the past few decades, many different types of fracture fluids, propping agents and treatment sizes have been tried in the Cotton Valley formation. The treatment design engineer has to choose the optimum fluid, optimum proppant, optimum treatment size and make sure the optimum treatment is mixed and pumped in the field. These optimum values also depend on drilling costs, fracturing costs and other economic parameters; such as gas prices, operating costs and taxes. Using information from the petroleum literature, numerical and analytical simulators, and statistical analysis of production data, this research provides a detailed economic evaluation of the Cotton Valley wells drilled in the Elm Grove field operated by Matador Resources to determine not only the optimum treatment type, but also the optimum treatment volume as a function of drilling costs, completion costs, operating costs and gas prices. This work also provides an evaluation of well performance as a function of the fracture treatment type by reviewing production data from the Carthage and Oak Hill Cotton Valley fields in Texas and the Elm Grove field in Louisiana.

DEDICATION

This thesis is dedicated to my parents, who are my inspiration as I pursue becoming an engineer. They are examples to me of wisdom, integrity and character. I also dedicate my work to my sister. They have endured my absence and always supported me at difficult crossroads. I love you all.

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. Stephen Holditch for his guidance and support throughout the course of this research. I would also like to thank Neil Barman, Brad Robinson, Mike Ernest, Ryan London, Tatiana Kliem with Matador Resources Inc.; Autum Gerlach with TRC Consultants L.C., and my advisory committee for their help and support in completing this project.

Thanks also go to my friends and colleagues and the department faculty and staff for making my time at Texas A&M University a great experience. Finally, thanks to my family for their encouragement and love.

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CHAPTER I

INTRODUCTION

1.1 U.S. Natural Gas Scenario

The energy demand in U.S. continues to increase during the 21st century. **Fig. 1.1** shows that the natural gas consumption growth in 2007 has been the highest since 1997. The demand for natural gas in the future years is going to continue increasing. The natural gas price has also been increasing as supply and demand tighten. In mid-2008, the price is $8 /MMBtu and is expected to increase as shown in **Fig. 1.2.**

Natural gas is produced from both conventional and unconventional reservoirs. Production from conventional, high permeability reservoirs does not require the use of advanced technology to be economic. Conventional reservoirs are high quality and medium quality formations with permeability greater than 1-10 mD. However, production from unconventional reservoirs does require the use of new technology to produce gas at economic flow rates. Unconventional reservoirs include tight gas sands, tight gas shales, gas hydrates, and coal bed methane. Tight gas sands in the U.S. are those whose expected value of permeability to gas is 0.1 mD or less.

According to the concept of resource triangle, shown in **Fig. 1.3,** all natural resources are distributed log normally in nature. The concept was identified by Masters (1979). Masters

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

suggests that the best or highest-grade deposits are small in size and once found are easy to extract. However, the low-grade deposits are larger in quantity but more difficult to extract because of very low gas permeability. Production from such reservoirs is possible only at high natural gas prices and when the best technology is used to drill, complete and stimulate the well. Since gas prices have been increasing in the past few decades and are expected to remain high; gas production from unconventional reservoirs has become more economic in the past few decades and many such reservoirs are now under development in North America.

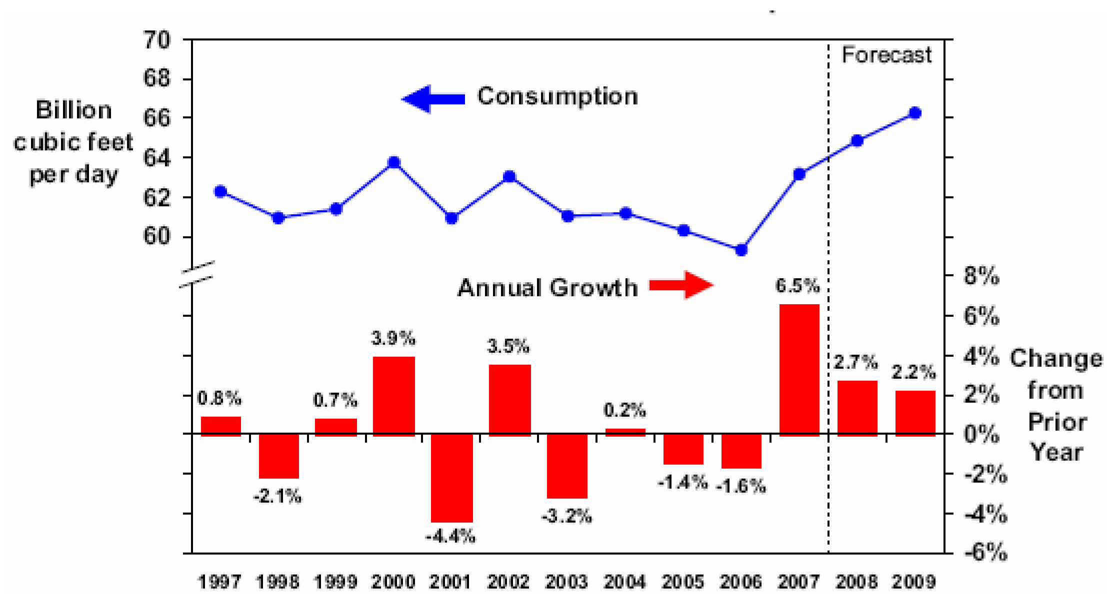
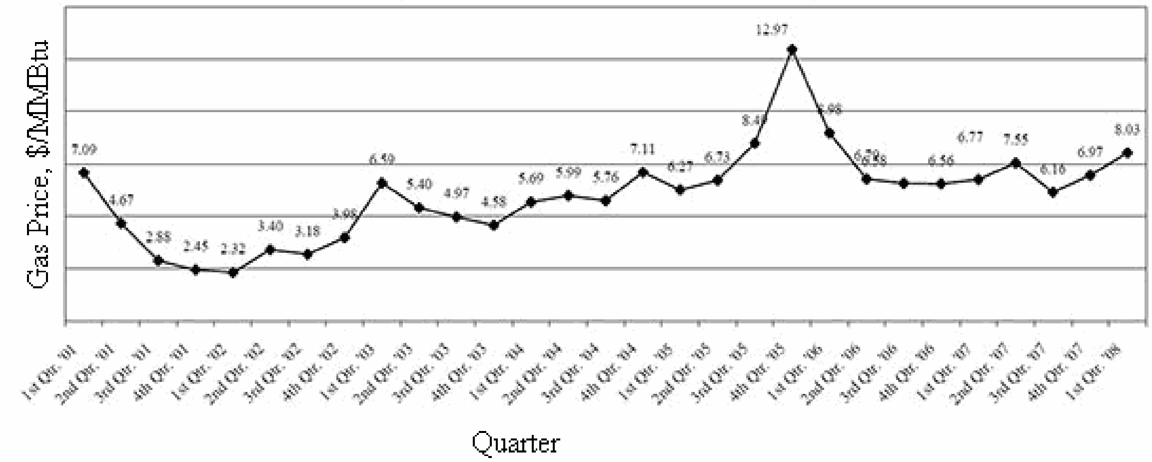


Figure 1.1—U.S. Total Natural Gas Consumption. (Short-Term Energy Outlook 2008)



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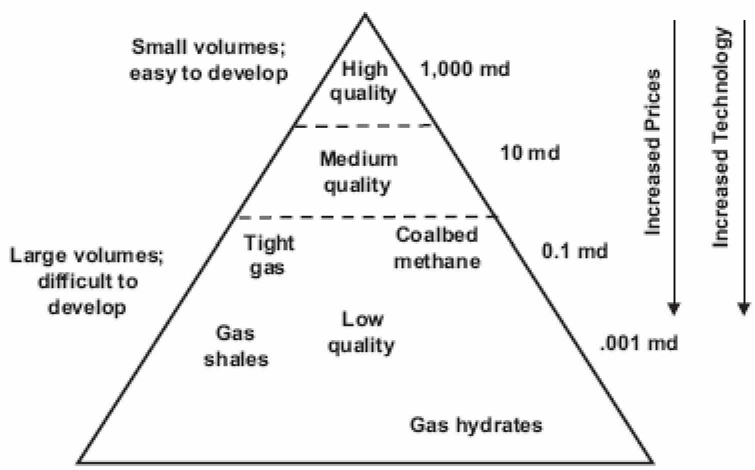


Figure 1.3—Resource Triangle for Natural Gas. (Holditch, 2006)

U.S. natural gas consumption ranged between 22 and 23 Tcf per year form 1995 through 2006 and essentially resembles an undulating plateau. U.S. gas production also reached a similar plateau, ranging from 56.04 billion cubic feet per day (Bcf/d) in 1995 to a high of 58.35 Bcf/d in 2001 before dipping to 53.9Bcf/d in 2006 as shown in **Fig. 1.4**. We can also see that there is a substantial change in U.S. gas productivity over the past decade where the emphasis shifted from conventional onshore and offshore Gulf of Mexico gas to onshore unconventional reservoirs. Gas production over the period of 1995 to 2006 resembles an undulating plateau and decreased after 2001 even though gas well completions doubled from 12,600 wells in 1999 to 27,000 wells in 2006. After 2001 substantial increase in low volume unconventional wells were unable to offset declines in offshore Gulf of Mexico and onshore conventional gas production. Increased drilling boosted unconventional gas production from 4.62 Tcf in 1995 to 11.3 Tcf in 2006 but was not sufficient to offset the declines in conventional gas production (Fig. 1.4). Over this same period conventional offshore gas production declined by 5.02 Tcf per year and onshore conventional gas declined by an additional 3.5 Tcf per year. Thus, net U.S. gas production lost 1.84 Tcf of annual gas production in spite of three-fold increase in gas drilling. (Stark *et al*., 2007)

New technologies, such as multilateral and pinnate horizontal wells and multi-staged hydraulic fracturing treatments, have enabled economic production from many tight formations. Production form unconventional reservoirs using new technology has increased significantly during the past 10 years. Current unconventional gas production rates due to new technology are 1 Tcf/year and are expected to increase to 2.5 Tcf/year

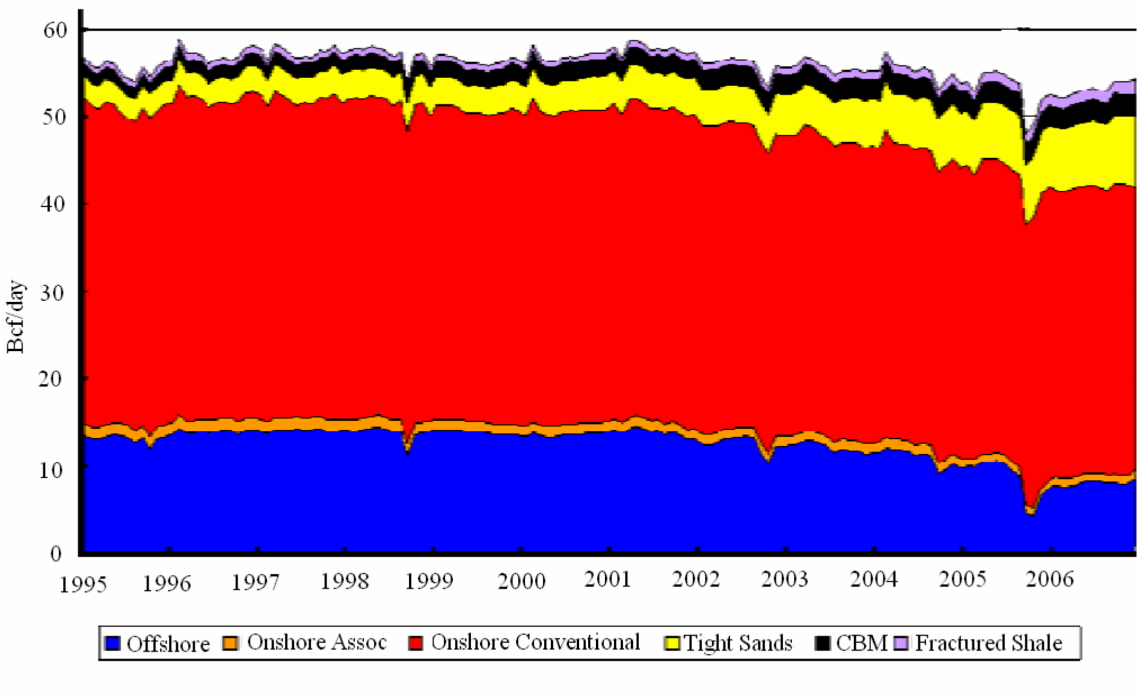


Figure 1.4—U.S. Natural Gas Production by Reservoir. (Stark *et al*, 2007)

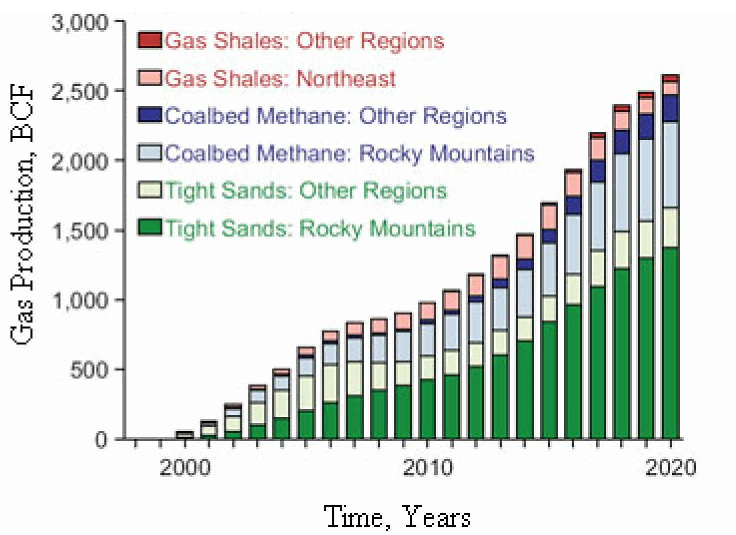


Figure 1.5—Projected Gas Production from Unconventional Resources Due to New Technology. (Impact of Unconventional Gas Technology, 2008)

by the end of 2020 as shown in **Fig. 1.5**. With the help of new technology we hope to compensate for the lost production in the coming years.

1.2 Importance of Tight Gas Sands

The Energy Information Administration (EIA) made predictions of the U.S. gas consumption growth to 2025 in **Fig 1.6**. This graph estimates that the United States total energy consumption by 2025 would be around 140,000 Trillion British Thermal Units, and natural gas will account for 26% of U.S. total energy consumption. Natural gas consumption is expected to increase to over 30 Tcf/year in the next 20 years. This is almost a 40% increase over this period from current levels. (Schubarth *et al*, 2005)

In 1995 natural gas production from onshore and offshore conventional reservoirs in was 51Bcf/day, in 2005 it had declined to 46 Bcf/day. Thus, the net U.S. gas production lost 8.52 Tcf of annual gas production and it is expected to continue decreasing in the absence of new discoveries. In 2001, total natural gas production was 22 Tcf, 27% of this natural gas production came from unconventional reservoirs and this number has been increasing ever since. (Stark *et al*., 2007)

The ultimate recoverable unconventional gas resources in the U.S. are estimated to be about 750 Tcf of which 480 Tcf are in tight sand, 170 Tcf are in coalbeds, and 100 Tcf are in shale. Hence, tight gas sands account for majority of the unconventional gas production. Also, technology improvement in tight gas sands will further improve production form unconventional resources as shown in Figure 1.4.

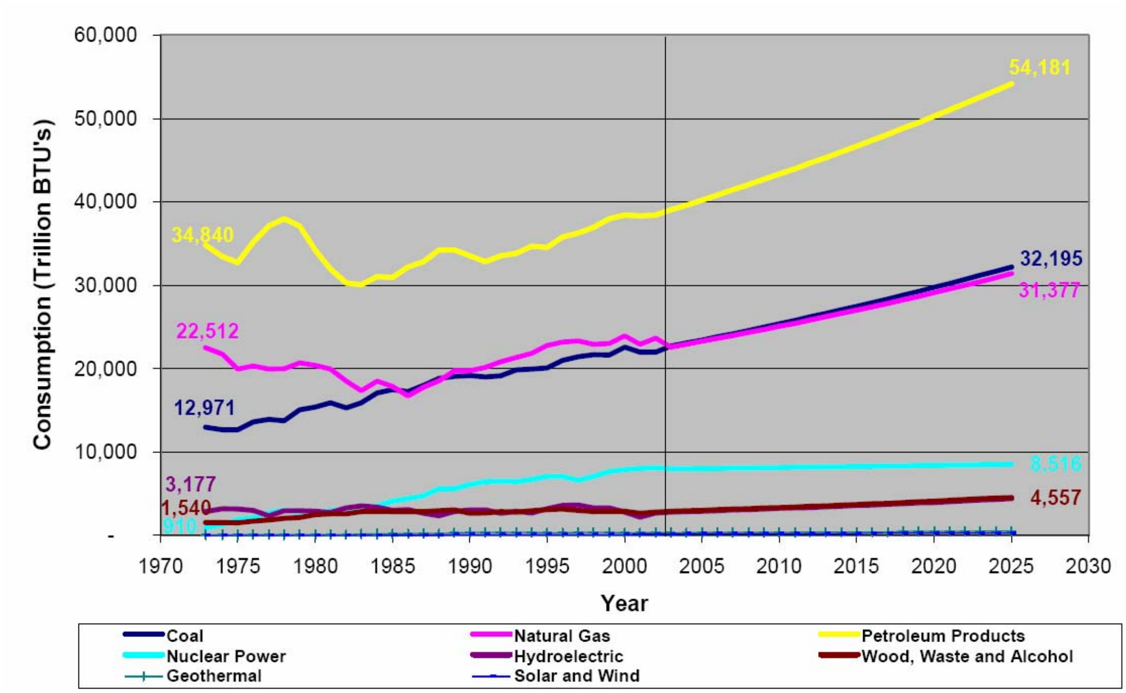


Figure 1.6—Estimated Future U.S. Energy Consumption. (Schubarth *et al*, 2005)

In 1978, the U.S. government defined a tight gas reservoir as one in which the expected value of permeability to gas flow would be less than 0.1 mD. Later, Naik (2005) defined it as a gas bearing sandstone or carbonate matrix which exhibits in-situ permeability to gas of less than 0.1 mD to 0.001 mD. Holditch (2006) defined tight gas as "a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by large hydraulic fracture treatment or produce by use of a horizontal wellbore or multilateral wellbores."

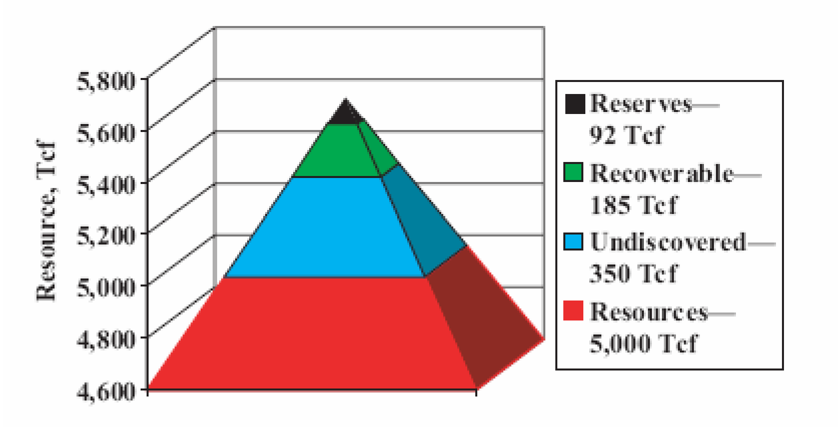


Figure 1.7—Resource Triangle for Tight Gas in the U.S. (Holditch, 2006)

The Gas Technology Institute (GTI) has made estimates of gas production, reserves and potential from the tight gas basins in the U.S. Their estimates for the year 2000 are shown in **Fig. 1.7**. This resource triangle shows that in the year 2000, the U.S. had 92 Trillion cubic feet (Tcf) of tight gas reserves; 185 Tcf of technically recoverable gas; 350 Tcf of undiscovered gas and 5000 Tcf of gas resources. Technically recoverable gas is known to exist, but the wells have not yet been drilled; undiscovered gas is the gas that is likely to be discovered in known tight gas basins, and the gas resources category represents the gas in place in the U.S. tight gas basins. There would need to be substantial improvements in technology and high gas prices to produce economically any of the gas in the Resource category. GTI in 2001 estimated that 20% of the total gas production of U.S. comes from tight gas reservoirs.

There are 15 major tight gas basins in the U.S. as shown in **Fig. 1.8.** Holditch (1991) suggest that that the tight gas formations are heterogeneous in nature consisting of sandstone, siltstone, and shale dispersed vertically and horizontally throughout the formation. The layers of sandstone, siltstone, and shale present a high contrast in permeability, porosity, and gas saturation depending on the depositional activities.

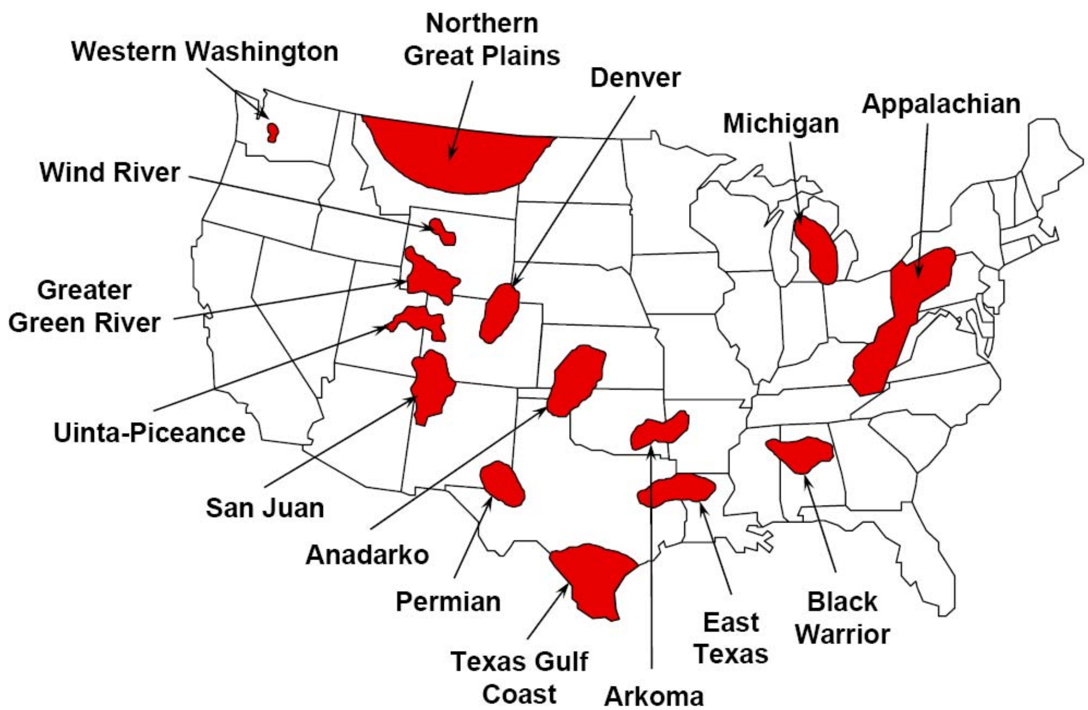


Figure 1.8—Major U.S. Tight Gas Sand Basins. (GRI)

1.3 Irregularity in Cotton Valley Tight Gas Sandstones

In this research, we have analyzed data from the Cotton Valley formation in the East Texas basin, which straddles the border of Texas and Louisiana. Wescott (1983) studied the diagenesis of the Cotton Valley Tight Gas Sands and suggested that low reservoir quality of these sands is due to the complex process of compaction, cementation, dissolution and replacement. He suggested that the Cotton Valley sandstones can be classified into three groups; Type-I rocks are poor reservoir rocks because they are tightly cemented early in the diagenetic history by quartz overgrowths and calcites. Type-II rocks are better reservoir rocks although they have clay-rich sands with poor initial porosities and permabilities because the clay prohibits nucleation of silica overgrowths. Type-III rocks are high in unstable grains and have good secondary porosity produced by the dissolution of grains and cements; and hence have the highest measured porosities in the Cotton Valley sandstones and are of relatively good reservoir quality.

In our study we will be able to show this kind of irregularity of permeability in different regions of the same field of Cotton Valley sands. We will be able to clearly see the permeability difference of the various regions.

1.4 Hydraulic Fracturing Overview

Hydraulic fracturing involves the injection of special fluids into the formation. As the injection rate increases, the pressure in the wellbore also increases. As we continue pumping, we eventually increase the well bore pressure until it exceeds the formation fracture pressure and the rock physically splits and forms a fracture. As fluid is pumped down the fracture, it pushes the earth apart and the fracture propagates away form the well bore.

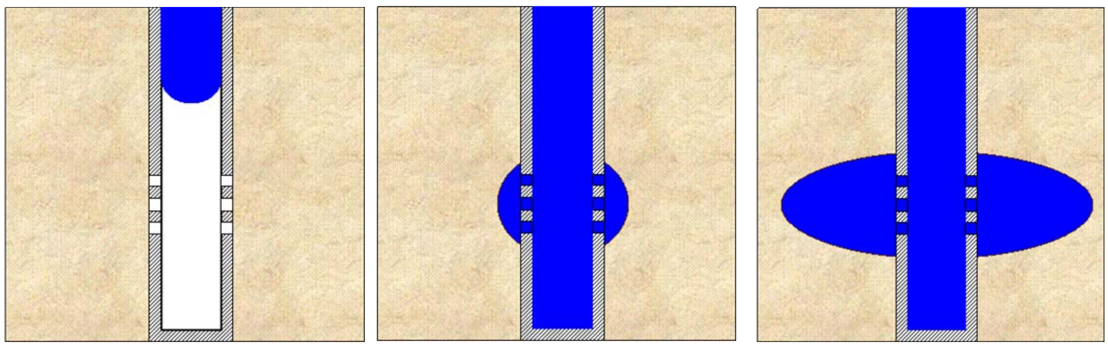
Formation permeability is the dominating factor affecting gas production. Low-permeability formations require stimulation because the permeability of the formation is too low for the wells to produce naturally at economic flow rates. Although the reservoir may contain significant hydrocarbons, sufficient production can be obtained only after large, conductive hydraulic fractures are created in the formation. Holditch (2006) considers the best definition of tight gas as follows: "A reservoir that cannot be produced at economic rates nor one can recover from it economic volumes of gas without large-scale hydraulic fracturing treatment or advanced wellbores."

The first hydraulic fracturing treatment was successfully conducted in the Hugoton gas field in July 1947 (Gidley, 2001). This well was chosen for hydraulic fracturing because it had a low deliverability. The well was earlier completed with acidizing. So fracturing this well offered a direct comparison between acidizing and fracturing. The overall deliverability from the well was not increased. Therefore it was incorrectly concluded at the time that fracturing would not replace acidizing.

However, by the mid 1960s, propped hydraulic fracturing had replaced acidizing as the preferred stimulation method in the Hugoton field (Gidley 2001). The use of large volumes of cheap water based fluids pumped at very high rates had proved to be an effective and economical procedure. Since the 1960s, hydraulic fracturing has developed from a fairly small, simple procedure to a complex process involving improved engineering techniques. Fracture treatments in the 1990's normally used a cross-linked polymer gel system carrying large volumes of sand or ceramic beads to prop open the fractures. These massive hydraulic fracturing treatments resulted in long propped fractures and turned many marginal tight gas plays into economic development opportunities.

The basic hydraulic fracturing processes are shown in **Fig. 1.9.** In the first stage, a small amount of fluid called the prepad is pumped down the well to fill the well and to check if the mechanical condition of the well is satisfactory, and to break down the formation. In the next stage, a neat fluid called pad is pumped at high injection rates creating high wellbore pressure. This pad causes the fracture to grow and cools the formation near the fracture. Then, proppant is transported with a viscous slurry into the fracture. The main purpose of the viscous slurry is to suspend the proppant uniformly until it is transported deeply into the fracture. The proppant is used to keep the fracture open to provide a conductive path for gas to flow down the fracture and into the wellbore. Finally, the viscous fluids are broken using chemical additives to reduce the viscosity so that the fracture fluid will flow back and the fracture will close and trap the proppant.

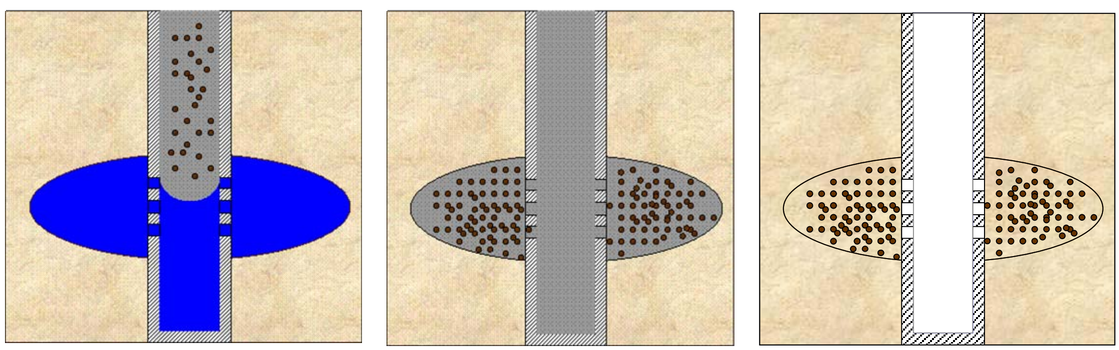
Hydraulic fracturing can improve well productivity by overcoming any drilling or completion damage that may have occurred near the well bore. A deeply penetrating fracture also improves production by changing the reservoir flow pattern. **Fig. 1.10** shows the flow path of streamlines before and after the fracture stimulation. The well produces under radial flow conditions before the fracture stimulation as shown in Fig. 1.10a. Fig. 1.10b shows the early-time flow regime after the fracture has been created. This early-time flow is called flush production. The well may make enough gas to pay out the costs of the fracture treatment and sometimes the cost of the entire well. Fig 1.10c shows the late time pseudo radial flow from long conductive fracture. In many cases, the flow pattern in the reservoir will be elliptical.



a. Fluid is pumped down well.

b. Hydraulic pressure of fluid initiates a fracture in the reservoir.

c. Fracture begins propagating into reservoir.



d. Proppant is transported with viscous fluid into fracture.

e. Viscous fluid uniformly transports fluid deeply into the fracture.

f. Viscous fluid breaks and is allowed to flow back out of well. The formation closes upon proppants resulting in a long conductive fracture.

Fig. 1.9—Basic Hydraulic Fracturing Process. (Tschirhart, 2005)

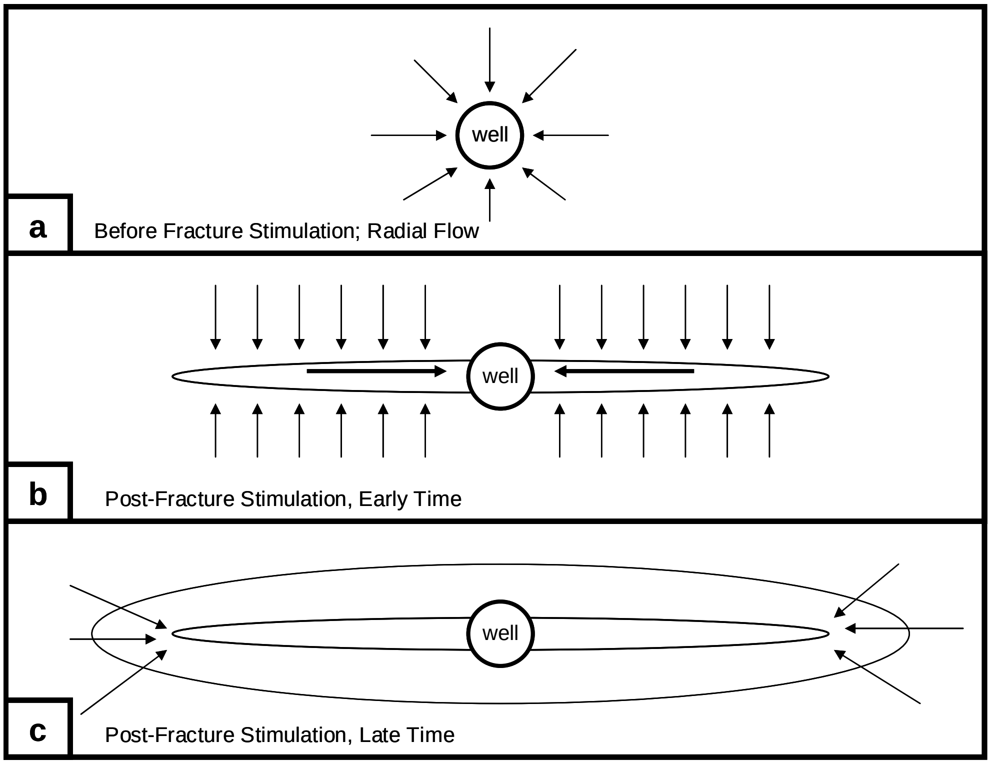


Fig. 1.10 –Flow Path for Streamlines for Wells Before and After Fracturing. (Tschirhart 2005)

1.5 Hydraulic Fracturing in Tight Gas Sands

Every tight gas well needs to be stimulated with a hydraulic fracture treatment to produce natural gas at economic flow rates and recover a volume of gas that provides an acceptable return on investment. In the Cotton Valley Formation in East Texas and Northwest Louisiana, tens of thousands of wells have been drilled, completed and fracture treated. Gas production data from these wells are publicly available for analyses. Early stimulation treatments in the Cotton Valley Sand during the 1980's were performed using cross-linked gels. Later, in the late 1990's some operators began using water fracture treatments trying to reduce fracturing costs. In recent times, some operators began using hybrid fracture treatments trying to use less polymer during the treatment while still pumping propping agents at high concentrations. Effective proppant placement with hybrid fractures has made it economical to continue developing and exploiting the resources from the Cotton Valley Sand.

Over the past few decades, many different types of fracture fluids, propping agents and treatment sizes have been tried in the Cotton Valley formation. The main objective of most treatment design engineers is to optimize the fracture treatment design to produce the best economic return on investment. The design engineer has to choose the optimum fluid, optimum proppant, optimum treatment size and make sure the optimum treatment is mixed and pumped in the field. These optimum values also depend on drilling costs, fracturing costs and other economic parameters such as gas prices, operating costs and taxes.

The various fracture treatments available are water fracture treatments, gel fracture treatments, foam fracture treatments, miceller fracture treatments, and hybrid fracture treatments. Water fracture treatments were intended to create fractures by pumping fracturing fluid composed of water, clay stabilizers, surfactants, and friction reducers, using virtually no polymer gel. A proppant concentration of 0.5 to 1 ppg maximum is added to the later portion of the treatment. The main advantage of a water fracture treatment is that it is simple and cheap. However, because of the lower volume of propping agents and the low viscosity of the fracturing fluid, a water fracture treatment will have short low conductivity unless a really good lower barrier to fracture growth exists and a large proppant bank can be formed. Because cross-linked gel treatments are more expensive than water fracture treatments, some companies started using slick-water fracture treatments to stimulate the Cotton Valley to reduce costs. Some of those companies stated in SPE papers (Mayerhofer, 1997, Mayerhofer and Meehan, 1998) that the well performance after a slick water fracture treatment is about the same as after a gel treatment, but the cost is less. As such, those companies believed it was more economic to use slick water fracture treatments than the cross-linked gel treatments.

Cross-linked gel fracture treatments were commonly used in the 1980's and 1990's. A gel treatment uses used water gelled with polymers and cross-linked to increase viscosity to pump large volumes of propping agents at high concentrations. The main advantage of a gel fracture treatment is long propped fractures can be achieved. Cross linked gel fracture treatments have proven to be successful in high temperature reservoirs. However, in low temperature (BHT < $250^{o}F$), reservoirs the viscous fluid may not break back to a low viscosity so it can clean up properly. The industry has used cross-linked gel fracture treatments carrying high proppant concentrations to stimulate the Cotton Valley sands for many years.

Foam fracture treatments are commonly used in low temperature and very low pressure reservoirs (Malpani, 2006). As the bottom-hole pressure is reduced, the gas will expand and the foam will break, so it cleans up fairly well.

Miceller fluids have long worm like micelles formed by surfactants in an electrolyte. The micelles are similar to long-chain polymers in gel fluids. The breaker system for miceller fluids is the hydrocarbon (oil or condensate) itself. The micelles breakup when the produced hydrocarbons mix with the fracture fluid. Miceller fluids can be the ideal fluid for low temperature reservoirs. However, miceller fluids are not economical for high temperature reservoirs. The fluid also may have problems with breakers in dry gas reservoirs.

The hybrid fracture treatment is a relatively new variation in fracture treatment design. Anadarko designed what they called a “hybrid” fracture treatment for the Cotton Valley. A hybrid treatment uses a slick water pad to create the fracture, and then switches to a low-concentration, cross-linked gel fluid to carry the proppant at moderate concentrations. Anadarko reported that the hybrid treatments worked well in the Cotton Valley formation in East Texas.

East Texas and Northwest Louisiana has many tight gas fields in the Cotton Valley formation as shown in **Fig. 1.11.** Data used in this research came from the Oak Hill and the Elm Grove field of the Cotton Valley formation. The production from low permeability Cotton Valley sandstones became commercial in the 1970s as a result of increased gas prices and technical advances in hydraulic fracturing techniques. Today over one thousand producing wells have been drilled both in Caspiana and Elm Grove fields and all of them have been hydraulically fracture treated to achieve commercial gas production rates (Ozobeme 2006). The Cotton Valley is a medium temperature reservoir

($250^{\circ}F$). Water fracture treatments, gel fracture treatments, and hybrid fracture treatments are the most common fracturing treatments pumped in this field. Selection of optimum fracture treatment procedures for this field has been a problem.

In this study we have reviewed production data from the Carthage and Oak Hill Cotton Valley fields in Texas and the Elm Grove field in Louisiana to evaluate well performance as a function of the fracture treatment type. We also have performed a detailed economic evaluation for wells drilled by Matador Resources in the Elm Grove Field to determine the optimum treatment type as a function of drilling costs, completion costs, operating costs and gas prices.

1.6 Objectives

The objectives of this research are as follows:

- Analyze production data from a sample of Cotton Valley wells in East Texas Oak Hill field to determine if gas production could be correlated with how and when the well was completed and stimulated.
- Analyze production data from a sample of Cotton Valley wells in the East Texas Elm Grove field using an analytical reservoir simulator to see if we could estimate values of fracture half-length, drainage area, and permeability-thickness product that can be correlated with how and where the well was drilled and completed.

- Analyze production data from a sample of Cotton Valley wells in the East Texas Elm Grove field using analytical simulator to estimate values of 5 year cumulative gas production.
- Use the basic drilling and completion cost values for wells operated by Matador Resources in the Elm Grove Cotton Valley sandstone to determine Rate of Return (ROR) for various values of 5 year cumulative gas production, and gas prices.
- Estimate the minimum value of 5 year cumulative gas production required to achieve a ROR of at least 10% for all treatments for the Cotton Valley sands of the Elm Grove field.
- Use the ROR values to determine how to recognize economic wells after just a few weeks or months of gas production for the Cotton Valley sands of the Elm Grove field.

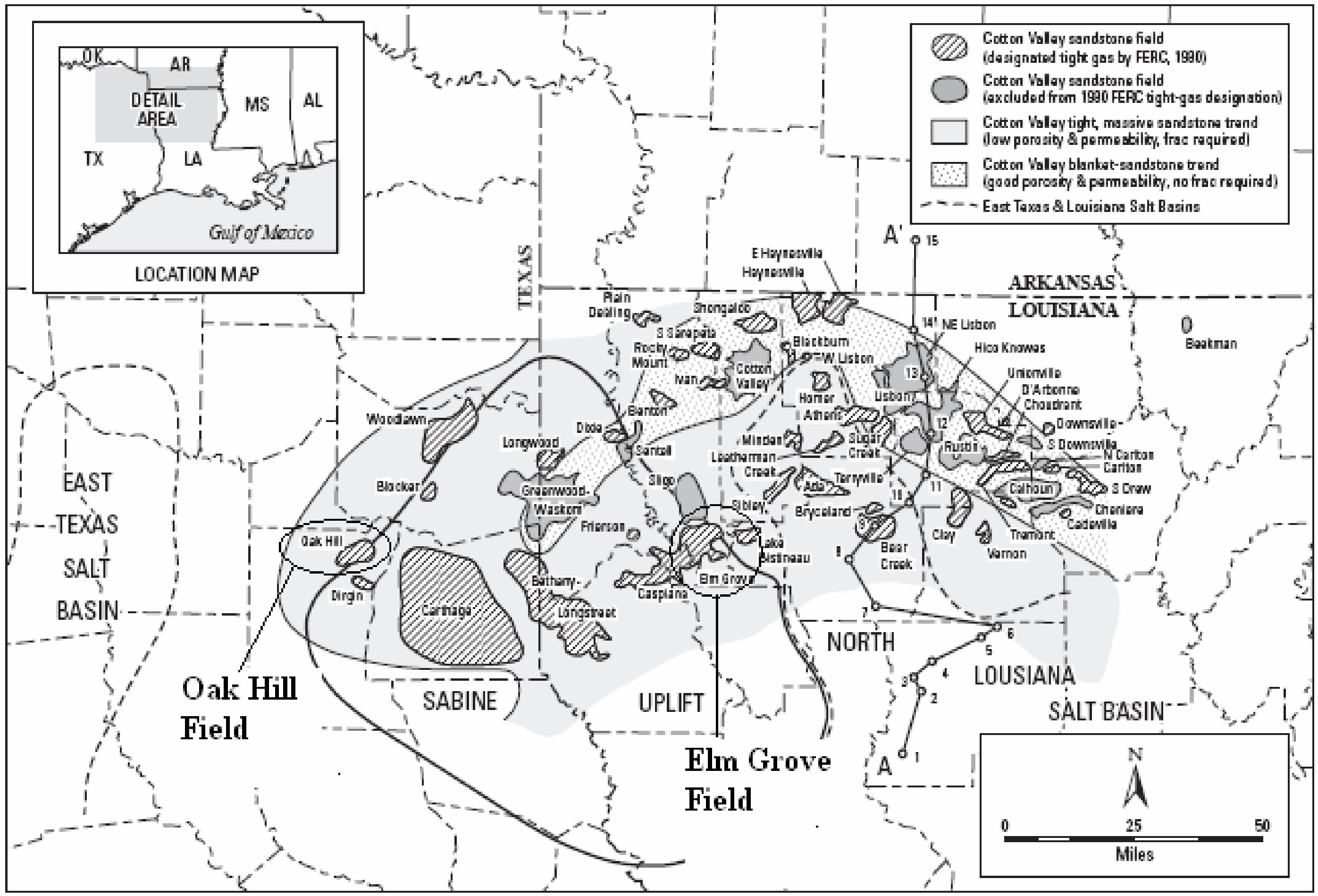


Figure 1.11—Map of Northeastern Texas and Northwestern Louisiana Sandstones in Northeastern Texas and Northwestern Louisiana that have Produced Hydrocarbons. (Bartbeger in USGS Bulliten 2002)

CHAPTER II

LITERATURE REVIEW

2.1 Fracture Fluid Selection for Gas Wells

Over the past few decades, many different types of fracture fluids, propping agents and treatment sizes have been tried in the Cotton Valley formation. The objective of most treatment design engineers is to optimize the fracture treatment design to produce the best economic return on investment. The design engineer has to choose the optimum fluid, optimum proppant, optimum treatment size and make sure the optimum treatment is mixed and pumped in the field. These optimum values also depend on drilling costs, fracturing costs and other economic parameters such as gas prices, operating costs and taxes.

With all the permutations and combinations available for fracturing fluids, it is not an easy task to develop simple selection criteria for identifying the right fracturing fluid for a particular reservoir. Numerous papers have been published in evaluating the optimum treatment and the optimum fracture fluid.

Holditch and Xiong in 1993 made one of the first attempts to build rules for fracture fluid selection. They interviewed several experts in hydraulic fracturing, reviewed technical documents, and verified the experimental data to identify a consensus recommendation. They developed rules to select the proper base fluids for a particular reservoir situation as shown in the **Fig. 2.1**. These rules allow one to select the fracturing parameters consistently and with precision. They also gave rules to select the base fluid, additives, fluid loss additives, gel stabilizers, propping agents, and optimizing the fluid volume. Further, they concluded that by selecting two possible fluid systems and two possible propping agents one can perform a detailed economic analysis and optimize the fracture fluid system and treatment volume for a given set of well conditions.

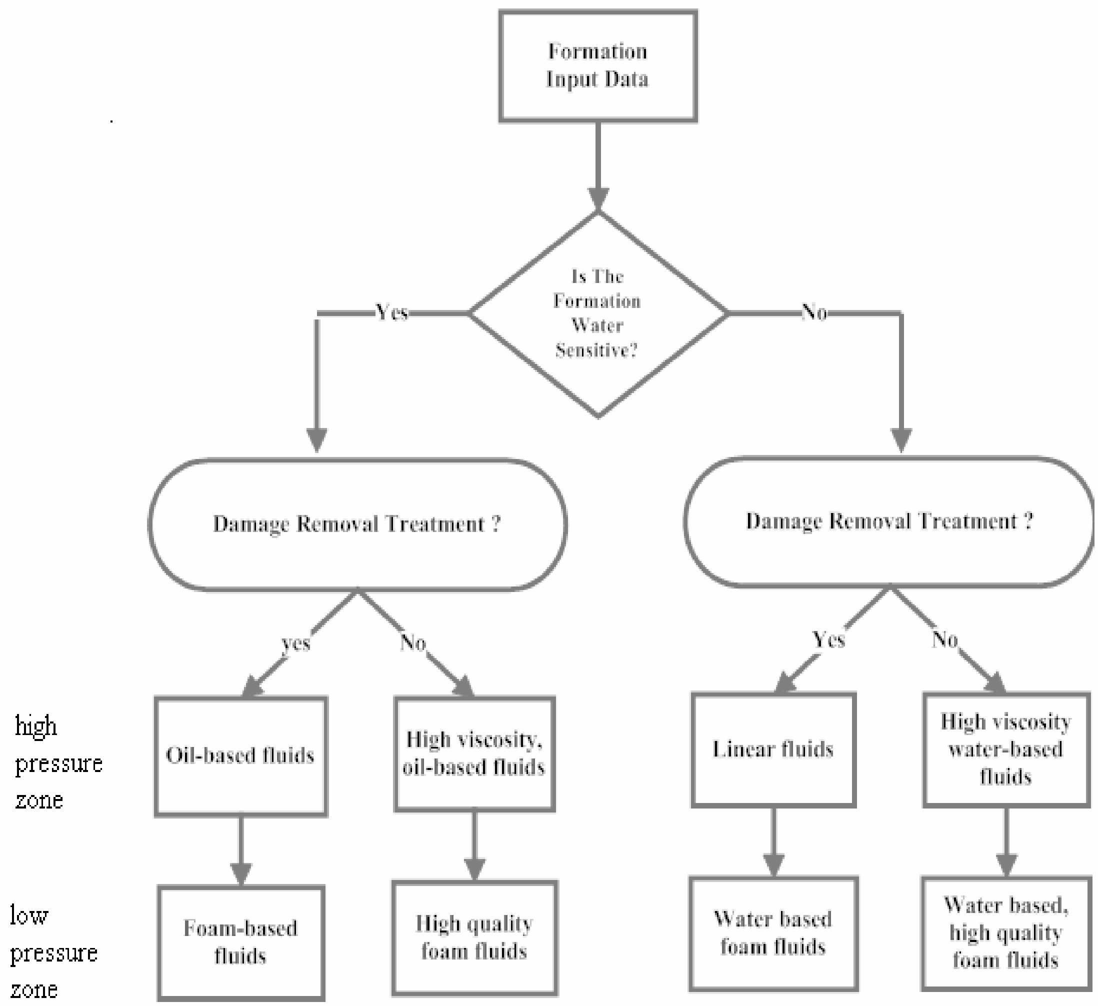


Figure 2.1—Logic Used to Select Fracturing Fluid. (Holditch and Xiong, 1993)

Xiong (1995) applied fuzzy logic to design well stimulation treatments. He said the selection of a fracture fluid involves the consideration of many parameters. Xiong developed a general procedure to build a fuzzy logic evaluator for typical well stimulation problems. He said the fuzzy logic evaluator would identify all possible decisions that could be made by a human expert solving the problem.

Xiong and Holditch (1996) concluded that the fuzzy logic theory could be used to build evaluators to help engineer to not only select proper fracture fluids, but also rank all possible fluid candidates. They identified that some of the rules that experts use to make decisions that are not clearly (fuzzy) defined. They presented the issues and the logic that an engineer must apply to make correct decisions during fracture fluid selection. They also concluded that fuzzy logic is an excellent tool to represent domain expertise and knowledge in computer codes, which makes it easier to apply and transfer domain knowledge and expertise.

Gupta and Valko (2008) reviewed the work done by Holditch (1993) and Xiong (1995, 1996). They developed a chart as shown in **Fig. 2.2** that may be used as a first order approximation in narrowing the available choices. Mayerhofer (1997) concluded that the gas production from water fracture treated wells and gel fracture treated wells were comparable in a few wells that he analyzed in one particular field. Also, the treatment costs of gel fracture wells were 50% higher. He concluded that water fracture treatments are better than gel fracture treatments if the gas production is similar and the costs are lower for water fracture treatments.

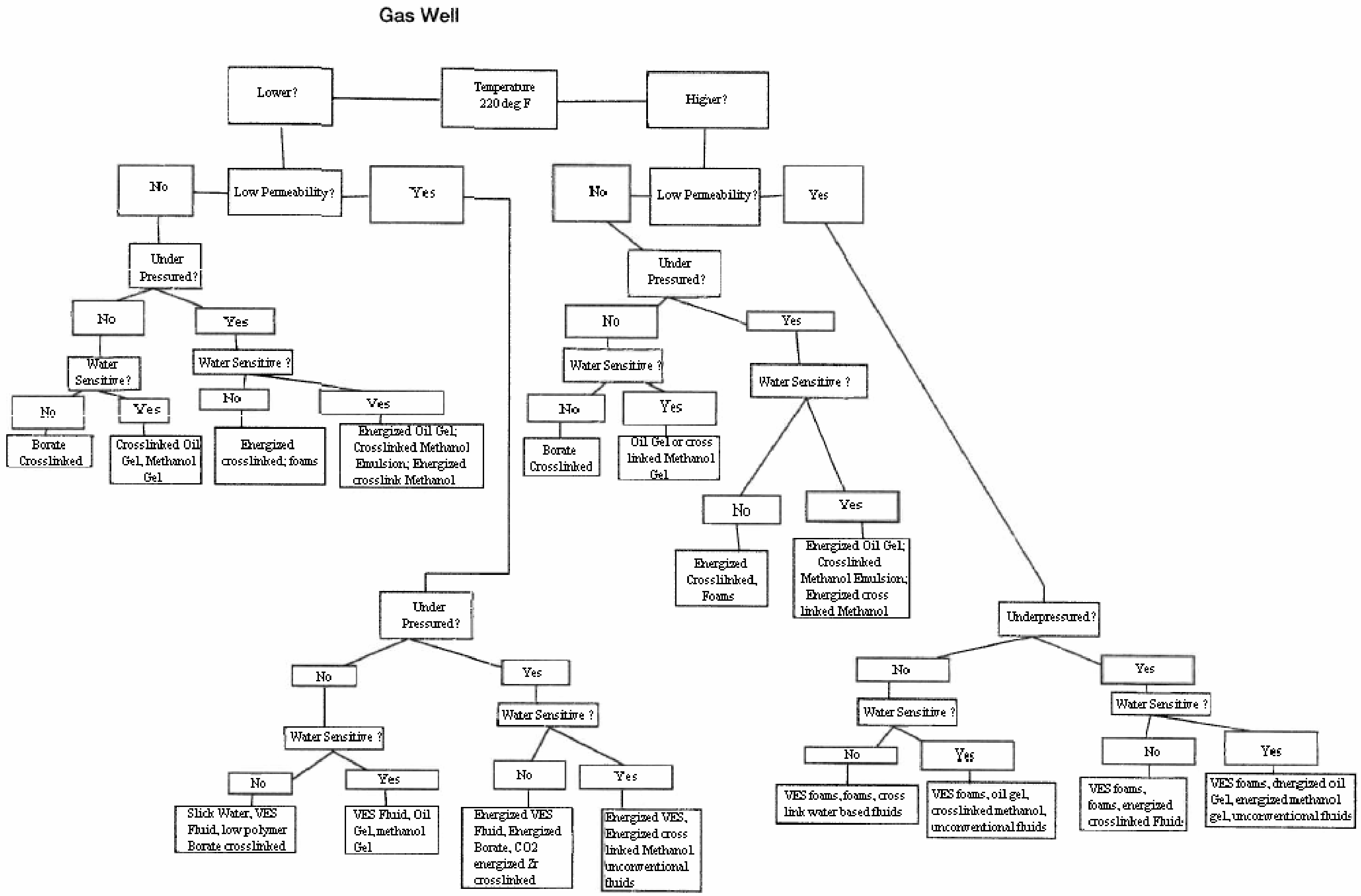


Fig 2.2—Fracturing Fluid Selection Chart for Gas Wells. (Gupta and Valko, 2008)

Mayerhofer and Meehan (1998) conducted a statistical comparison of both water fracture treatments and gel fracture treatments in a number of Cotton Valley wells using the first 6 month of cumulative gas production. For the few wells that they analyzed, they concluded that the water fracture treatment wells perform as well as the gel fracture treatment wells but at substantially lower costs. They also identified that wells fracture treated with substantially larger treatment volumes appear to produce at higher flow rates. They also indicate that long term production comparisons show water fracture wells have declining production compared to gel fracture wells. In short, Mayerhofer and Meehan showed that the production performance form the two sets of wells were similar, but the wells treated with the water fracture treatments cost less. Thus, they concluded that water fracture treatments were more economic. This conclusion has been challenged by several authors.

Poe (1999) used production data history matching and pressure-transient analysis to evaluate the production performance of over 200 wells in the low permeability reservoirs of North America. He concluded that large proppant volumes are required to effectively create long, moderately to highly conductive fractures to properly stimulate low permeability gas reservoirs. The author provided evidence that highly conductive fractures are possible only with the use of cross-linked gel fracture treatments carrying large volumes of proppant. Water fracture treatments were not considered to be nearly as good as cross-linked gel treatments.

England (2000) did a study on 100 wells of the Cotton Valley sands by history matching gas flow rates with production data type curve analysis to compare gel fracture treated wells and water fracture treated wells. From standard comparisons of flow rate versus time he showed that water fracture completions were similar to gel fracture completions when compared on the basis of one year cumulative gas production. However, when he normalized the data based on reservoir quality and pressure drawdown, he could more realistically compare the data. He could then conclude that the average gel fracture treated well performed better than water fracture treated well.

In 1999, the Cotton Valley Hydraulic Fracturing Imaging Project in East Texas was conducted with a goal of evaluating hydraulic fracture growth of conventional gel fracture treatments and water fracture treatments. A variety of fracture diagnostic tools were used on ten fracture stages in three wells including micro-seismic and downhole tilt meter fracture mapping, fracture modeling, stress tests, radioactive tracers, pressure transient well tests, and production logging. Mayerhofer et al (2000) reported that longer fractures were observed in gel fracture treatments as compared to water fracture treatments. They identified that from two post-fracture pressure buildup tests, that water fractures have much shorter fracture half-lengths. Seismic source parameters indicated that water fracture treated wells exhibit shear-type failures and gel fracture treated wells have a larger volumetric failure component, which indicates more propped fracture width. They further concluded that gel fracture treated wells are better than water fracture treated wells.

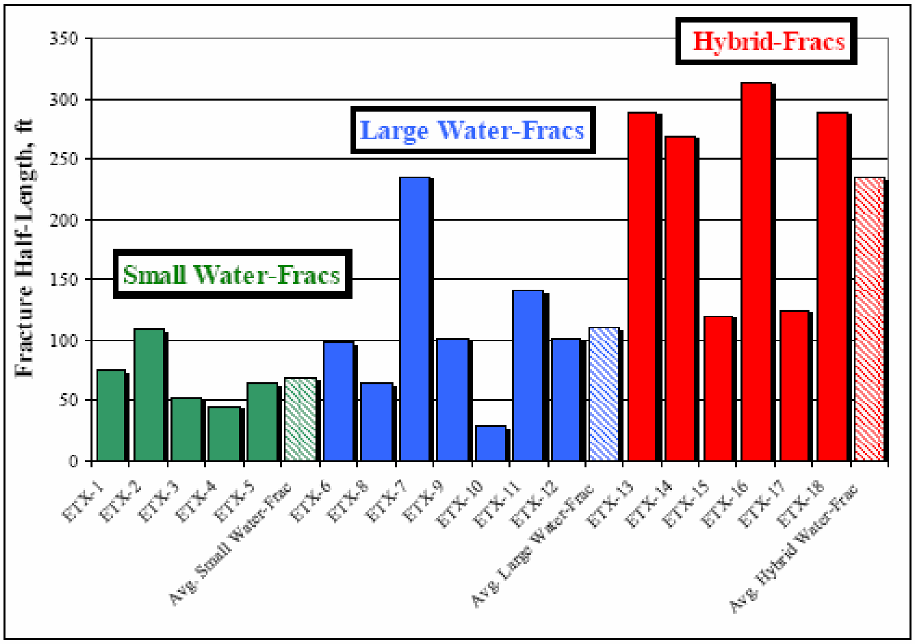


Fig 2.3—Effective Fracture Half-Lengths for Wells in Bossier Tight Gas Sands. (Rushing and Sullivan, 2005)

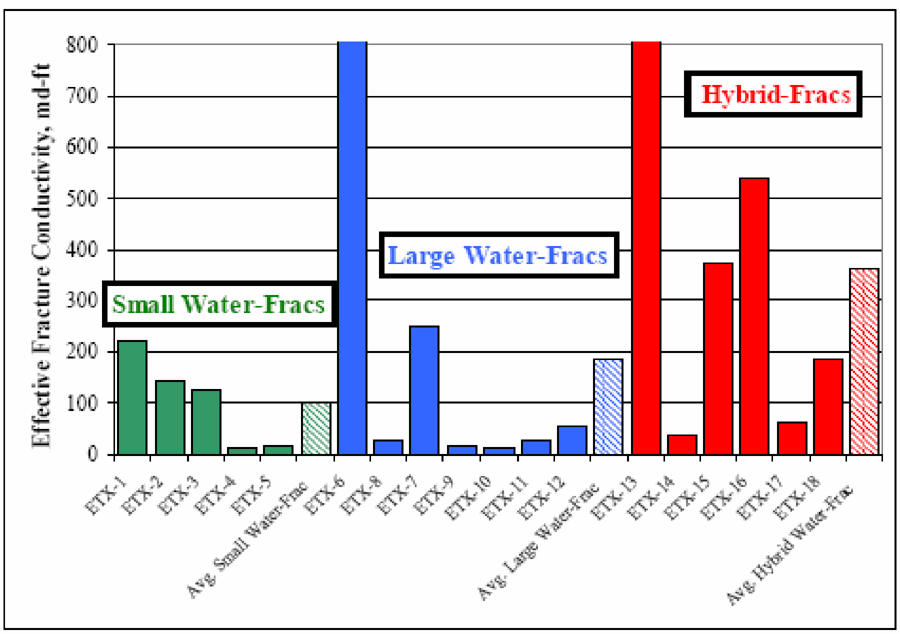


Fig 2.4—Effective Fracture Conductivities for Wells in Bossier Tight Gas Sands. (Rushing and Sullivan, 2005)

Rushing and Sullivan (2003) did a comparison of water fracture treatments and hybrid fracture treatments in the Bossier tight gas sands based on short-term pressure buildup analysis and long-term gas production analysis for 18 wells. They concluded that on average, hybrid fracture treatments generated longer effective fracture half-lengths and larger effective fracture conductivities than conventional water fracture treatments, as shown in **Fig 2.3** and **Fig. 2.4**. They also suggested that the use of large proppant concentrations in water fracture treatments does not generate longer more conductive fractures because of inconsistent placement of proppant prior to fracture closure.

Mayerhofer (2005) compared several water fracture treated wells and the hybrid fracture treated wells in the Overton Field, East Texas in the Cotton Valley formation. He performed detail production data analyses to evaluate well performance in conjunction with fracture geometry measurements provided by microseismic fracture mapping results, calibrated fracture modeling and direct production interference data. He provided clear evidence from microseismic fracture mapping that fracture half-lengths of hybrid fracture treated wells were very long compared to water fracture treated wells. He further suggested that hybrid fracture treated wells have elongated cigar-like drainage area.

Tschirhart (2005) evaluated the effect of fracture treatment type upon gas production for the tight gas Cotton Valley Sands in Carthage field in the East Texas basin. The gas production in this field began in the early 1980s and has been aggressively developed for over 20 years. Tschirhart analyzed the wells using the date of fist production as shown in **Fig. 2.5**. Tschirhart showed that the average well deliverability of new wells was decreasing with time because of pressure depletion. However, he concluded it that it is difficult to tell the difference between the production performance of the wells stimulated with medium proppant concentrations and those stimulated with low proppant concentrations as shown in **Fig. 2.6.** Hence Tschirhart concluded that water fracture treatments can be justified in the partially depleted Cotton Valley sands of the 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, he did not do an economic analysis.

Malpani (2006) re-evaluated the data from the wells in the Carthage field used by Tschirhart (2005) by grouping the data as a function of initial reservoir pressure, rather than time. He found that as the amount of propping agent increases in a treatment, the gas production from the well also increases if you group the wells on the basis of reservoir pressure rather than DOFP. He also history matched gas production from a sample of Cotton Valley wells in the Carthage field using an analytical reservoir simulator to indicate that medium proppant concentration treatments creates longer effective fracture half-lengths, as well as have larger drainage area than the low proppant concentration treatment wells. However, Malpani did not include any economic calculations to help determine the optimum treatment.

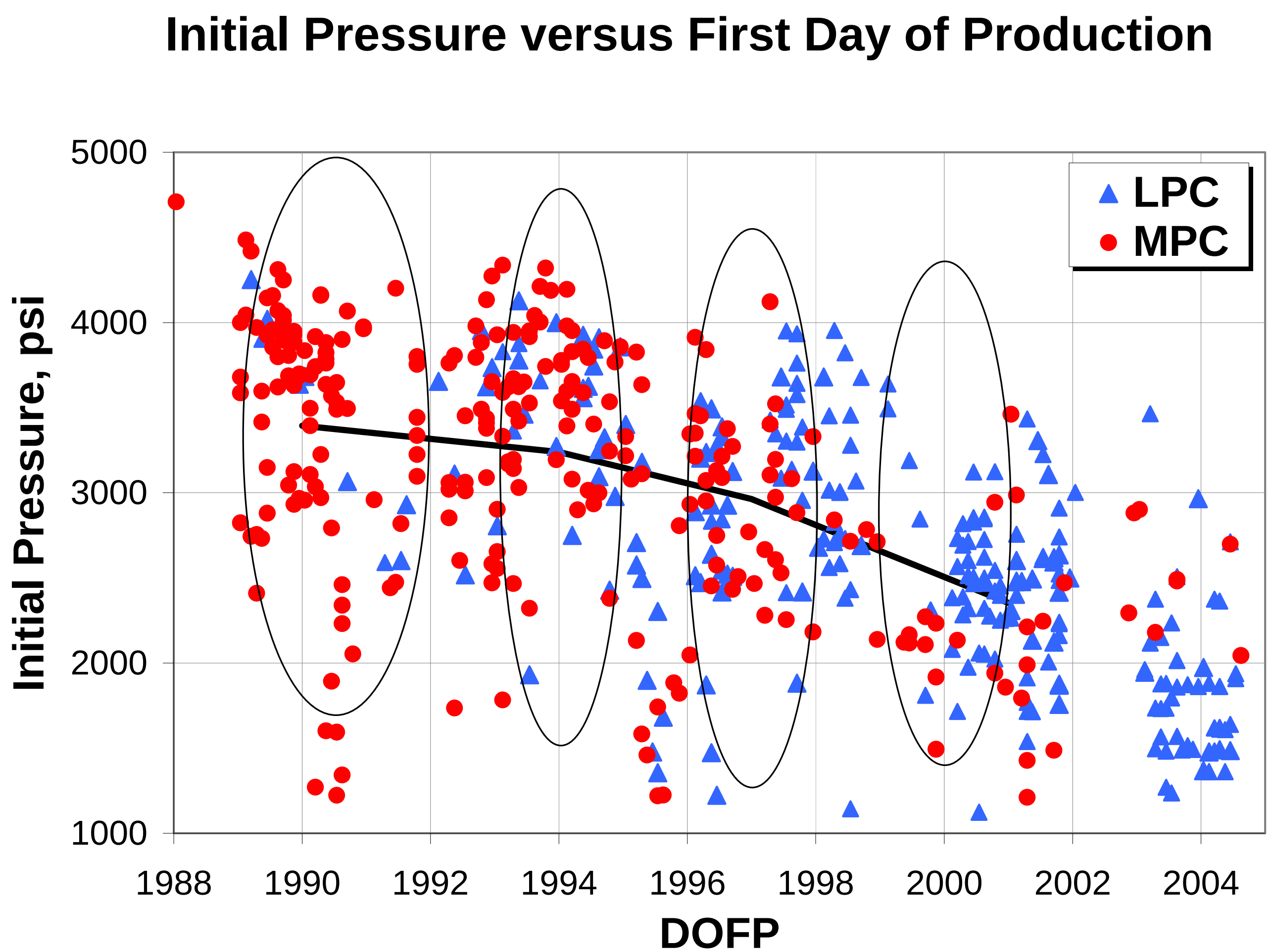


Figure 2.5—Well Categories by First Day of Production. (Tschirhart, 2005)

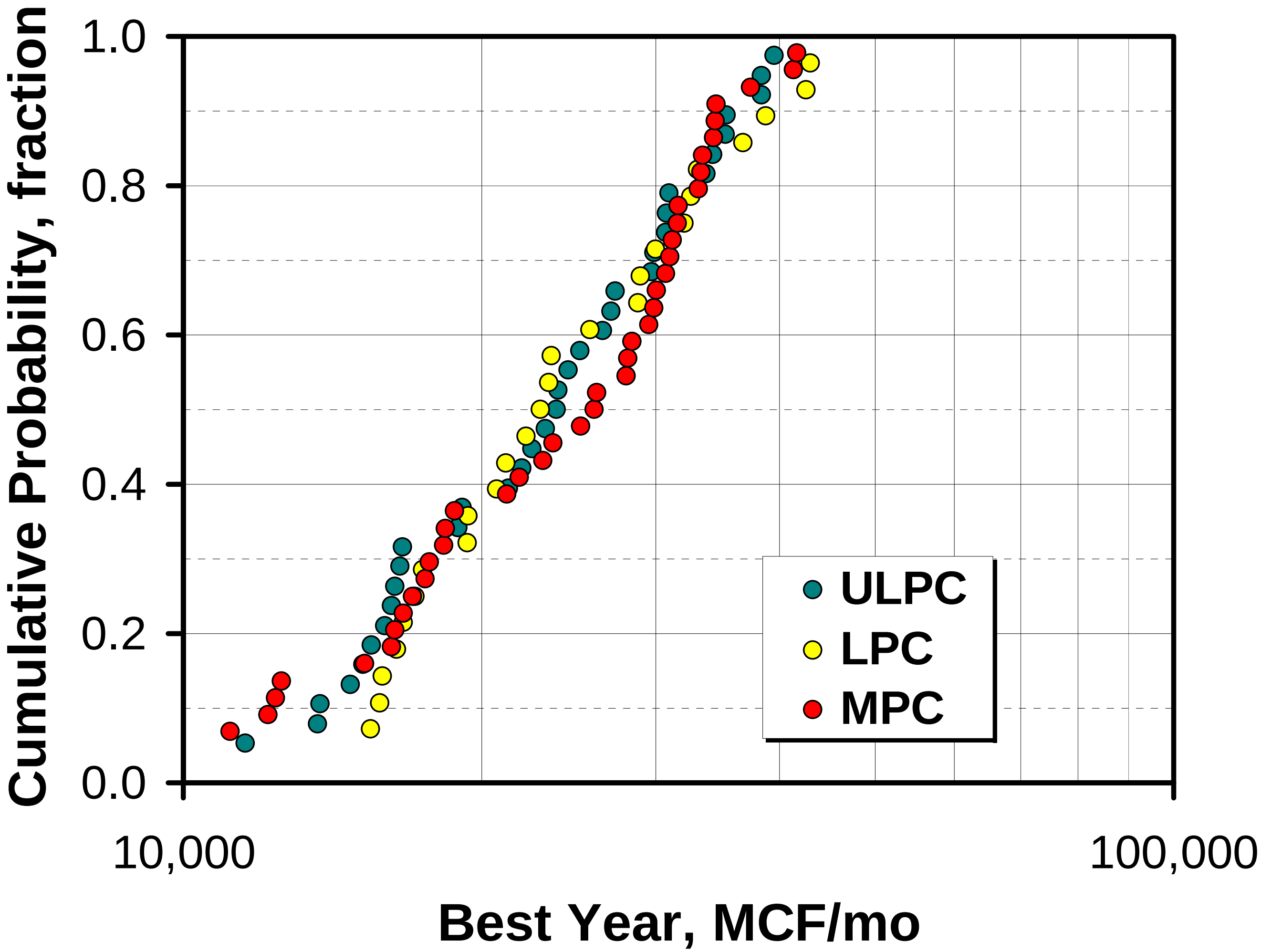


Figure 2.6—Cumulative Distribution Curves of Best Year for Wells. (Tschirhart, 2005)

Malpani (2006) also developed a flow chart to help engineers select the appropriate type of fracturing fluid for a specific set of reservoir conditions. The flowchart shown in **Fig 2.7** includes eight key parameters including bottom-hole temperature, bottom-hole pressure, presence of natural fractures, type of lower and upper barrier, modulus of the formation, thickness of the pay, and desired fracture half-length. He came up with this flow chart after getting experts opinion on how they select the fracture fluid based on the given set of reservoir conditions. From this study he developed guidelines on when water fracture treatments should and should not be pumped.

2.2 Success of Hybrid Fracture Treatments

Hybrid fracture treatments are used to describe several different types of fracture stimulations consisting of various combinations of slickwater, linear gelled, and cross-linked gelled fluid systems. In general, a hybrid fracture treatment consists of a waterfrac prepad followed by a cross-linked gelled fluid. The initial long thin fracture is created with the slick water prepad; subsequently the width and the height of the fracture will increase as cross-linked gelled fluid is pumped into the fractue.

Rushing and Sullivan (2003) presented the results from fracture treatments done in the Bossier tight gas sands in the East Texas Basin. They compared conventional water fractures with hybrid water-fracture technology. They concluded that hybrid water fractures generated longer effective fracture half-lengths and fracture conductivities than conventional water fractures.

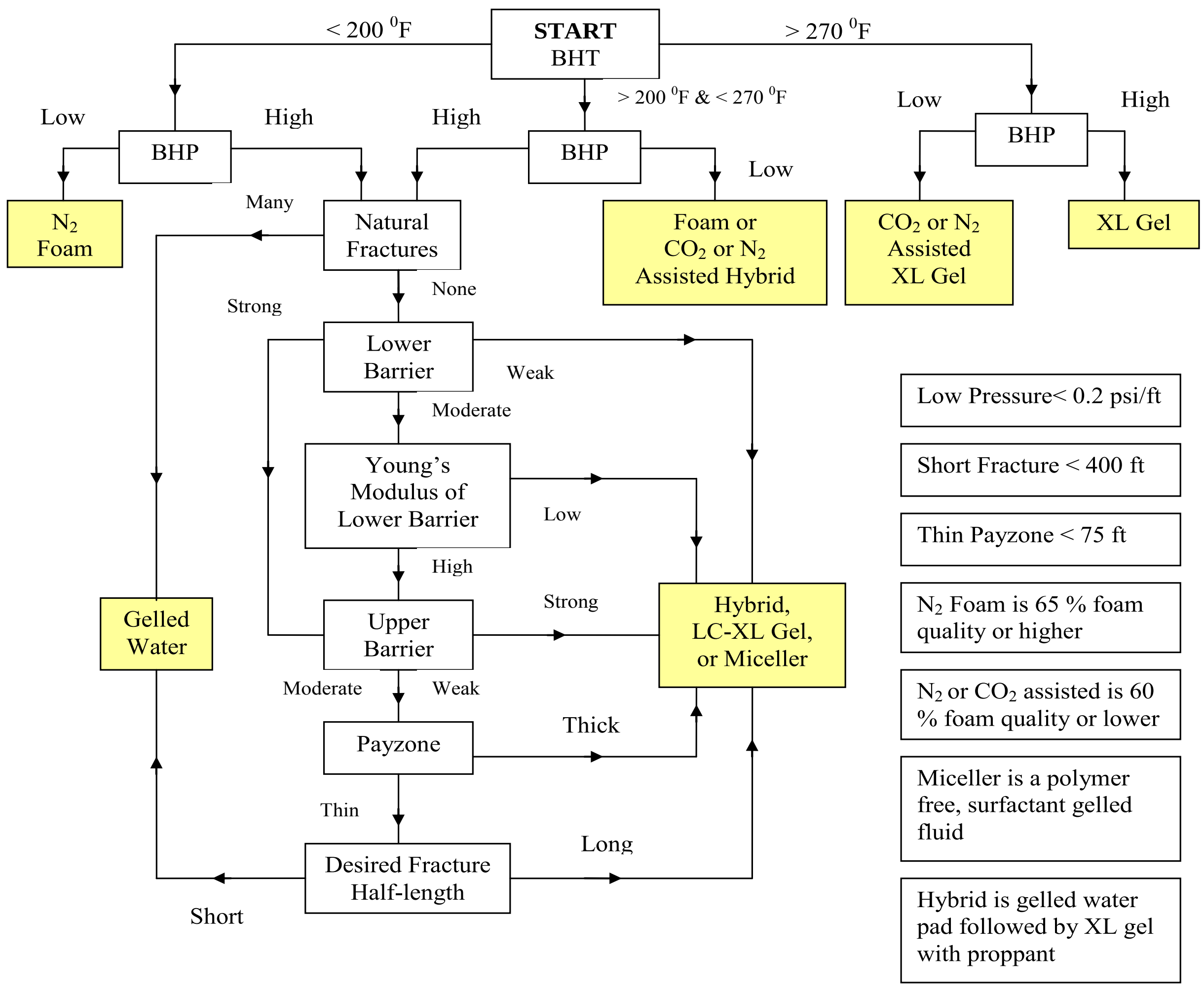


Figure 2.7—Fracture Fluid Selection for Tight Gas Sands. (Malpani, 2006)

Sharma and Gadde (2004) compared water and gel fracture treatments in the Bossier formation with the help of well data from 6 wells. They indicated that hybrid fractures produce longer propped fracture half-lengths than cross-link gel or water fracture treatments.

Coronado (2006) did a comparative study of the hybrid fracture treatments, gel fracture treatments, and water fracture treatments of the tight gas sandstone in Anadarko field. From his comparative study between hybrid fracture treatments versus cross-linked gel fracture treatments he found that hybrid fractures had more propped fracture half-length than the gel fractures. The prepad used in hybrid fractures acted as cooling agents which led to lower chemical loading. Also the hybrid fracture treatments had less polymer damage to the formation.

In his comparison of hybrid fractures versus water fractures, Coronado concluded that water fractures could not carry the proppants effectively into the formation. Water fracture treatments had high settling velocities which led to banking effects that limits the fracture half-length which created an uneven distribution of proppant. This inefficient proppant displacement in water fractures could also cause bridging of proppant at the perforations causing high pressures and possibility premature shutdown. Finally, he concluded that hybrid fractures are better than both water fracture treatments and gel fracture treatments.

Handren (2007) tried to explain the success of hybrid fracture treatments on wells of East Texas Cotton Valley Taylor with the help of a case study on 6 wells. He concluded that the hybrid fracture wells produced more than the conventional gel fracture wells based on 180 days production. He identified that the there was considerable improvement in the well recovery of hybrid fracture wells.

2.3 Different Kinds of Fracture Lengths

There are three values of fracture length that can be evaluated in any design. These three values are the created fracture length, the propped fracture length and the effective fracture length. Created fracture length is defined as the crack length in the rock. It can be estimated with fracture propagation models. Propped fracture length is the distance in the fracture from the wellbore that contains propping agents. In many cases, the propped length will be 70 to 80 % or more of the created length.

The effective fracture length is that part of the proppant length that has high enough proppant concentration to allow the fracture fluid to clean up so that natural gas can flow in the fracture. Unfortunately, the effective fracture length is often 10 to 50% of the propped fracture length. To compute flow rate and cumulative gas production, the only length that matters is the effective fracture length. In most cases, the designed value of created fracture length was probably achieved. Also, in most cases the designed value of propped fracture length was also achieved. However, due to insufficient proppant concentration, or insufficient proppant transport, or the use of the wrong propping agent, or a fracture fluid that does not break to a low viscosity fluid, the effective fracture length does not provide optimal production results. (Wang, 2008)

2.4 Production Data History Matching

Matching the production data correctly with a reservoir model gives estimates of fracture dimensions, permeability, and drainage area. These values can be used to understand the different fracture treatments, help us in the fracture design process, and allow us to forecast gas production flow rates.

Gas production history matching is done to determine reservoir properties while matching real production data from a well. This process is time consuming if done without using an automated computer process. To speed up the solution time, we use automatic history matching with the help of computers. Such computer programs use non-linear regression algorithms. The recent forms of automatic history matching use a gradient based optimization technique that automatically varies the reservoir parameters until a history match of the well is obtained. A few simulators also offer a feature to allow the user can fix any reservoir parameter which are well known in the reservoir, and obtain the match by varying the unknown parameters.

The main disadvantage of these automatic history matching of production data is the non-uniqueness of the solution when only little data are available to analyze. It is possible to obtain very good matches for completely different values of effective fracture half-length and gas permeability. Tschirhart (2005) made an attempt to determine values of permeability, effective fracture half-length, fracture conductivity, and drainage area for wells in Cotton Valley sands by history matching production data. He suggested that it was very difficult to obtain unique solutions using this method when one is trying to determine permeability, fracture conductivity, drainage area, and effective fracture half-length simultaneously. He suggested that obtaining unique solutions requires prior knowledge of gas permeability obtained from pre-stimulation well tests or post-fracture buildup tests. When these tests are unavailable there is a possibility of non unique solutions.

Vera (2006) also encountered the same problems. He suggested the engineer could correlate geological data, core data, log data, and well test data together to develop a better understanding of the reservoir. He concluded that if accurate initial values of some of the reservoir properties are provided to production history matching software, then there are more chances of getting a reliable solution. He identified that most of the software available in the industry use single phase, single layer techniques.

Vera made numerous simulation runs for wells of Travis peak in East Texas. From his results he concluded that the accuracy of the multi-layer reservoir properties computed by single layer production data analysis software in tight gas reservoirs is a function of degree of variability in permeability within the layers, and the availability of production data to be analyzed. More accurate matching is possible as more production data became available. He further gave recommendations on how to use the production data analysis software accurately.

2.5 Rate of Return

The Rate of Return (ROR) is the ratio of money gained or lost on an investment relative to the amount of money invested. The amount of money gained or lost may be referred to as interest and the money invested may be referred to as the asset, capital, principal, or the cost basis of the investment. ROR is usually expressed as a percentage rather than a decimal value.

ROI does not indicate how long an investment is held. However, ROI is most often stated as an annual rate of return, and it is most often stated for a calendar or fiscal year. ROI is used to compare returns on investments where the money invested is not easily compared using monetary values. It is a measure of cash generated by an investment, or the cash lost due to the investment.

ROI values are typically used to make personal financial decisions for investments in which capital is at risk. Companies compare ROR values for different projects to select which projects to pursue in order to generate maximum return.

CHAPTER III

METHODOLOGY

3.1 Steps Required to Accomplish the Objectives

In this research, we used production data from hundreds of wells to evaluate the effect that fracture fluid types and volumes of propping agents have on the gas recovery from wells drilled and completed in the Cotton Valley formation in East Texas and Louisiana.

In our analysis, we performed the following tasks, which are described in detail in this chapter:

- We performed a statistical analysis of the gas production from a sample of Cotton Valley wells in the Oak Hill field to determine if the gas production could be correlated with how and when the well was completed.
- We performed a history match of gas production data from a sample of Cotton Valley wells in the Elm Grove field using an analytical simulator "Promat" (Promat, 1999) to compute estimated values for well parameters such as effective fracture half-length, drainage area, reservoir dimensions and permeability.
- We evaluated the history matched parameters of the Cotton Valley wells in the Elm Grove field operated by Matador Resources to determine if production could be correlated to where and how the well was drilled and completed. We determined which fracture treatment type was better based on gas production, drainage area and effective fracture half-length. Similarly we

determined which region of the reservoir was better based on gas production, permeability-thickness product, and drainage area.

- We performed a 5 year gas production forecast of all the wells in the Elm Grove field operated by Matador Resources using the analytical simulator Promat to estimate the 5 year cumulative gas production from each well.
- We did an economic analysis to compute the ROR for various values of 5 year cumulative gas production, gas prices, drilling costs, and completion costs for the Cotton Valley wells in the Elm Grove field operated by Matador Resources using a software program called PHD Win.
- We computed the minimum value of the 5 year cumulative gas production required to achieve a ROR of at least 10% for all treatments. We also computed the mean 30 days production, 180 days production and the drainage area of the wells to achieve this 5 year cumulative gas production to determine how to recognize economic wells after just a few weeks or months of production.

3.2 Data Gathering

In this work, we have used pressure, production and the reservoir data on the Cotton Valley sands of the Oak Hill field and the Elm Grove field.

3.2.1 Reservoir Data

Reservoir data such as formation temperature, initial reservoir pressure, net pay thickness, wellbore radius, porosity, water saturation, water compressibility and formation compressibility for the wells in Elm Grove field were obtained from Matador Resources. **Fig.3.1** illustrates one panel of the reservoir data required to run Promat.

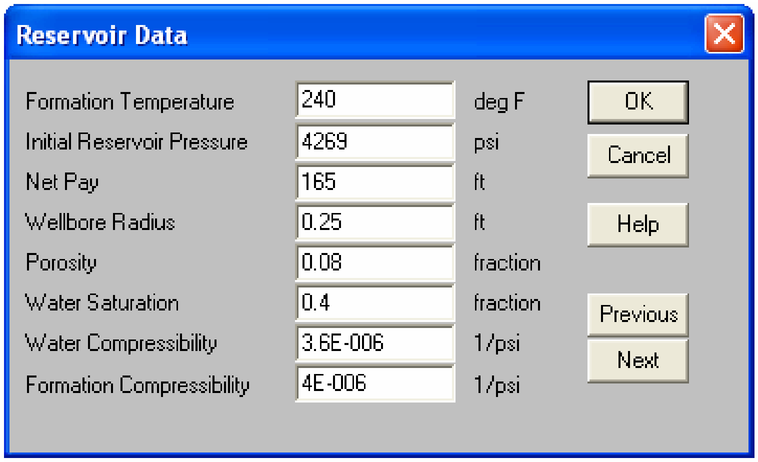


Figure 3.1—Reservoir Data for Elm Grove Field Obtained from Matador Resources.

3.2.2 Production Data

Production data for the Oak Hill field was obtained from IHS. We had data from 773 wells drilled in the Cotton Valley formation. We used the best 3 months and best 6 months production data indicator to help us evaluate the effect of completion type upon gas recovery. Matador Resources provided daily gas production data for 25 wells in the Elm Grove field drilled and completed in the Cotton Valley sands.

3.2.3 Pressure Data

Initial reservoir pressures for the wells in the Oak Hill field were obtained from the G-1 forms that we obtained from the Drilling Info Website (www.info.drillinginfo.com). We could only obtain G-1 forms for 190 wells where both the values of initial reservoir pressure and the information on how the well was completed and stimulated were included. For the Oak Hill wells, Matador Resources provided daily well head pressure information. These data were converted to bottom-hole pressures using the Cullender-Smith equations.

3.2.4 Fracture Treatment Data

We obtained data on how each well was fracture treated, such as the amount of sand pumped and the fracture fluid volumes into each well from the G-1 data for the Oak Hill field. For most wells, these data were not provided in great detail. As such, we used the total fluid pumped and the total proppant pumped to evaluate the type of treatment used to complete each of the wells. For the Elm Grove wells we obtained this data from the completion reports given by Matador Resources.

3.2.5 Geological Maps and Well Locations

Figures 1.9, 3.2, 3.3, and **3.20** represent various maps of the Elm Grove and the Oak hill field. They have been obtained from various sources which have been properly referred.

3.3 Bottom Hole Pressure (BHP) Calculations

BHP calculations have been performed using Cullender and Smith equation (Peffer 1988) shown in Eq.1. Using the values of well head pressure, tubing dimensions and average reservoir parameters bottom-hole pressure can be calculated.

$$\int_{p_{tf}}^{p_{wf}} \frac{\left(\frac{p}{Tz}\right)dp}{\frac{667 f_M q^2}{d^5 (L/D)} + \left(\frac{p}{Tz}\right)^2} = \frac{\gamma_g D}{53.34} \text{ ....Eq. 1}$$

where p_{tf} = tubing head flowing pressure,

p_{wf} = Bottom Hole Flowing Pressure,

T = temperature,

Z = gas compressibility factor,

f_m = Moody friction factor,

d = pipe ID,

γ_g = gas specific gravity,

L = length of flow string,

D = true vertical depth.

3.4 Oak Hill Field Data Analysis

The prime purpose of our analyses of the gas production data from the Cotton Valley formation in the Oak hill field was to determine if the gas production could be used to evaluate the success of the well on the basis of how the well was fracture treated. Malpani (2006) did a similar detailed field data analysis of the Cotton Valley sands in the Carthage field. He grouped the wells on the basis of proppant concentration that was calculated using the total amount of fluid and proppant pumped for all stages in the well. Malpani placed all the wells he evaluated in the two groups shown in **Table 3.1**.

Table 3.1—Treatment Type Categories for Carthage Field. (Malpani 2006)

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

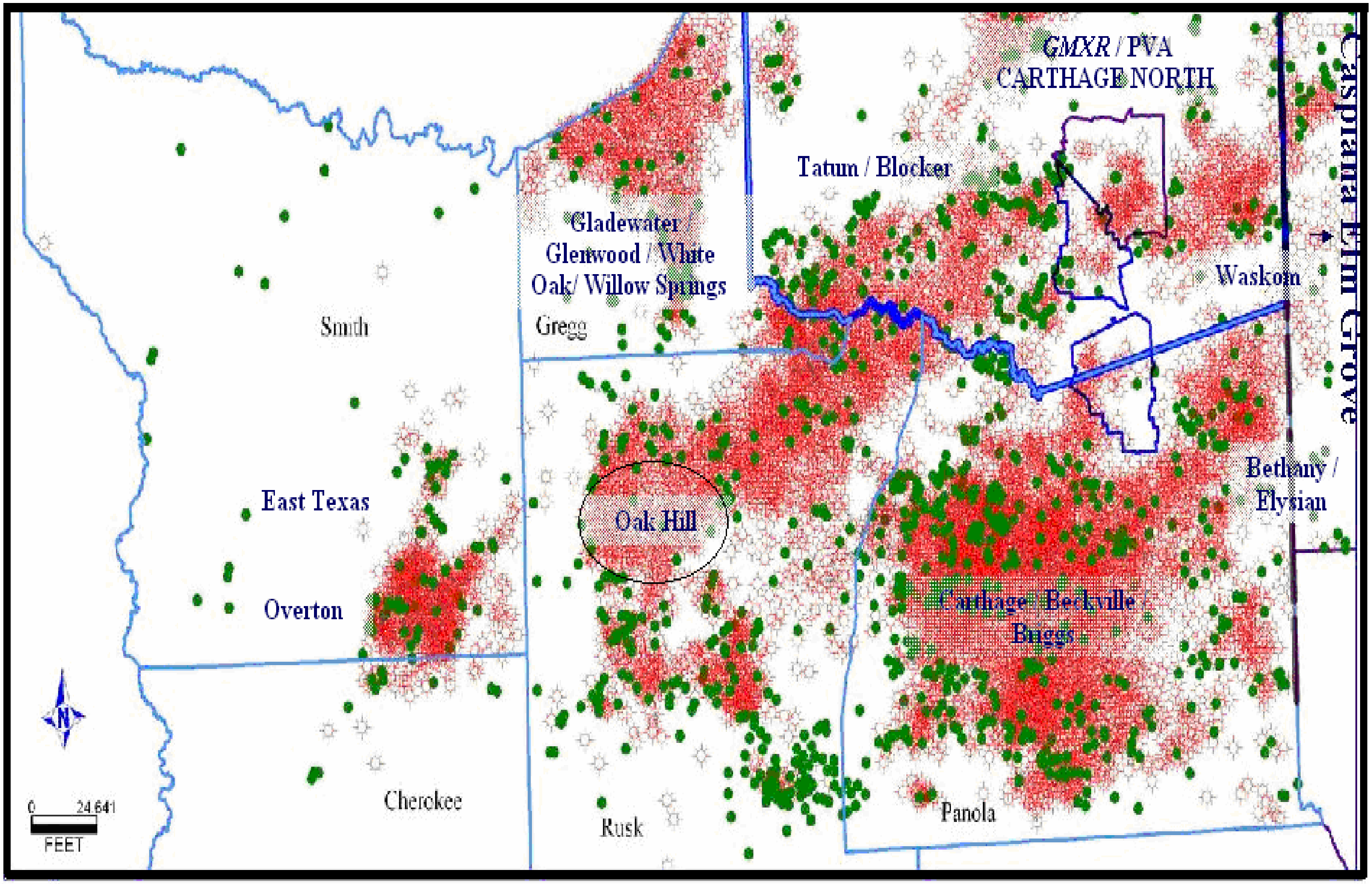


Figure 3.2—Map of Oak Hill Field. (Source--EMX Resources)

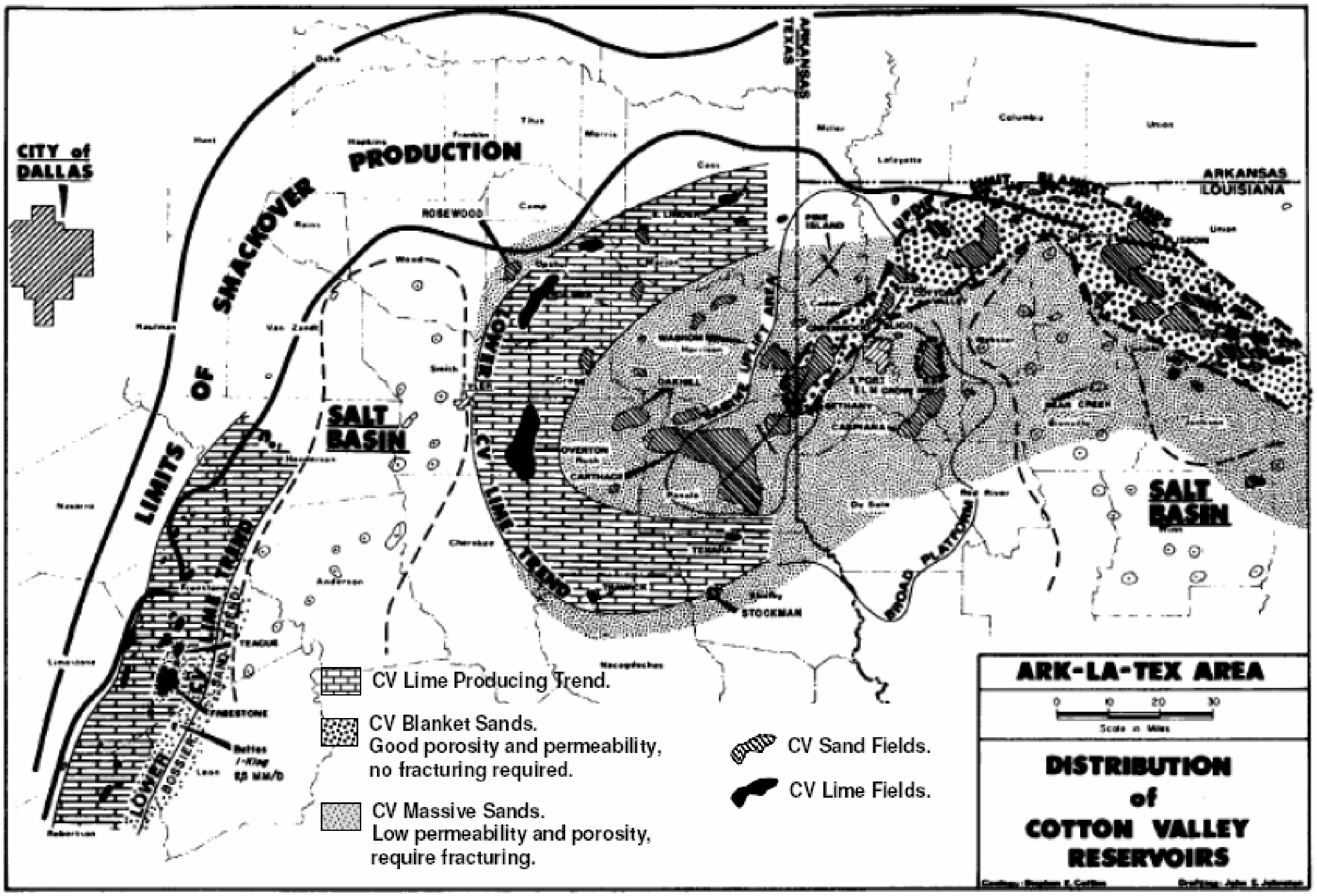


Figure 3.3—Distribution of Cotton Valley Reservoirs across East Texas and North Louisiana. (Collins 1980)

Malpani also grouped the wells based on initial reservoir pressure shown in **Table 3.2**. He used production data indicators such as Best 3 Months, Best 6 Months, and Best 12 Months of gas production to evaluate the effects of treatment type and the value of reservoir pressure.

Table 3.2—Initial Pressure Categories for Carthage Field. (Malpani 2006)

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

Figure 3.4 (Malpani, 2006) is a Cumulative Distribution Function (CDF) plot of 3 year cumulative gas production for two groups of wells as defined in Table 3.2 which suggest that Group I wells are better than the Group II wells. **Figure 3.5** is a CDF plots of the two groups based on proppant concentration which suggest that MPC wells are better than the LPC wells.

We performed a similar analysis on the Cotton Valley sands of the Oak Hill field. We had production data from 773 wells obtained from IHS and initial pressures were calculated from the data reported to Rail Road Commission (RRC). The RRC G-1 forms were available from the Drilling Info Website. We had pressure data for 190 of the 773 wells. We used the shut-in pressures to estimate the initial reservoir pressure. Since tight gas wells are in low permeability reservoirs, the wells need to be shut for a long period of time (several days or weeks) to achieve accurate estimates of the average reservoir pressure. Also, as indicated by Malpani, most of the operators do not shut wells for enough time to measure the true reservoir pressure. Hence we only use high pressure data for our study. We finally had 89 such wells for our analysis. We divided these wells consequently into two groups as shown in **Table 3.3**.

Table 3.3—Initial Pressure Categories for Oak Hill Field.

Group I	**> 3500 psi**
Group II	**< 3500 psi**

Malpani grouped the Carthage field wells based on proppant concentration, but in our analysis we grouped them on the basis of the total amount of sand pumped because of the lack of total fluid volume on many of the G-1 forms. We divided the wells into two groups shown in **Table 3.4**. **Fig. 3.7** is a histogram of the sand content of the Oak Hill field. The median value of sand content is 700,000 lbs. Therefore we assumed 700,000 lbs as the divide. The color code in Table 3.4 has been followed all through this study. We used production data indicators such as Best 3 months and Best 6 Months gas production. The Best 6 Months gas production is the best 6 consecutive months of production during the life of the well as shown in **Fig. 3.6**.

Table 3.4—Sand Content Categories for Oak Hill Field.

High Sand Content (HSC)	**> 700,000 lb**
Medium Sand Content (MSC)	**< 700,000 lb**

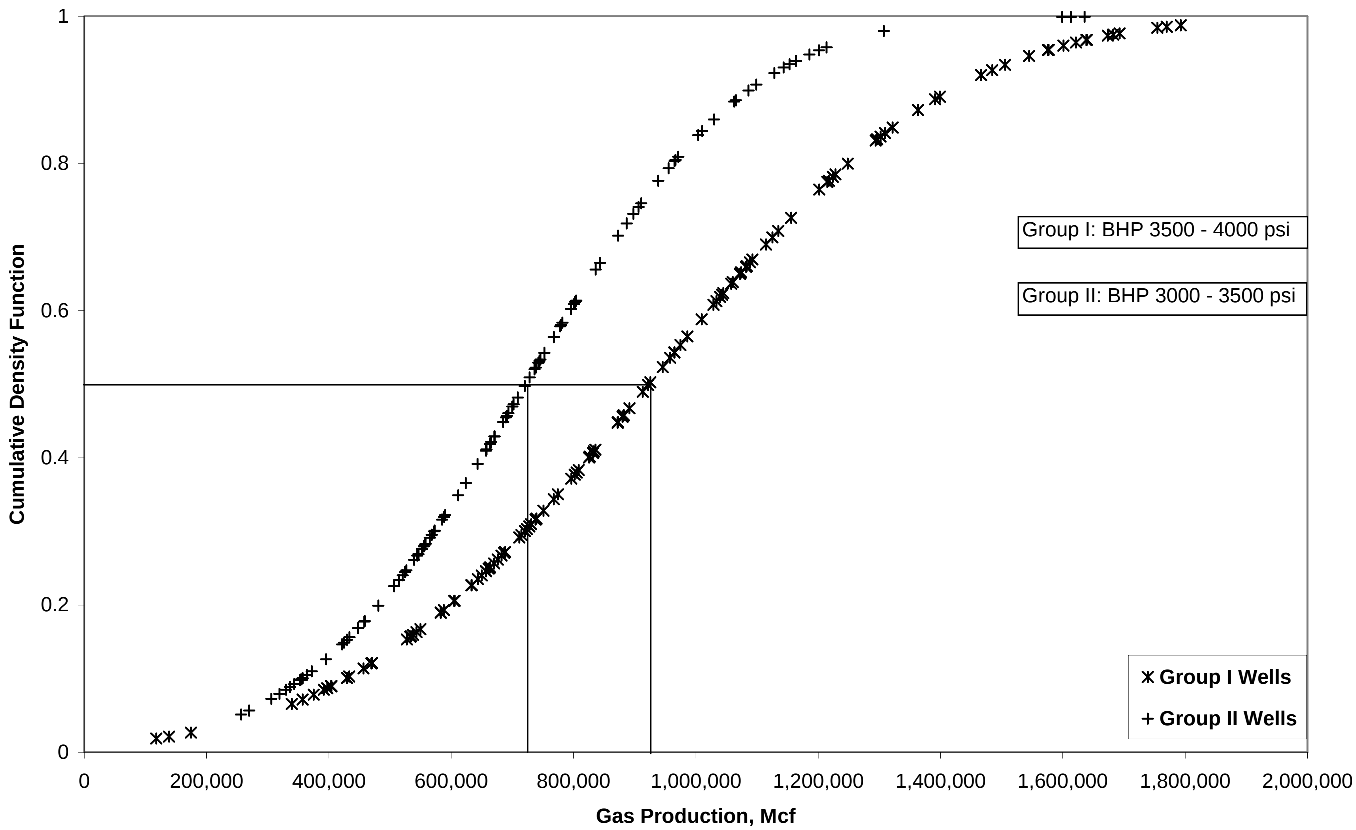


Figure 3.4—Cumulative Frequency Distribution for 3-Year Cumulative Gas Production Based on Initial Pressure for Carthage Field. (Malpani 2006)

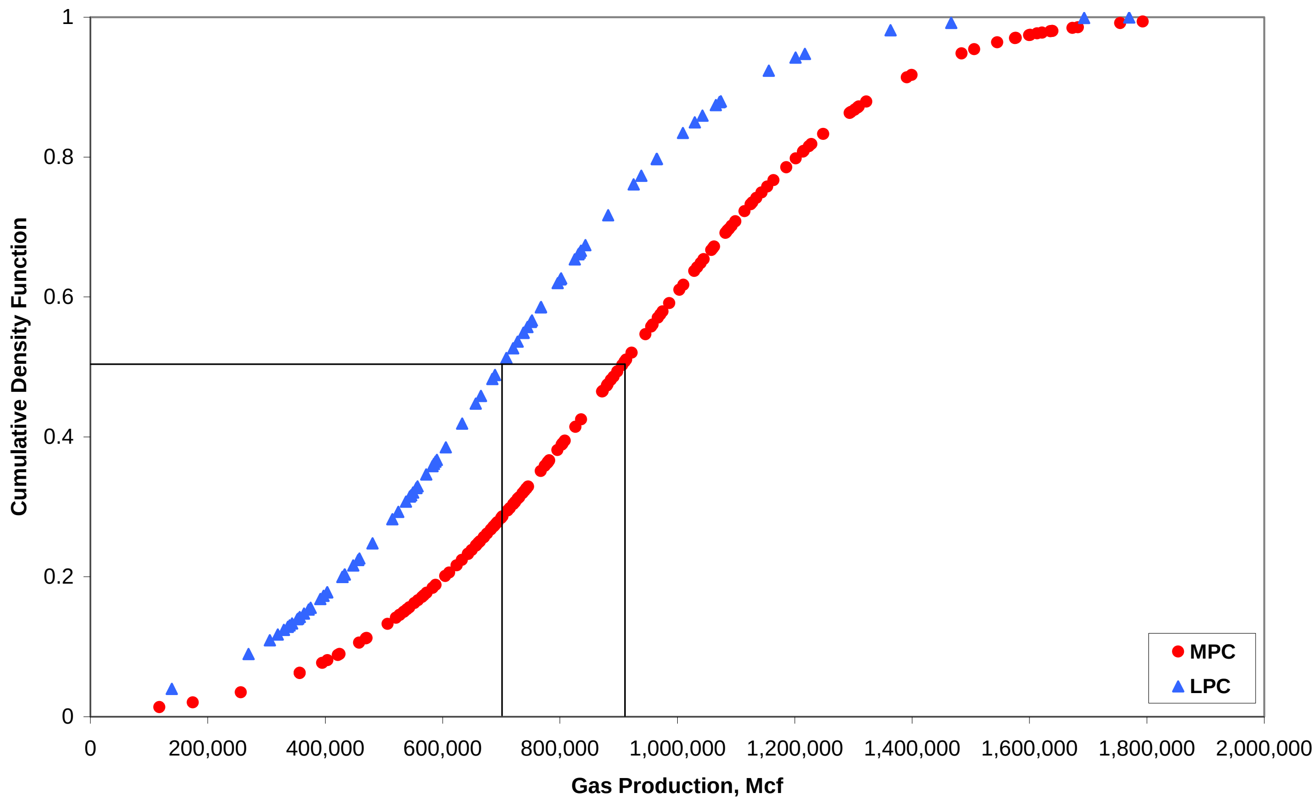


Figure 3.5—Cumulative Frequency Distribution for 3-Year Cumulative Gas Production Based on Proppant Concentration for Carthage Field. (Malpani 2006)

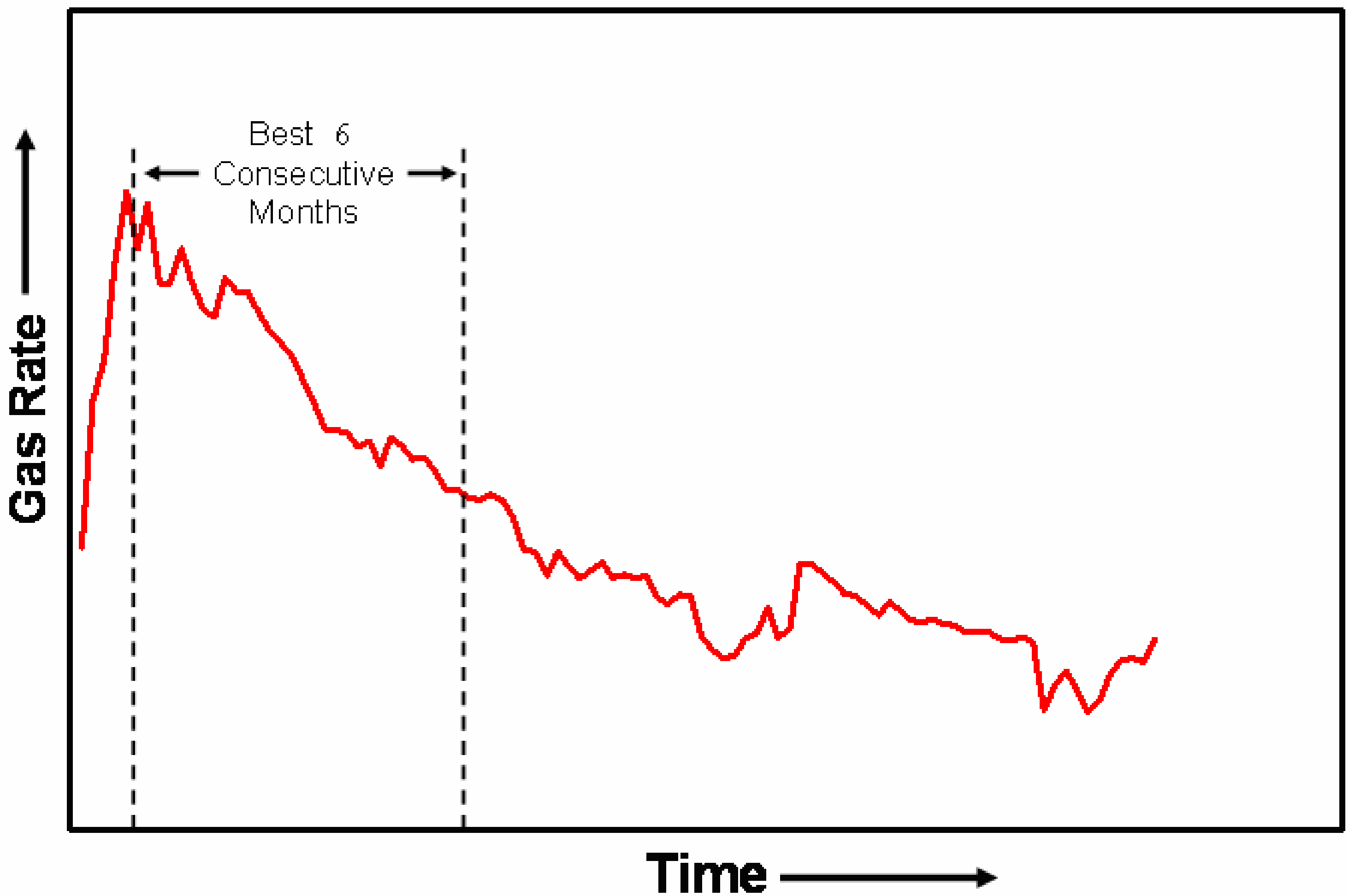


Figure 3.6—Definition of Best 6 Months Gas Production. (Hudson *et al*)

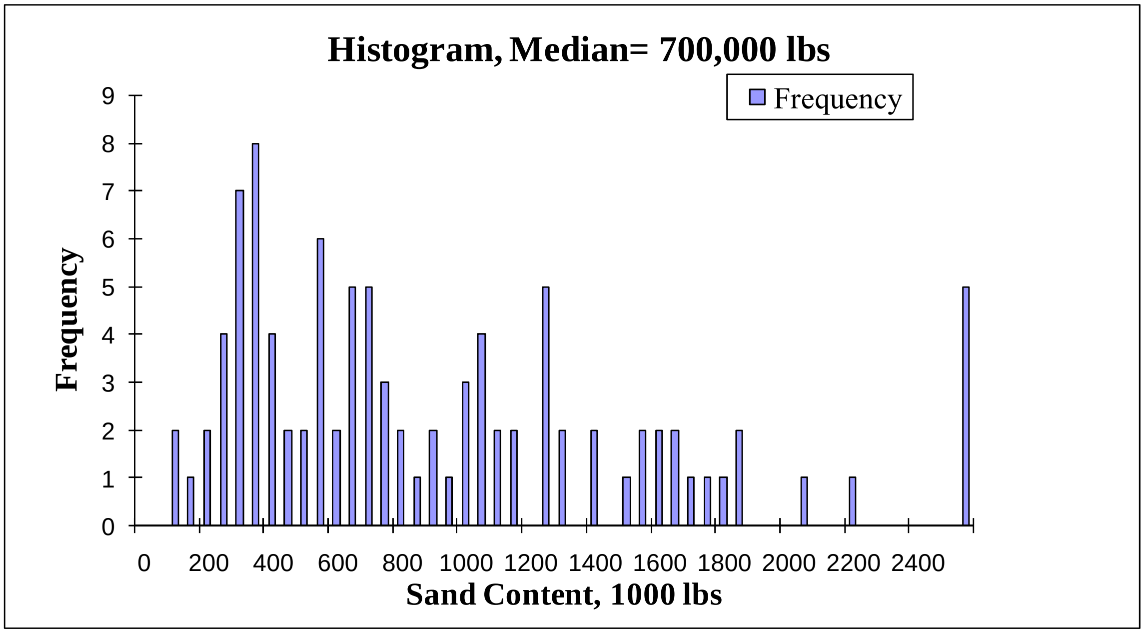


Figure 3.7—Histogram of Sand Content for the Oak Hill Field.

3.4.1 Statistical Analysis

We used statistics to evaluate which group resulted in the most gas production in the Cotton Valley sands in the Oak Hill field. We compared Best 6 Months and Best 3 Months gas production for both groups. Malpani (2006) did a similar analysis for the Cotton Valley wells in the Carthage field.

3.4.2 Hypothesis Testing

Many problems in engineering require that we decide whether to accept or reject a statement about a specific parameter. The statement is called a hypothesis and the decision making procedure concerning the hypothesis is called Hypothesis Testing. (Montgomery 2003)

Hypothesis testing procedures rely on using the information in a random sample from the population of interest. Hypothesis testing is a statistical method to compare two datasets, and it helps the investigator decide if the process or population under study is representative of the total population. Truth or falsity of a particular hypothesis can never be known with certainty, unless we can examine the entire population. Therefore, hypothesis testing procedures should be developed with the probability of reaching a wrong conclusion in mind.

Since this method can only be applied to normally distributed datasets, empirical rule needs to be applied to test the normality of the datasets. The rule suggests that if approximately 95% of the data falls between two standard deviations from mean on both sides, and approximately 99% data falls between three standard deviations from the mean on both sides then the data is normally distributed. Also, whenever a random experiment is replicated, the random variable that equals the average result over the replicate tends to have a normal distribution as the number of replicates becomes large. Hypothesis testing is based on a classic bell-shape normally distributed curve.

Parts of Hypothesis Testing (Montgomery 2003):

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 when the gas production for both data sets 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 when the gas production for both data sets was not equal].

3. The test statistic is a measure of the difference between the data and the null hypothesis, taking sampling error into account. We used the 2 sample t test to evaluate the data. We used the following test statistic:

$$T = \frac{\overline{X} - \overline{Y} - (\mu_1 - \mu_2)}{\sqrt{\frac{S_1^2}{m} + \frac{S_2^2}{n}}}$$

where $\overline{X}$ & $\overline{Y}$ are the means of the two data sets. S_1 & S_2 represents the standard deviation of the two data sets, m and n represents the degrees of freedom of the two sets.

4. The significance level (p-value) is the smallest level of significance at which the null hypothesis would be rejected. The p-value is a measure of evidence against the null hypothesis. The level of significance (α) is left to the investigator, but there are some traditional choices for confidence interval 100(1- α) %:

a. 90% is common for scientific research.

b. 95% is a choice used when more accuracy is required.

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 smaller than the level of significance (α). The t value must fall in the shaded region for the null hypothesis to be rejected at a particular level of confidence.

Comparison Using Cumulative Distribution Function (CDF) (Montgomery 2003):

In statistics, the CDF describes the probability distribution of a real-valued random variable, X. For every real number x, the CDF is given by,

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

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 follows: (for positive x values)

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

In **Fig. 3.8**, 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. Two datasets plotted on the same plot, the dataset lying on the right side of the plot has a higher value of mean than the dataset to its left. In our case, the dataset is gas production. Thus we can make a decision about which fracture treatment is better.

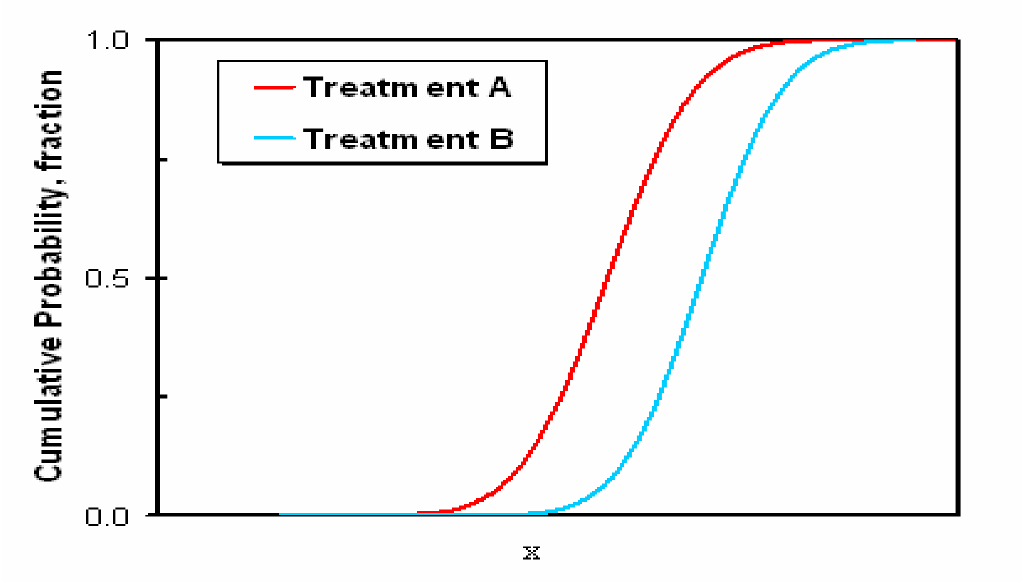


Figure 3.8—Normal Cumulative Distribution Function.

3.5 Elm Grove Field Analysis Using History Matching

We analyzed the Cotton Valley sands of the Elm Grove field operated by Matador Resources. We computed values of the permeability-thickness product, effective fracture half-length, drainage area and rectangular reservoir dimensions using gas production history matching techniques. We used an analytical simulator Promat (1999) for history matching the production data from each well. Promat is a single-layer, single phase production data analysis tool which uses a gradient based optimization technique.

3.5.1 Problems Using the Analytical Simulator (Promat)

1. History matching only production data can be a very non-unique problem. Tschirhart (2005) showed that the same field data can be matched with completely different estimates of reservoir parameters as shown in **Fig. 3.9,** when only gas production data are available.

2. Promat is a single layer model. Vera (2006) computed the error in the analyses that may occur when a multi layer reservoir is analyzed as a single layer one. He suggested that a single layer analytical simulator like Promat can only be used in a multilayer case when the permeability of each layer is similar. If the well is completed in two or more layers where one of the layers is much more permeable than the other layers, significant error in the estimates of reservoir properties may occur.
3. The following parameters can be matched using Promat; permeability, choked fracture skin, effective fracture half-length, fracture conductivity and drainage area. However, it is difficult to obtain a match while matching all the data at once. As recommended by Vera (2006) it is better to have a detailed description of the reservoir so that few of the parameters can be fixed and one only tries to compute two to three parameters during any one history match.
4. Promat can only be used for single phase analysis.
5. While forecasting gas production, Promat needs an estimate of the future flowing bottom-hole pressure values and good estimates of the ultimate well spacing.

We developed a detailed description of the Cotton Valley reservoir in the Elm Grove Field. We had reasonable estimates of fracture half-length, permeability, porosity, net pay thickness from Matador Resources for all the 25 wells matched. As suggested by Malpani (2006), we fixed the values of most of the fracture parameters (other than length) such as fracture conductivity and choked fracture skin. We matched a maximum of two parameters at a time to eliminate the match failures, keeping the other parameters fixed.

We matched only on the values of gas production and did not include the effects of water production. Production from Elm Grove field is from two layers Davis and pre-Davis, as shown in **Fig. 3.10**. The Pre-Davis is a thin and is really not very productive. Most of the gas production from the wells comes from Davis. Also, many wells in our analysis have been drilled only in the Davis formation. Hence the assumption of single layer is valid.

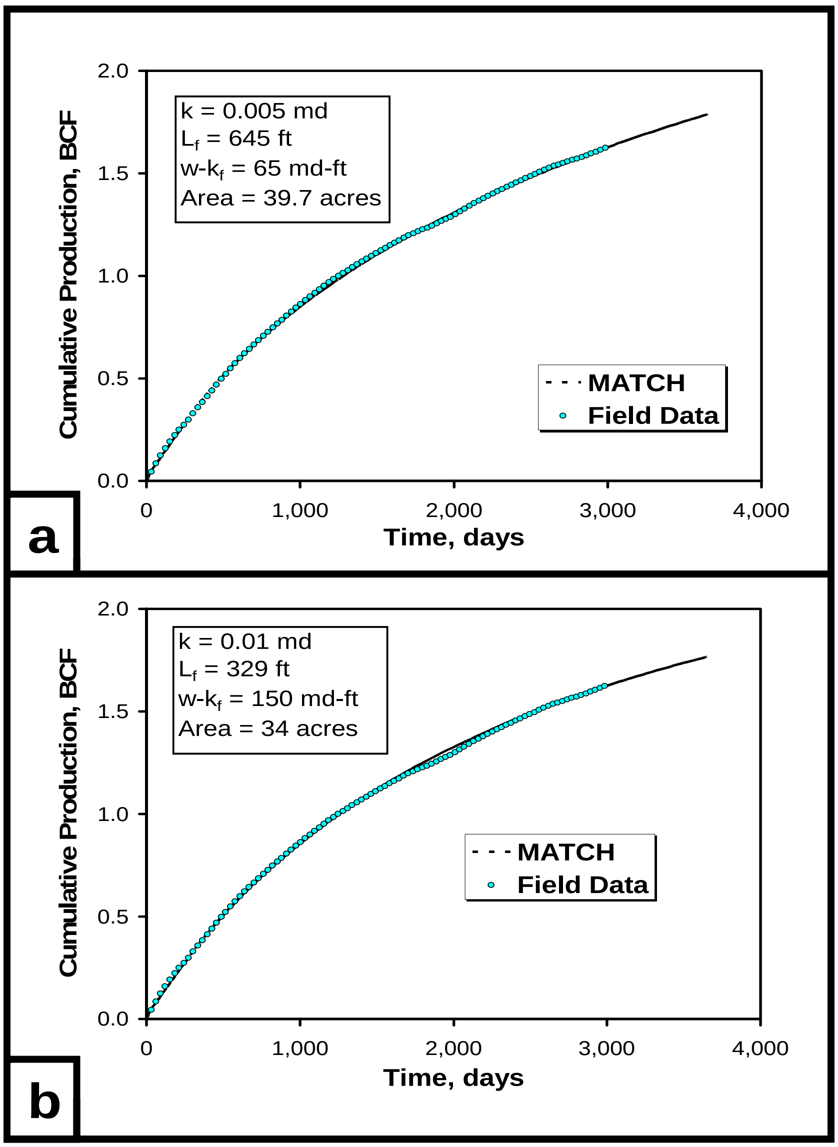


Figure 3.9—Inconclusive History Matching. (Tschirhart 2005)

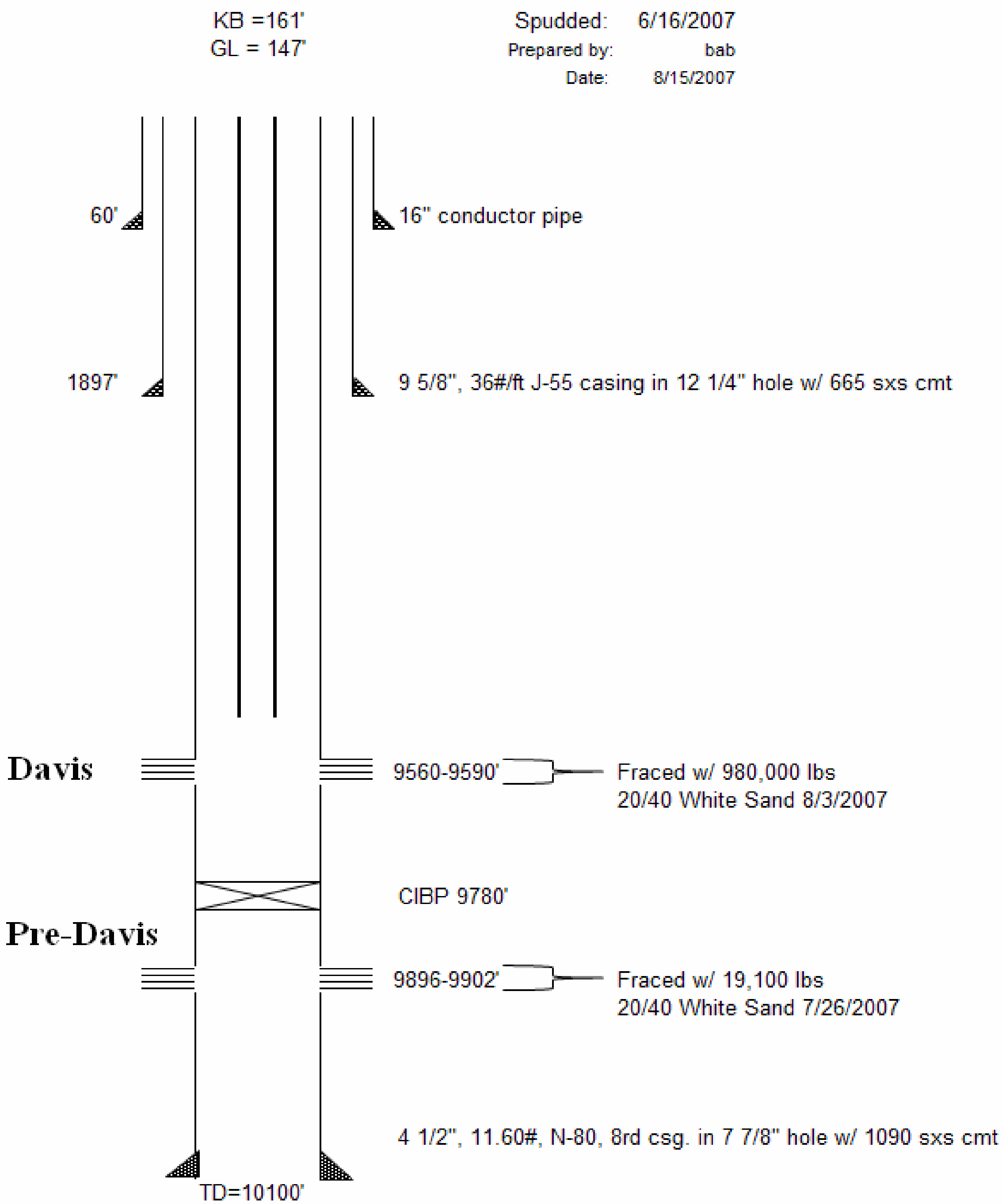


Figure 3.10—Typical Wellbore Schematic of Elm Grove Field Showing the Two Producing Layers.

Typical reservoir data and gas properties input values for Promat have been shown in Figures 3.1 and **Figure 3.11**. The values of formation temperature, porosity, net pay thickness, water compressibility and formation compressibility have been assumed to be constant for all the wells. The estimates of these values have been obtained from Matador Resources, they are accurate and can be used for initial runs. The initial reservoir pressure gradient was assumed to be 0.45 psi/ft.

We had access to the values of daily well head pressure data for all the wells. The bottom-hole pressure data has been calculated using Cullender-Smith equations (Peffer 1988). **Figure 3.12** shows the flowing bottom-hole pressure input data. Similarly, **Fig. 3.13** shows the cumulative production input values which have been computed from daily production data provided by Matador Resources. **Fig. 3.14** shows the reservoir model.

All of the parameters which can be used during a Promat history match for a well containing a hydraulic fracture are shown in **Fig. 3.15.** We had Estimated Ultimate Recovery (EUR) values for each well from Matador Resources. To estimate the drainage area, we assumed that the Original Gas in Place (OGIP) is 70% of EUR. We could then calculate the area to use in Promat from these OGIP values. Choked fracture skin and fracture conductivity were not varied. We matched on permeability and fracture half-length for each run. For calculation of the rectangular dimensions of the drainage area we assumed a 4:1 aspect ratio.

We history matched the gas production data of all 25 wells of the Elm Grove field in Cotton Valley Sands operated by Matador Resources. Typical matches of gas flow rate vs. time, gas flow rate vs. cumulative gas production and cumulative gas production vs. time have been shown in **Figures 3.16, 3.17** and **3.18** respectively. We then did a forecast of each well based on cumulative gas production as shown in **Fig. 3.19.**

Our results include computed values of permeability, fracture half-length, drainage area, drainage area dimensions, and 5 year cumulative gas production for each well in the Elm Grove field from the Promat history match. We evaluated the results from these 25 wells on the basis of where they were drilled and how they were fracture treated. We had 5 wells stimulated with water fracture treatments, 6 wells stimulated with gel fracture treatments, and 14 wells stimulated with hybrid fracture treatments. We compared the effective fracture length, drainage area, drainage dimensions, OGIP, 10 year and 5 year estimated values of cumulative gas production using means comparison and cumulative frequency curves comparison.

We also evaluated the 25 wells on the basis of where they were drilled. We divided the 25 wells into 3 regions which are labeled North (9 wells), West (7 wells) and Central (9 wells) as shown in **Fig. 3.20**. We compared the effective fracture half-length, drainage area, reservoir dimensions, permeability, permeability-thickness product (kh) using means comparison and cumulative frequency curves comparison.

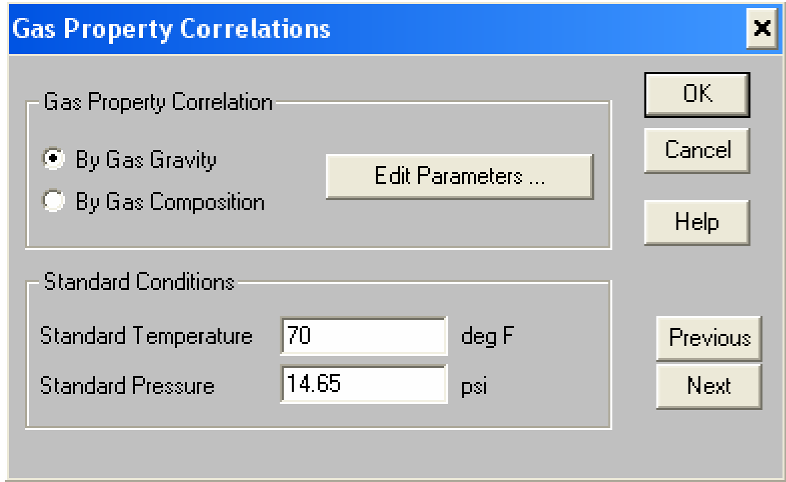


Figure 3.11—Gas Properties Data Input. (Promat)

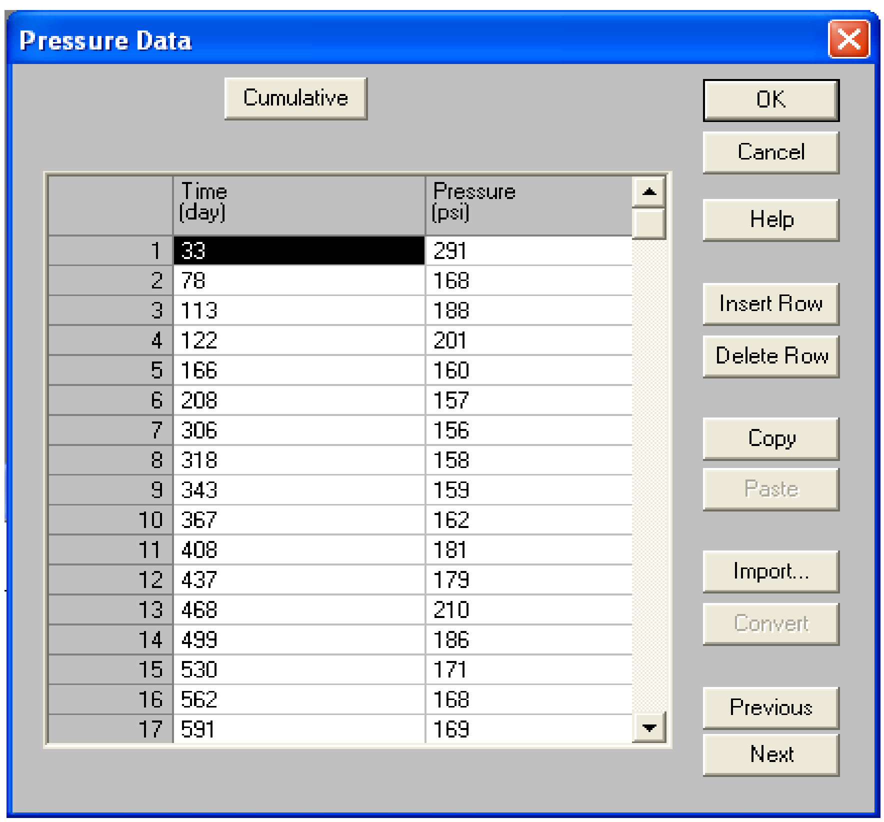
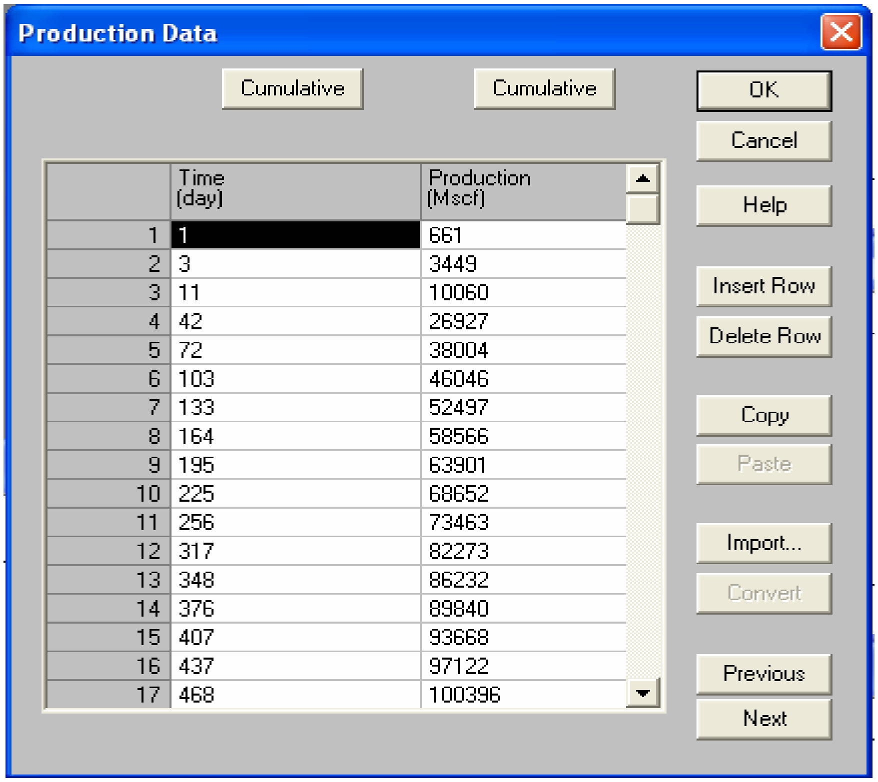


Figure 3.12—Pressure Data Input. (Promat)



	Time (day)	Production (Mscf)
1	1	661
2	3	3449
3	11	10060
4	42	26927
5	72	38004
6	103	46046
7	133	52497
8	164	58566
9	195	63901
10	225	68652
11	256	73463
12	317	82273
13	348	86232
14	376	89840
15	407	93668
16	437	97122
17	468	100396

Figure 3.13—Production Data Input. (Promat)

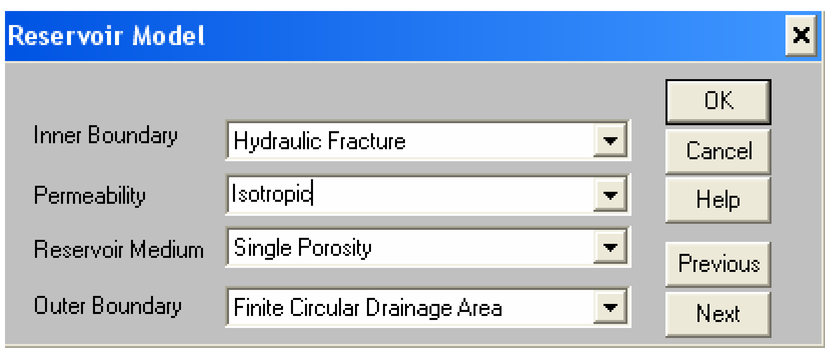


Figure 3.14—Reservoir Model Used for History Matching. (Promat)

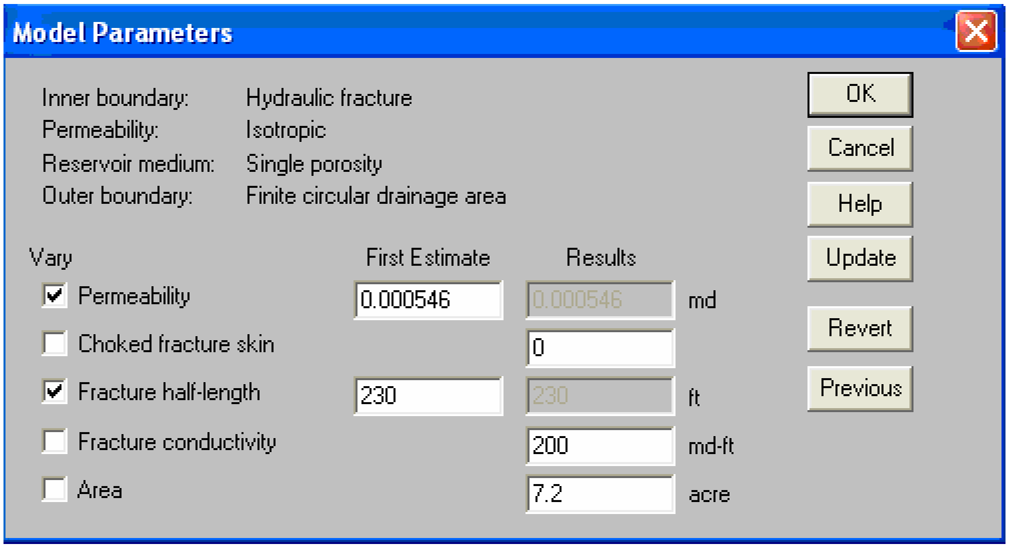


Figure 3.15—Model Parameters That Can be Varied Using History Matching. (Promat)

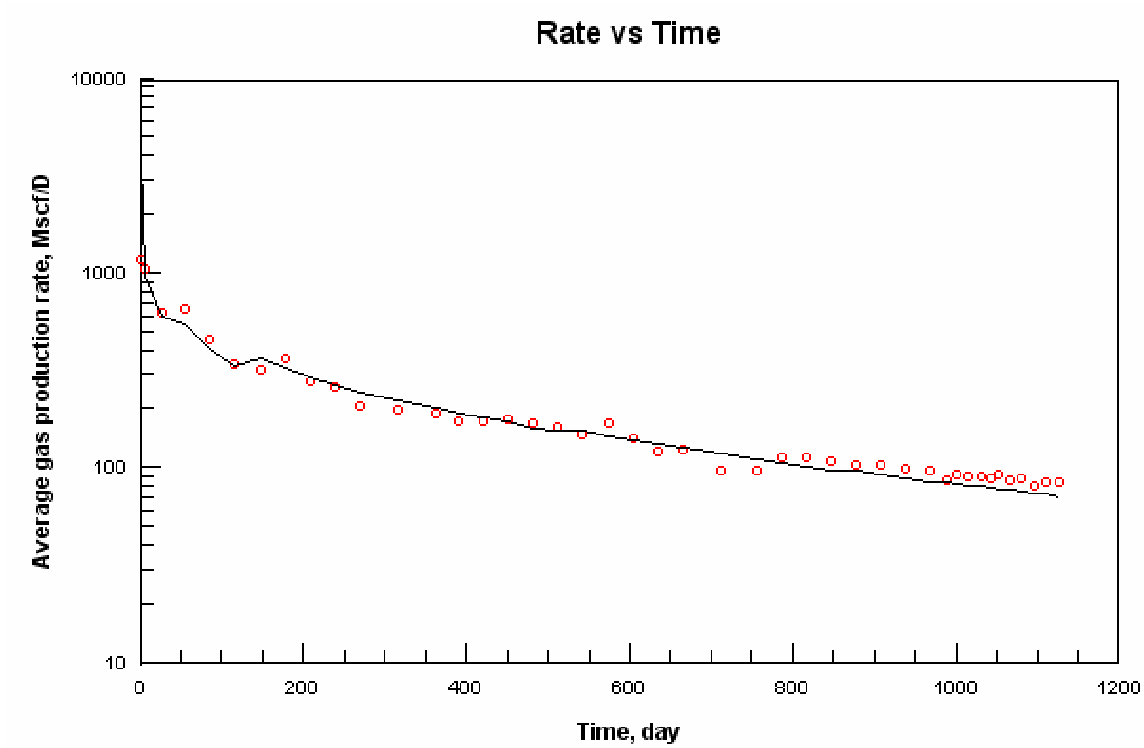


Figure 3.16— Average Gas Production Rate and Time. (Promat)

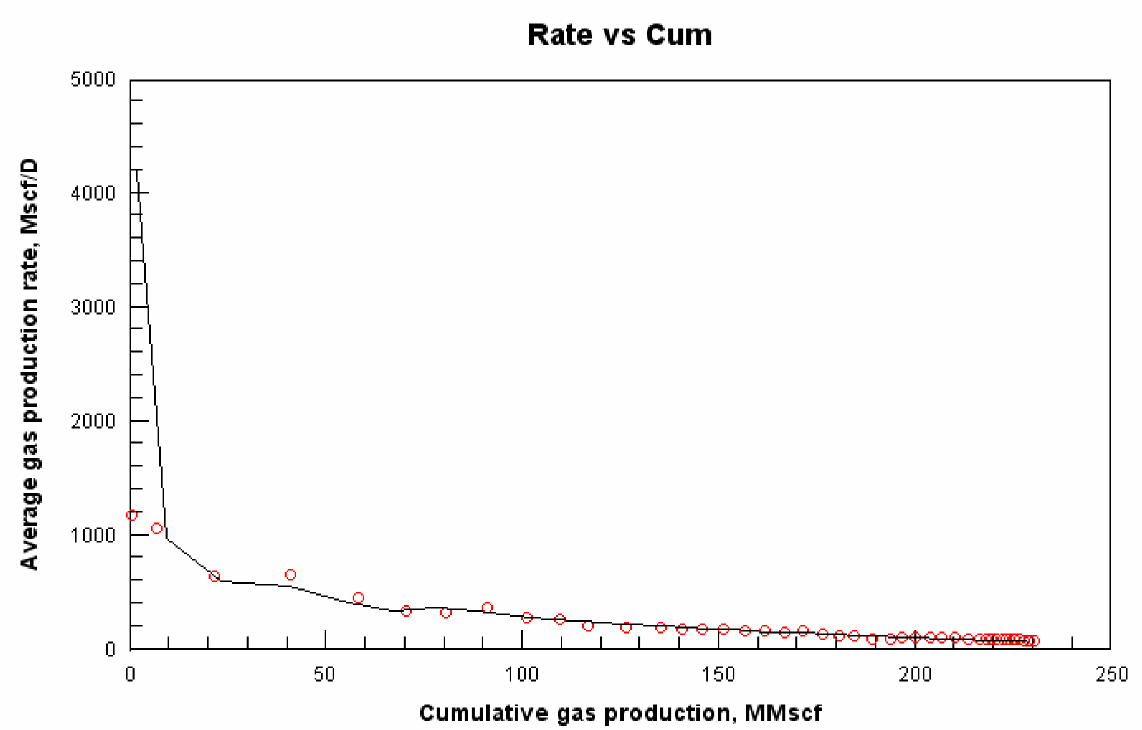


Figure 3.17— Average Gas Production Rate and Cumulative Gas Production. (Promat)

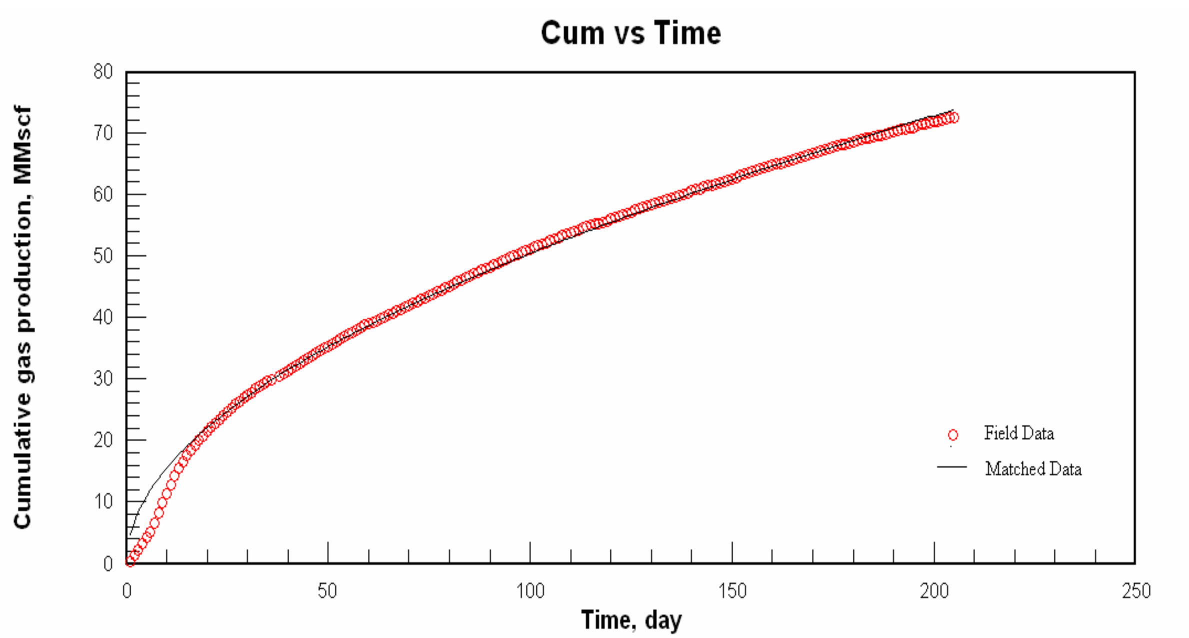


Figure 3.18—Cumulative Gas Production and Time. (Promat)

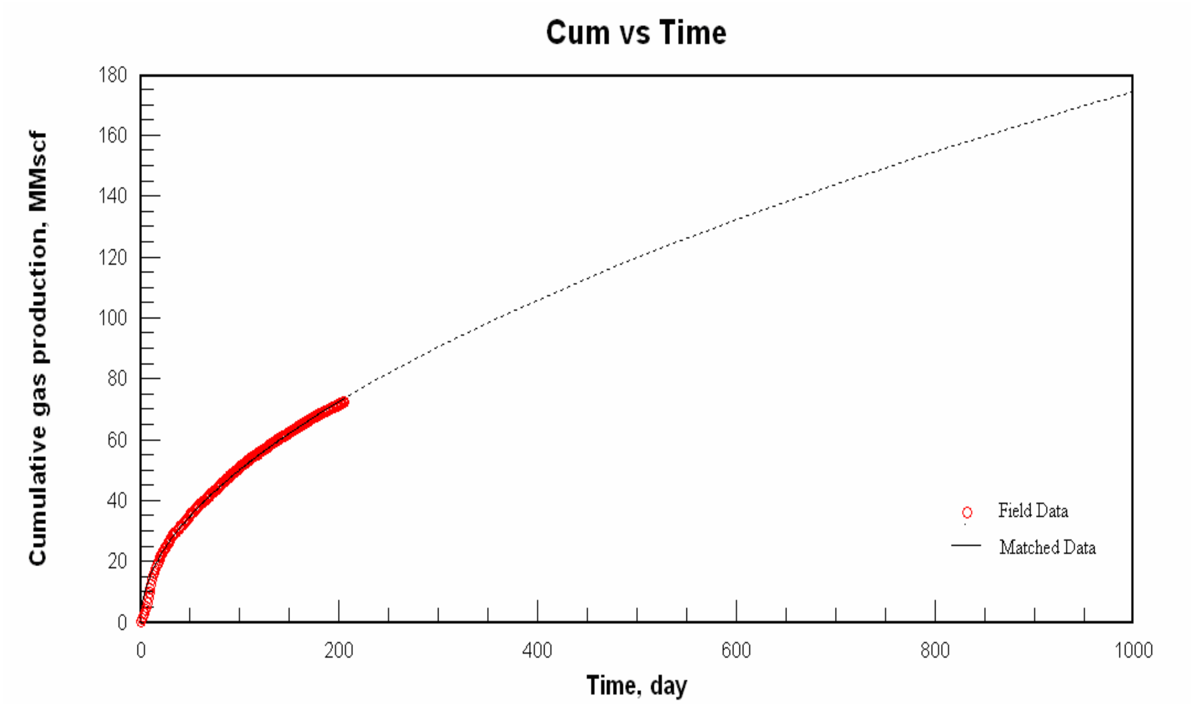


Figure 3.19—Forecasting Cumulative Gas Production. (Promat)

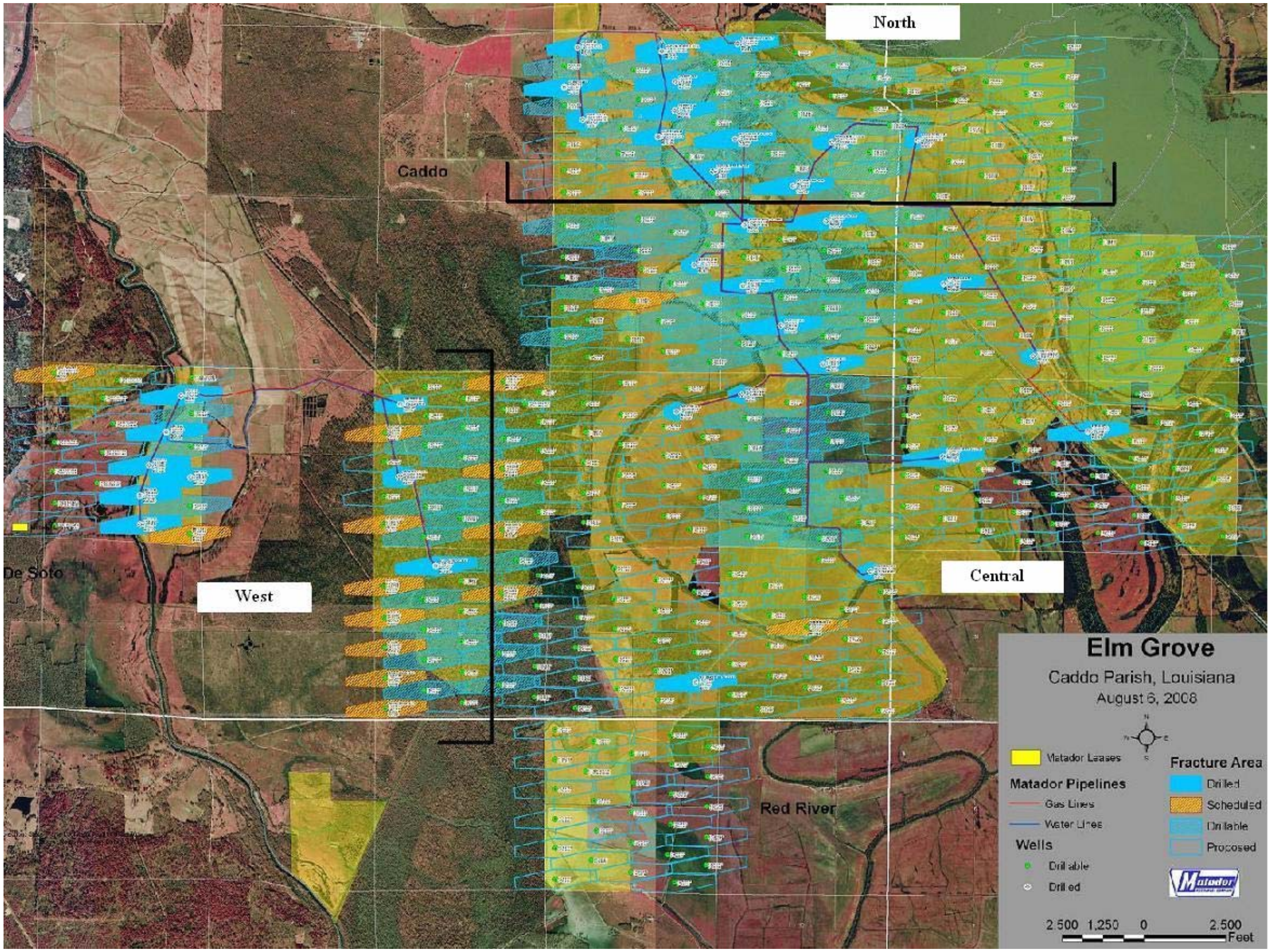


Figure 3.20—Different Regions of the Elm Grove Field Wells Drilled in the Cotton Valley Formation.

3.6 Economic Analysis of Elm Grove Field.

We performed an economic analysis the Cotton valley wells in the Elm Grove field operated by Matador Resources. We used an economic analysis software package called PHD Win (2008) to calculate the Rate of Return (ROR) for various gas prices, 5 year cumulative gas production, drilling and completion costs. We did this analysis to compare the three different fracture treatments on the basis of revenue.

Data setup for PHD Win:

On the basis of our history match results, we selected values for 5-year cumulative gas production that appear to be realistic for the portion of the Elm Grove Field being drilled by Matador Resources. These values were; 100, 250, 400, 550 and 700 MMcfe. We used Arps decline curve equation which is put of the PHDWin software to develop a gas flow rate vs. time schedule for each case. Arp's equation is given by:

$$Q = Q_i (1 + bD_i t)^{(-1/b)}$$

where

Q = rate at time, t, Mscf/d

Qi = Initial rate. Mscf/d

b = Hyperbolic exponent.

Di = Initial Nominal decline rate, 1/time or %/year

We matched typical Elm Grove production data from a well with an Arps equation in PDH Win as shown in **Fig. 3.21**. To obtain different 5 year cumulative gas production values we changed the b and Qi of each Arps curve and used PHD Win to generate the gas production rate schedule. We used a b value of 1.63 for wells with 5 year cumulative gas production of 100 and 250. We used a b value of 1.77 for wells with higher values of 5 year cumulative gas production. We used a constant De value of 100% decline /year. We then set up the pricing tab for the following gas prices; \$6, \$7, \$8, \$9, \$10 and \$12 /MMBtu.

We then ran economic analysis computer runs for a fixed gas price and fixed D&C cost for each of the five production schedules. The output report for a 400 MMcfe 5 year cumulative gas production curve at a gas price of \$8 /MMBtu, and D&C cost of \$1.4 Million is shown in **Fig. 3.22.** The ROR value is circled in the figure. We then calculated the ROR for all combinations of gas price and D&C costs and from tables for comparison and plot graphs of ROR vs. Gas price and ROR vs. D&C costs.

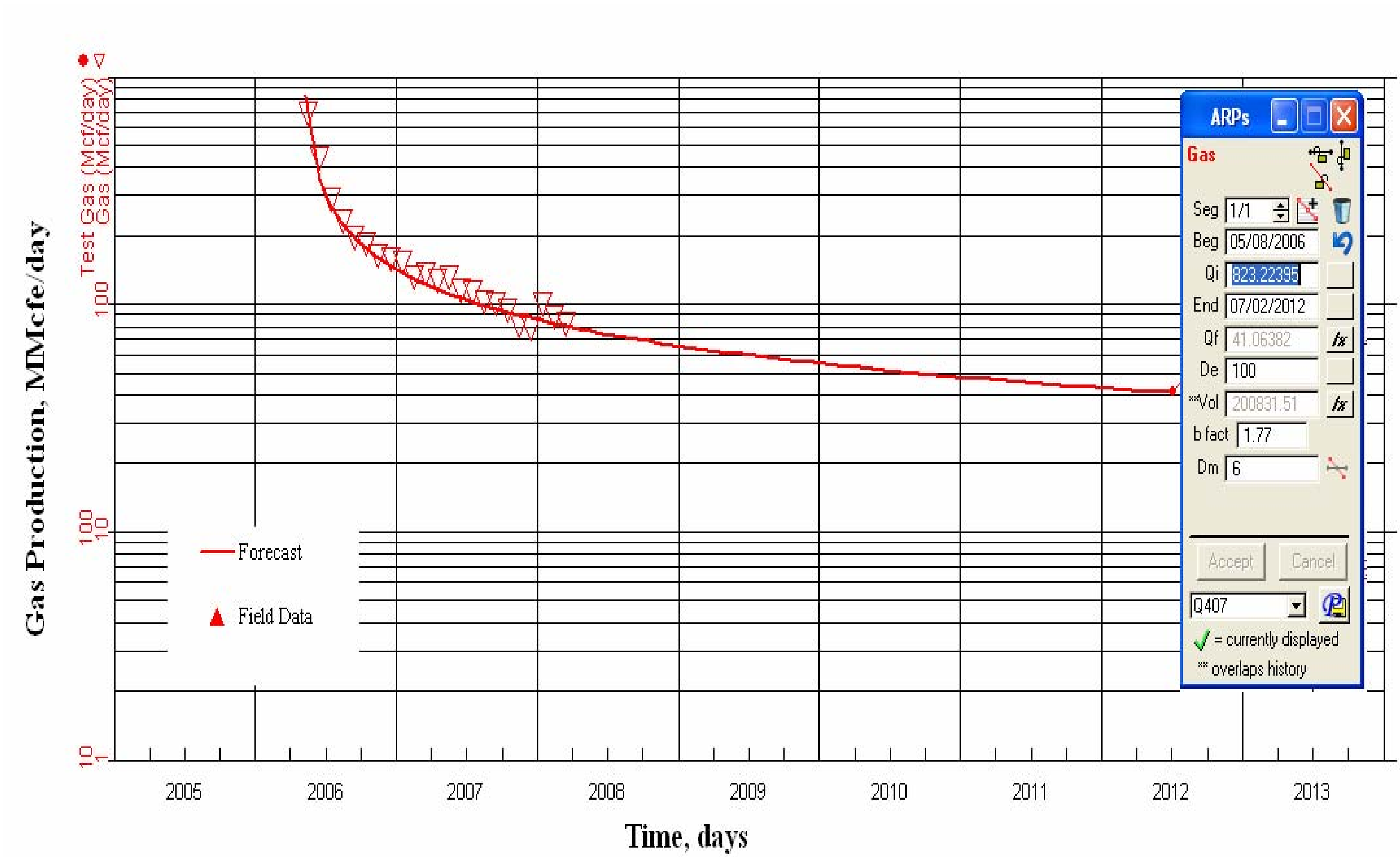


Figure 3.21—Field Data of Typical Well in the Elm Grove Field Forecasted with Arps Curve with Matched Parameters.

Date : 9/5/2008 6:27:29AM
Partner : All Cases
Retrieval Code :
Reserve Cat. : Typical Well Undeveloped
Location : SEC 14 - 15N - 12 W
Archive Set : MRC Q4 2007

ECONOMIC PROJECTION

CY06 Reserve Projections
TYPICAL ELM GROVE SENS 03 400
Discount Rate : 10.00
As of : 1/1/2008

Gas: $8.00/MMBtu. Base -25% LOE

Case : TYPICAL ELM GROVE SENS 03400
Type : LEASE CASE
Field : ELM GROVE
Operator : MATADOR PRODUCTION CO.
Reservoir : COTTON VALLEY
Co., State : CADDO, LA
API No. :

Est. Cum Oil (Mbbl) : **0.00**
Est. Cum Gas (MMcf) : **0.00**
Est. Cum Water (Mbbl) : **0.00**

Year		Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2008		0.00	174.17	0.00	134.98	0.00	7.13	962.36	0.00	102.31	33.51	1,400.00	-573.46	-603.67
2009		0.00	79.29	0.00	61.45	0.00	7.13	438.11	0.00	51.46	15.25	0.00	371.40	-282.74
2010		0.00	59.23	0.00	45.91	0.00	7.13	327.28	0.00	40.70	11.40	0.00	275.18	-67.75
2011		0.00	48.99	0.00	37.97	0.00	7.13	270.71	0.00	35.22	9.43	0.00	226.07	92.05
2012		0.00	42.64	0.00	33.05	0.00	7.13	235.62	0.00	31.81	8.20	0.00	195.60	217.17
Rem.		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**5.0**	**0.00**	**404.34**	**0.00**	**313.36**	**0.00**	**7.13**	**2,234.07**	**0.00**	**261.50**	**77.79**	**1,400.00**	**494.79**	**217.17**
Ult.		**0.00**	**404.34**											

Major Phase :	Gas		
Initial Rate :	47,271.12	Mcf/month	
Abandonment :	3,336.98	Mcf/month	
Initial Decline :	100.000	%/year	b = 1.77
Initial Ratio :	0.000	bbl/Mcf	
Abandon Ratio :	0.000	bbl/Mcf	
Abandon Day :	12/31/2012		

Eco. Indicators

Return on Investment (disc) :	1.155
Return on Investment (undisc) :	1.353
Years to Payout :	2.72
Internal Rate of Return (%) :	20.49

	Initial	1st Rev.	2nd Rev.
Working Interest :	1.00000000	0.00000000	0.00000000
Revenue Interest :	0.77500000	0.00000000	0.00000000
Rev. Date :			

Present Worth Profile (M$)

PW 0.00 % :	**494.79**	**PW 13.00 % :**	**148.33**
PW 5.00 % :	**345.81**	**PW 20.00 % :**	**8.16**
PW 9.00 % :	**241.44**	**PW 30.00 % :**	**-152.35**
PW 10.00 % :	**217.17**	**PW 50.00 % :**	**-378.34**
PW 12.00 % :	**170.64**	**PW 100.00 % :**	**-672.54**

Figure 3.22—Economic Projection of a Well Producing 400 MMcfe of Gas for 5 Years at a Gas Price of $8 /MMBtu and D&C Costs of $1.4 Million.

CHAPTER IV

RESULTS AND DISCUSSIONS

4.1 Data Analysis of Oak Hill Field

4.1.1 Statistical Analysis using Hypothesis Testing

Table 4.1 shows the comparison of the means and standard deviation of the field gas production data. Group I are the wells with bottom-hole pressure (BHP) greater than 3500 psi and Group II are the well with BHP less than 3500 psi. High Sand Content (HSC) wells have sand content greater than 700,000 lbs. And Medium Sand Content (MSC) wells have sand content less than 700,000 lbs.

Hypothesis testing was done for the following data sets based upon the values of best 6 months gas production. Since the data sets used should be normally distributed for hypothesis testing, the empirical rule was used to test normality as shown in **Table 4.2**.

Table 4.1—Data for Hypothesis Testing Based on Best 6 Months Gas Production of Oak Hill Field.

Gas Production Best 6 months	Group I		Group II	
	HSC	MSC	HSC	MSC
Mean, Mcf/month	30,095	21,559	26,588	19,484
Standard Deviation	8,963	6,665	9,392	6,716
Data Points	25	22	29	23

Table 4.2—Data for Testing Normality for Best 6 Months Gas Production. (Oak Hill)

Gas Production Best 6 months	Group I		Group II	
	HSC	MSC	HSC	MSC
Mean ± 2 Std. Dev. (%)	96	95	100	100
Mean ± 3 Std. Dev. (%)	100	100	100	100

All datasets qualified using the Empirical rule hence they are normally distributed.

Hypothisis:

Null hypothesis: H_0: $\mu_1 = \mu_2$ Means are equal for both data sets.

Research hypothesis: H_1: $\mu_1 \neq \mu_2$ Means are unequal for both data sets.

Table 4.3—Results of Hypothesis Testing Based upon Best 6 Months of Gas Production.

Parameter	**Values**	
	Group I	**Group II**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.0005	0.0094

From the results shown in **Table 4.3,** we reject the null hypothesis with 95% confidence because p-value is less than rejection criterion, α. This implies that the mean gas production for HSC and MSC are unequal. Also, **Fig. 4.1** indicates that HSC has better mean than MSC for both the groups. We also did the same hypothesis testing based upon Best 3 Months (Appendix A).

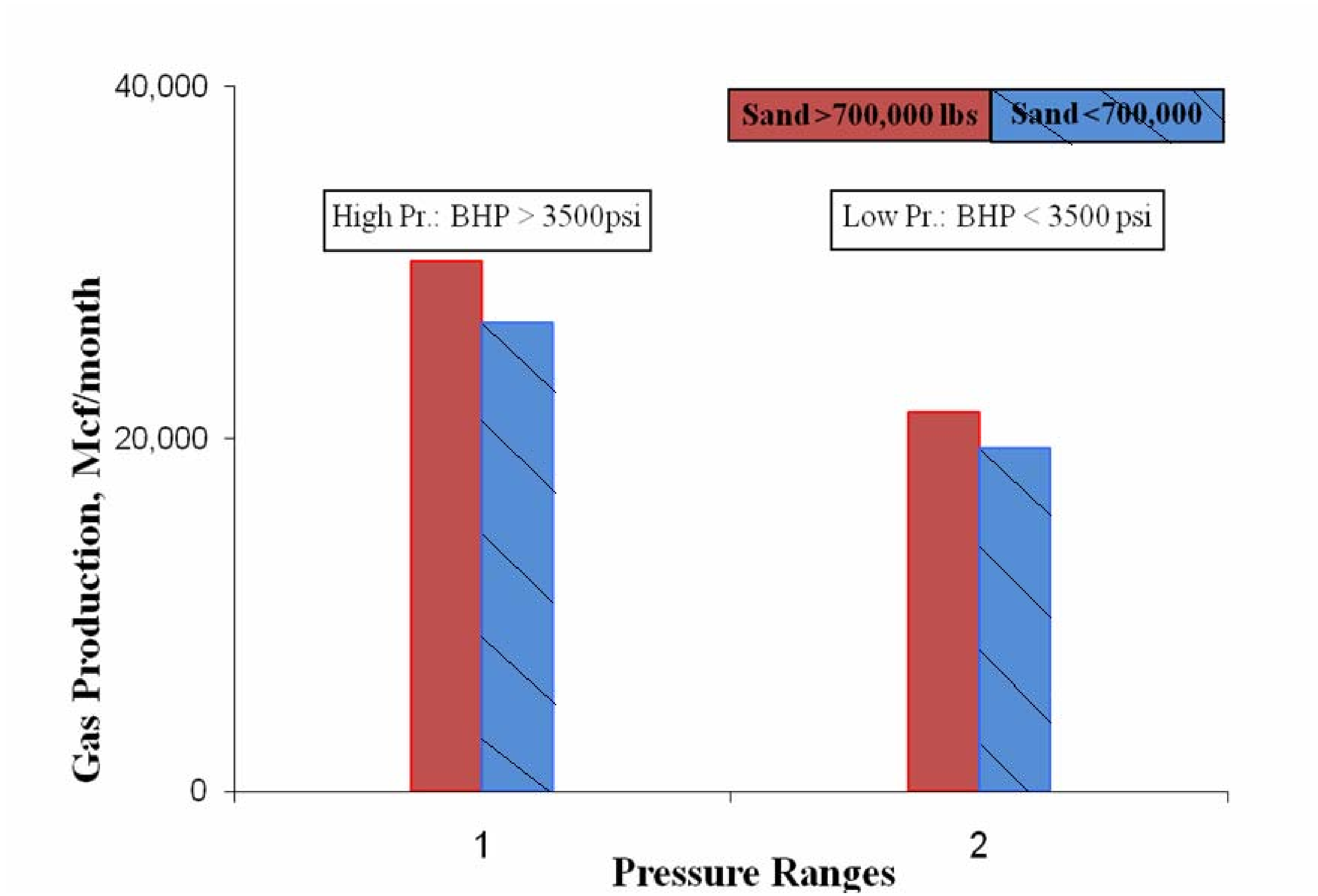


Figure 4.1—Comparison of Gas Best 6 Months Production for Wells in Oak Hill Field.

4.1.2 Analysis Using Cumulative Distribution Curves Comparison

In **Fig. 4.2**, we plotted the cumulative distribution function versus the best 6 months gas production for both HSC and MSC for all the wells. On average, the HSC wells had more gas production than the MSC wells during the first 6 months. This indicates that gas production performance of the wells depends upon the amount of sand used during the fracture treatments for the wells. We also plotted the cumulative distribution function versus the best 6 months of gas production for the HSC wells for both group I and group II wells in **Fig. 4.3**. On average, the wells in group I produces more gas than the wells in group II. This indicates the production performance of these wells is directly dependent on initial reservoir pressure of the wells. So we can conclude that the high pressure wells are better than the low pressure wells. All the above results were comparable with the work done by Malpani (2006) on the Cotton Valley sands of Carthage field.

Fig. 4.4 is a plot of cumulative distribution function for best 6 months gas production for both pressure groups and both sand content. We also plotted similar cumulative distribution curves for Best 3 Months gas production (refer to appendix B). Group I HSC wells are on the right side of Group I MSC wells and Group II HSC wells are on the right side of the Group II MSC wells. This indicates HSC wells are better as they yield more gas production**.** Malpani (2006) did the similar analysis on Cotton Valley sand of the Carthage field and published the data shown in **Fig. 4.5**. He suggested that Group II MPC wells and Group I LPC wells cumulative distribution curves are lying on top of each other and hence lower pressure MPC wells are as good as higher pressure LPC wells.

However, in our analysis of the Oak hill field shown in Fig. 4.4, Group II HSC wells and

Group I MSC wells do not overlay each other. Our study indicates that the Group II HSC wells are to the right of Group I MSC wells. So we cannot come to a conclusion by analyzing just one field that both Group II HSC and Group I MSC are comparable.

4.2 Data Analysis of Elm Grove Field

4.2.1 Analysis by Treatment Type

Table 4.4 show the output values from the history match of the gas production for five wells that were stimulated using water fracture treatments. Promat was used to compute the values in Tables 4.4 to 4.6. Even thought the matches are not necessarily unique the methodology employed was consistent and enough runs were made to allow us to believe the comparison of the results in Tables 4.4 to 4.6 are valid. **Table 4.5** shows the history match results for the 6 wells treated with gel fracture treatments. The results for the 14 wells treated with hybrid fracture treatments are presented in **Table 4.6**.

Table 4.7 is a summary of all the three fracture treatment types. **Fig. 4.6** is a plot of fracture half-length for various treatment types. We observe that the water fracture treatments have the smallest fracture half-length and the hybrid fracture treatments have the longest fracture half-lengths. We also observe that the fracture half-lengths of gel and hybrid fracture treatments are comparable. Similarly **Figs. 4.7** and **4.8** are the plots of drainage area and the reservoir dimensions for each treatment respectively; we observe a similar increasing trend from water to gel fracture treatment. We can conclude that the effective fracture half-length, drainage area and the reservoir dimensions depend on the type of fracture treatment used to stimulate the well.

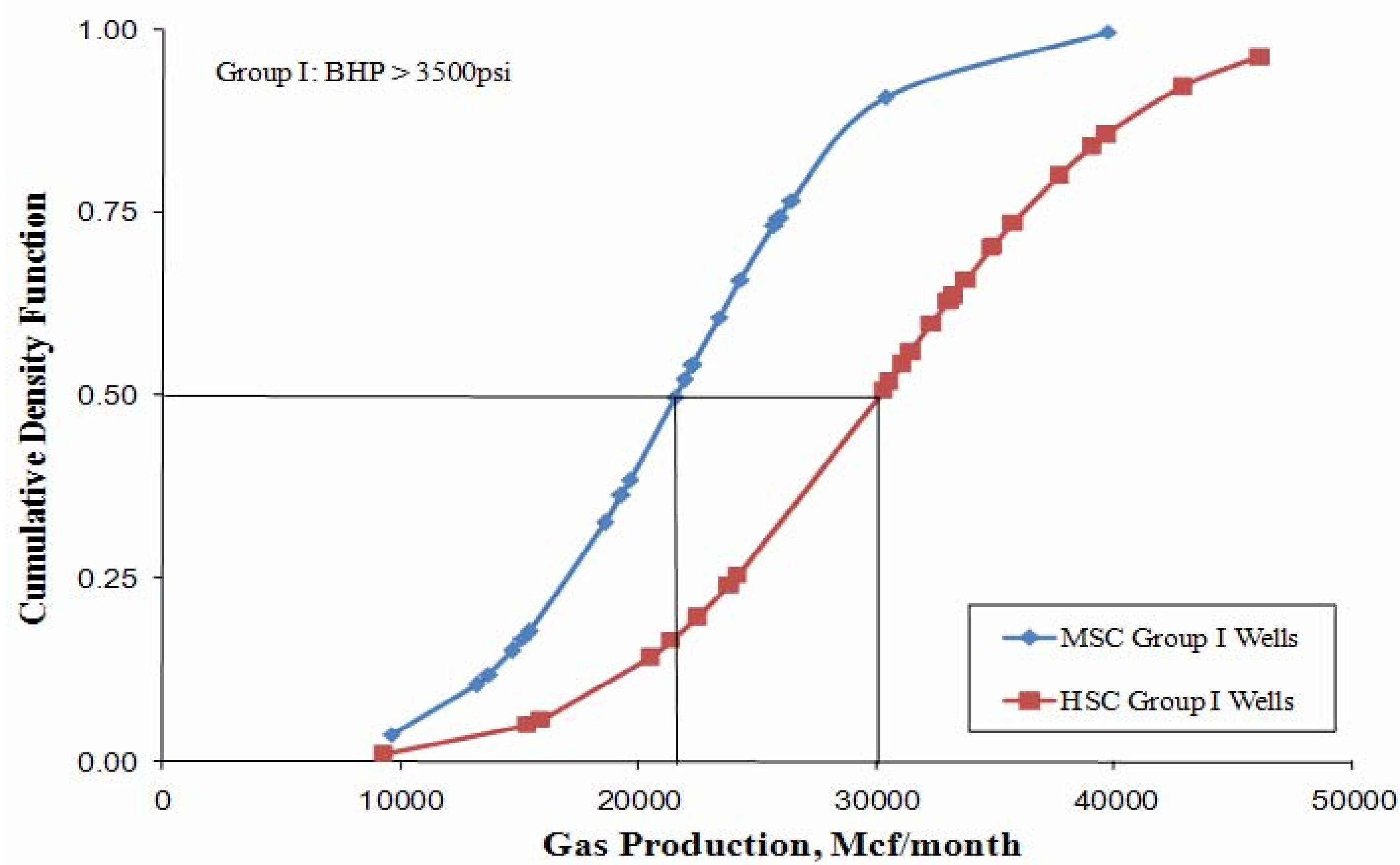


Figure 4.2—CDF for Gas Best 6 Months Production Based on Sand Content. Indicates Wells with Higher Sand Content Produce Better.

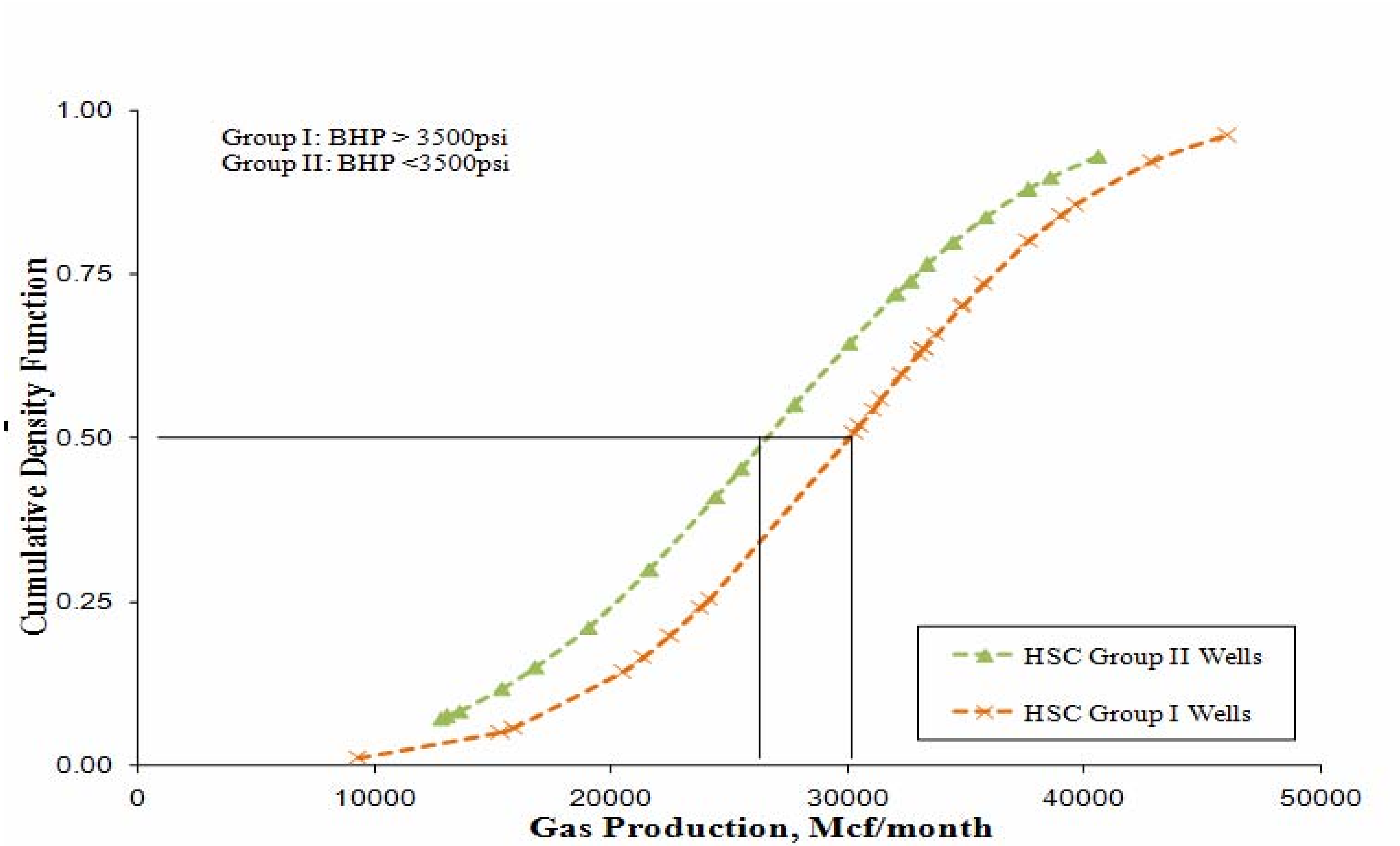


Figure 4.3—CDF for Gas Best 6 Months Production Based on Initial Pressure for HSC Wells. Indicate High Pressure Wells give Better Production.

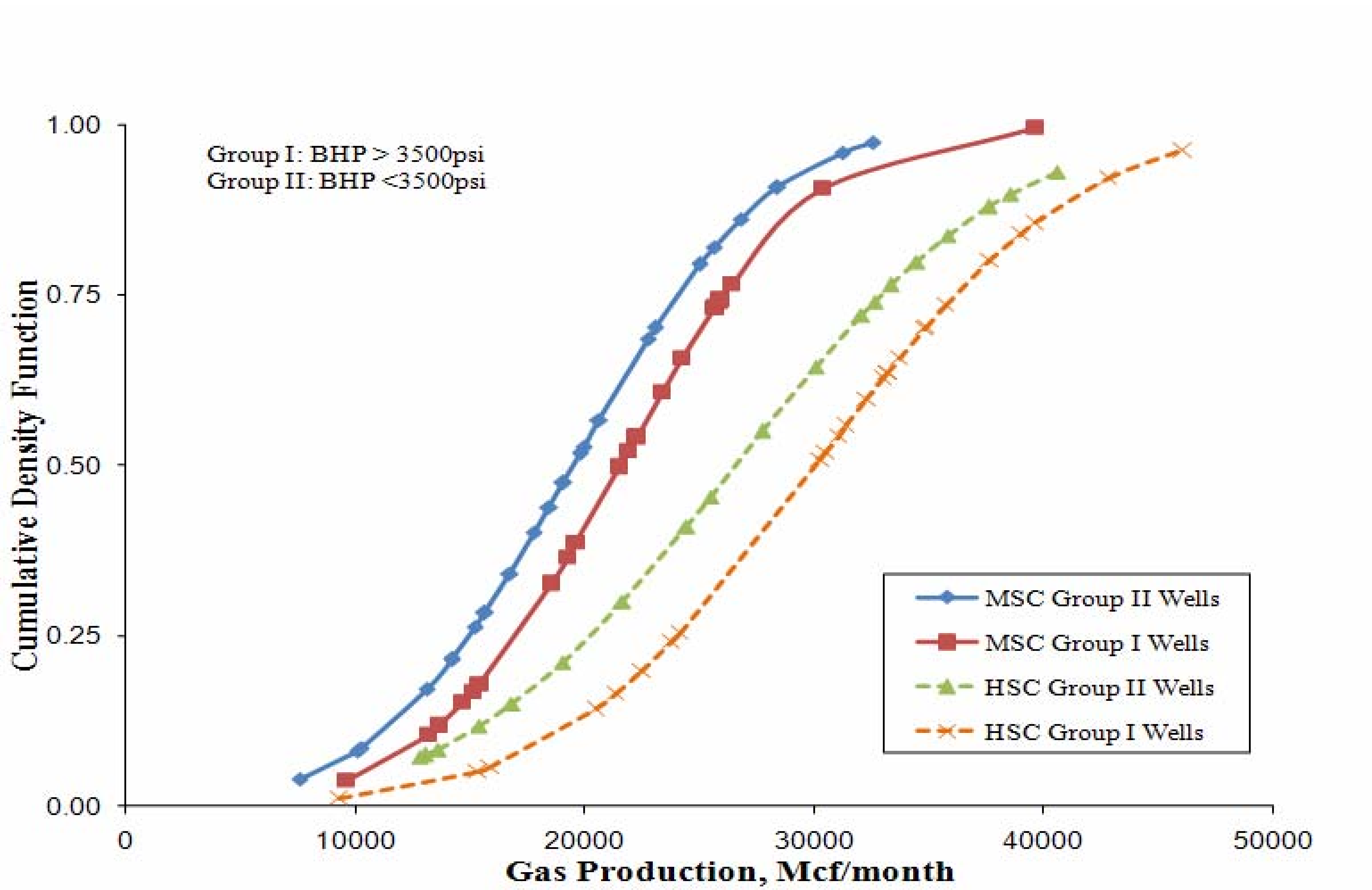


Figure 4.4—CDF for Gas Best 6 Months Production for Both Groups and Both Sand Content. (Oak Hill)

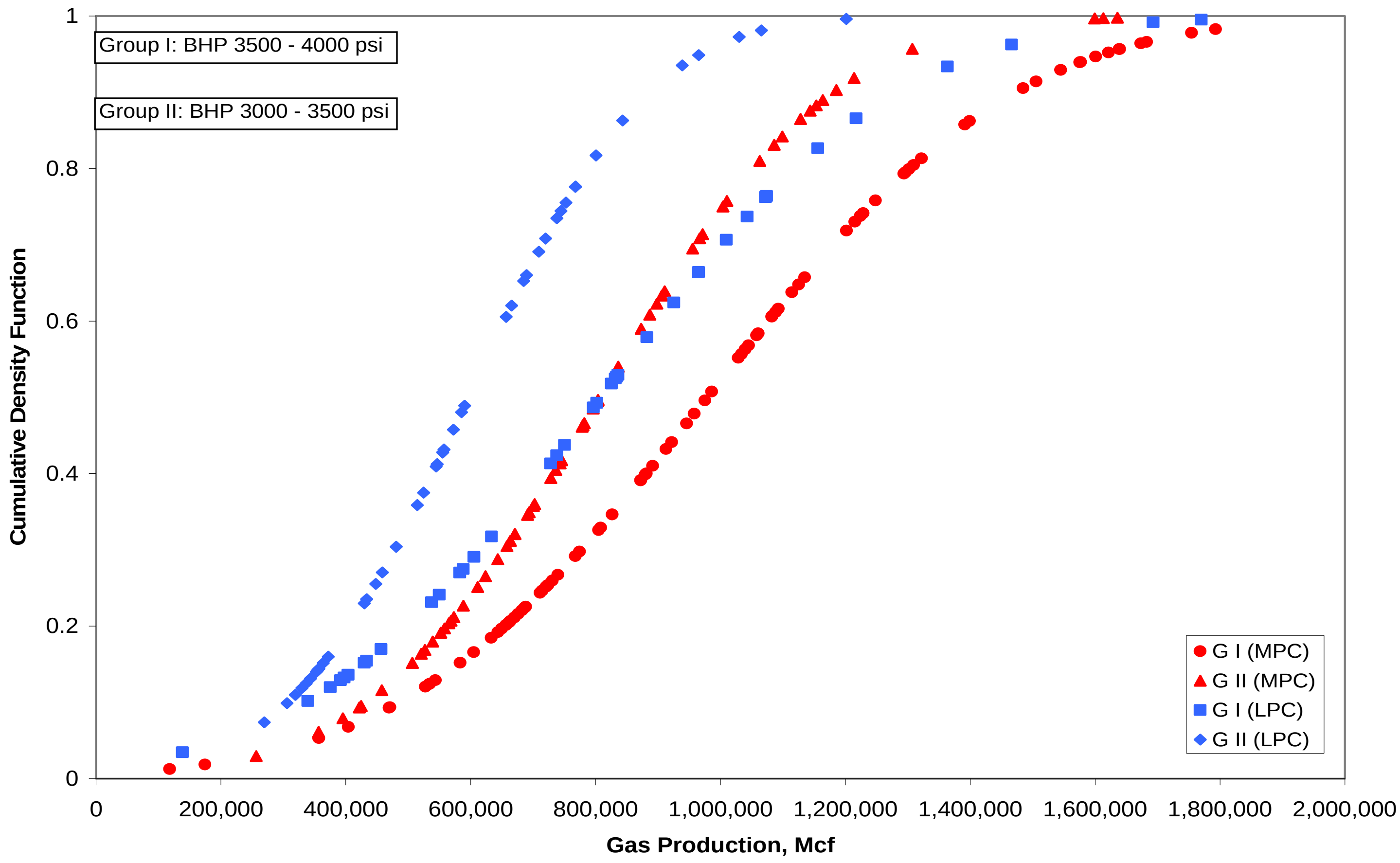


Figure 4.5—CDF for 3-Year Cumulative Gas Production for Both Groups and Both Treatments for the Carthage Field. (Malpani, 2006).

Table 4.4—Output Data for Water fracture Treated Wells in Elm Grove Field.

Well No.	Permeability-thickness, mD-ft	Fracture Half-Length , ft	Drainage Area, Acre	Sand Content, lb/gal	Reservoir Length, ft	Reservoir Width, ft
1	0.216	144	2.3	0.60	626	157
2	0.293	120	2.2	0.68	619	155
3	0.271	183	2.5	0.67	665	166
4	0.090	230	7.2	0.88	1120	280
5	0.205	180	10.6	0.67	1359	340

Table 4.5— Output Data for Gel Fracture Treated Wells.

Well No.	Permeability-thickness, mD-ft	Fracture Half-Length , ft	Drainage Area, Acre	Sand Content, lb/gal	Reservoir Length, ft	Reservoir Width, ft
1	0.047	286	6.2	1.03	1039	260
2	0.079	326	8.1	1.15	1188	297
3	0.081	315	10.3	1.40	1340	335
4	0.236	265	5.3	1.14	964	241
5	0.143	230	11.7	0.92	1428	357
6	0.306	308	7.2	1.54	1120	280

Table 4.6— Output data for Hybrid Fracture Treated Wells.

Well No.	Permeability-thickness, mD-ft	Fracture Half-Length , ft	Drainage Area, Acre	Sand Content, lb/gal	Reservoir Length, ft	Reservoir Width, ft
1	0.050	208	3.3	1.01	758	190
2	0.066	230	5.5	0.99	974	244
3	0.073	328	8.2	1.19	1195	299
4	0.076	344	9.0	1.69	1252	313
5	0.095	342	8.9	1.55	1245	311
6	0.088	366	10.2	1.59	1333	333
7	0.104	375	10.8	1.83	1372	343
8	0.093	400	13.7	1.88	1545	386
9	0.132	370	10.4	1.82	1346	337
10	0.464	160	18.9	1.43	1815	454
11	0.200	340	16.2	1.59	1680	420
12	0.555	348	20.8	1.45	1904	476
12	0.387	271	13.9	1.27	1556	389
14	0.495	249	22.8	1.55	1993	498

Table 4.7—Summary of the Wells, by Treatment Type.

Treatment type	Permeability-thickness, mD-ft	Fracture Half-Length , ft	Drainage Area, Acre	Sand Content, lb/gal	Reservoir Length, ft	Reservoir Width, ft
Water Fracture	0.215	171	5.0	0.7	878	219
Gel Fracture	0.149	288	8.1	1.2	1180	295
Hybrid Fracture	0.206	309	12.3	1.5	1426	357

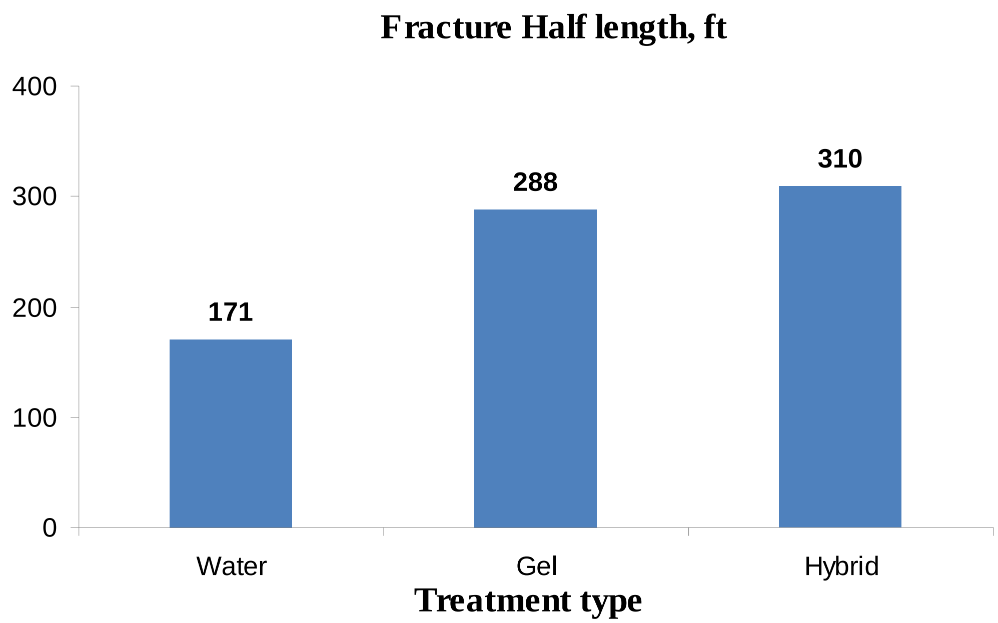


Fig. 4.6—Comparison of the Average Estimated Fracture Half-Length Based on Treatment type for Wells in the Elm Grove Field.

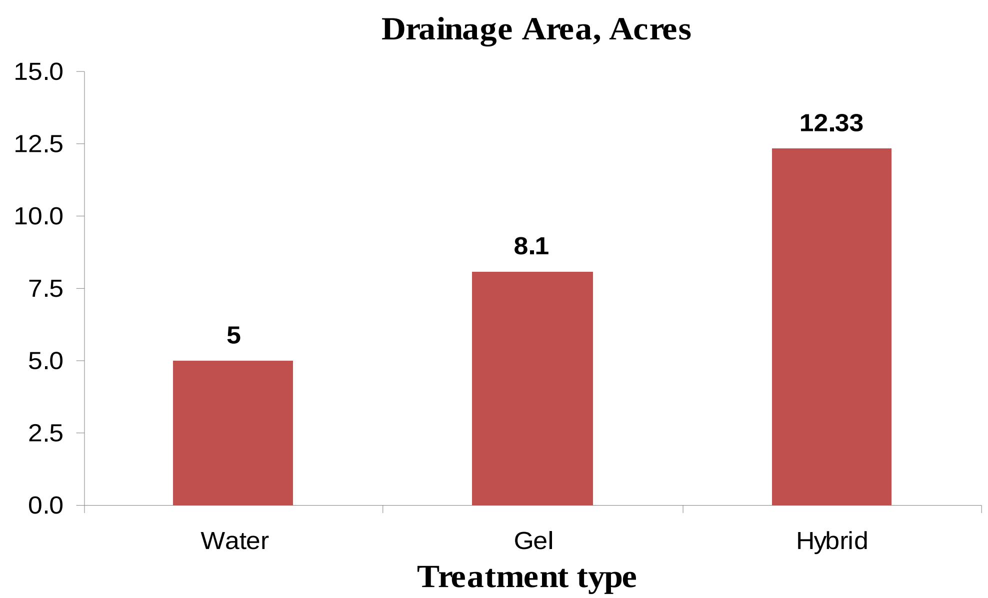


Fig. 4.7— Comparison of Average Estimated Drainage Area Based on Treatment Type. (Elm Grove field)

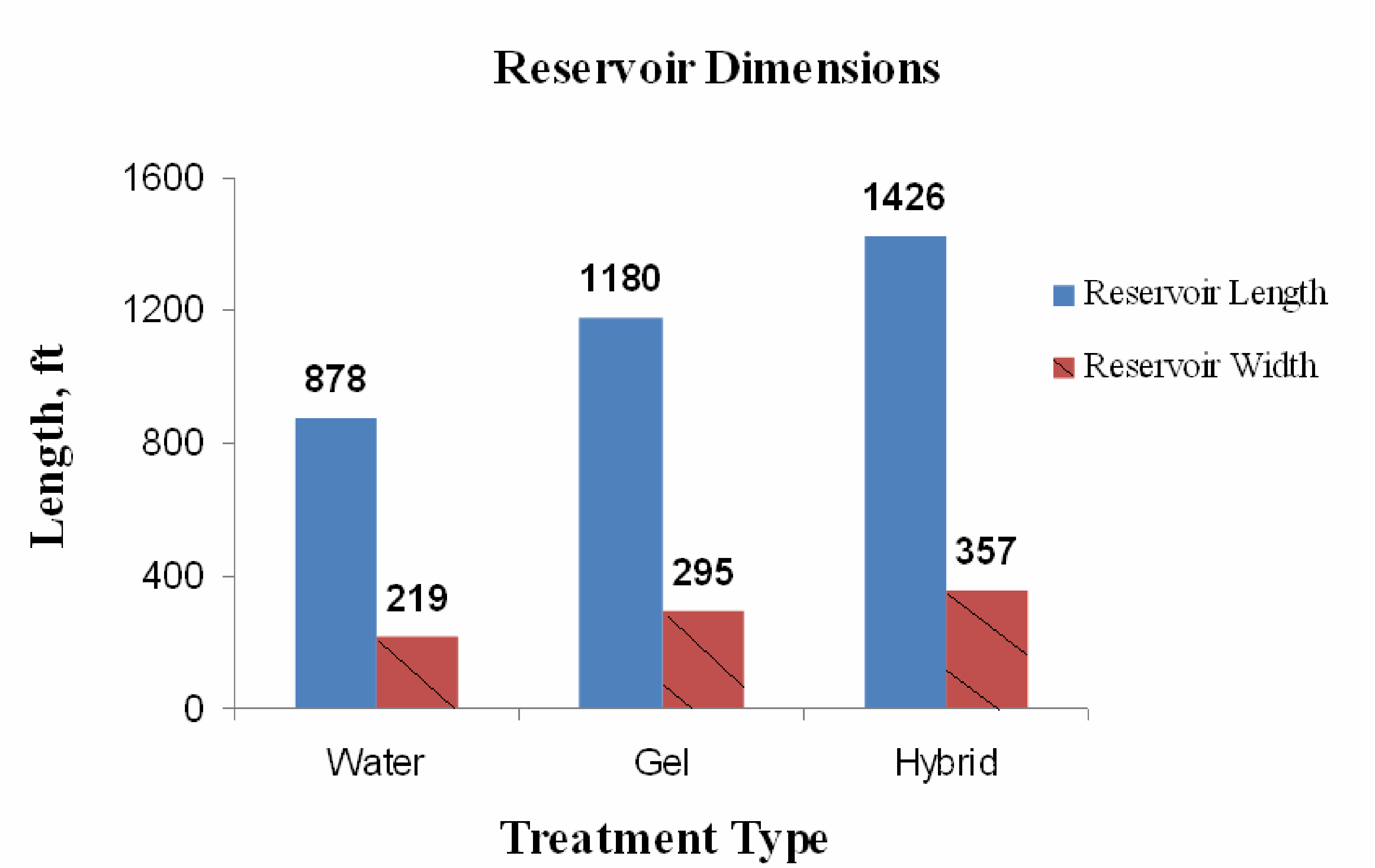


Fig. 4.8—Comparison of Average Estimated Rectangular Reservoir Dimensions Based on Treatment Type. (Elm Grove field)

Hypothesis Testing

We computed hypothesis tests on various data sets to strengthen our conclusions. The datasets are qualified using the Empirical rule and hence they are normally distributed.

Hypothesis:

Null hypothesis: H_0: $\mu_1 = \mu_2$ Means are equal for both data sets.

Research hypothesis: H_1: $\mu_1 \neq \mu_2$ Means are unequal for both data sets.

We compared the 10 year estimated values of cumulative gas production for the 3 treatments. Data for the hypothesis testing for all the wells are shown in **Table 4.8**. The p-value as shown in **Table 4.9** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the mean 10 year cumulative production was unequal for wells stimulated with Hybrid, Gel and Water fracture treatments with a 95% significance level. We could not compare water and gel fracture treatments because of high p value. So we can say that there is not enough evidence to prove that mean gas production for the water and gel fracture treatments are unequal. We also performed similar hypothesis testing based upon 5 year estimated values of cumulative gas production and OGIP (refer to Test B1 and B2 in Appendix B). **Figure 4.9** is a plot of the cumulative distribution function for 10 year estimated values of cumulative gas production for the 3 treatment types. Hybrid fracture treated wells are on the right side of Gel fracture treated wells. Also the Gel fracture treated wells are on the right side of water fracture treated wells. This indicates that the Hybrid fracture treated wells have better 10 year cumulative production than the Gel fracture treated wells and Gel fracture treated wells have better production than the Water fracture treated wells. We graphed similar CDF plots for 5 year cumulative gas production and Original Gas in Place (Test B1 and B2 in Appendix B). We also plotted CDF plots of OGIP and EUR in **Fig. 4.10**. The OGIP curve is on the right side of EUR, which suggests the assumption; EUR is 70% of OGIP is true. We conducted more hypothesis tests based on sand content, drainage area (Appendix B, Test B3 & B4) respectively**.** We obtain similar trends in all of them. But when we analyzed fracture half-length (Appendix B, Test B5) we found out that half-lengths of hybrid and gel fracture treatments are comparable to each other and both of them are way bigger than water fracture treatments.

Table 4.8—Data for Hypothesis Testing Based upon 10 Year Cumulative Gas Production.

10 Years Cumulative Gas Production	**Fracture Treatment**		
	Hybrid	**Gel**	**Water**
Mean, MMscf	487	344	247
Standard Deviation	214	73	121
Data Points	14	6	5

Table 4.9—Results of Hypothesis Testing Based upon 10 Year Cumulative Gas Production.

Parameter	**Values**		
	Hybrid Vs Gel	**Hybrid Vs Water**	**Gel Vs Water**
Rejection Criterion, α	0.05	0.05	0.05
Significance Level, p-value	0.04	0.01	0.17

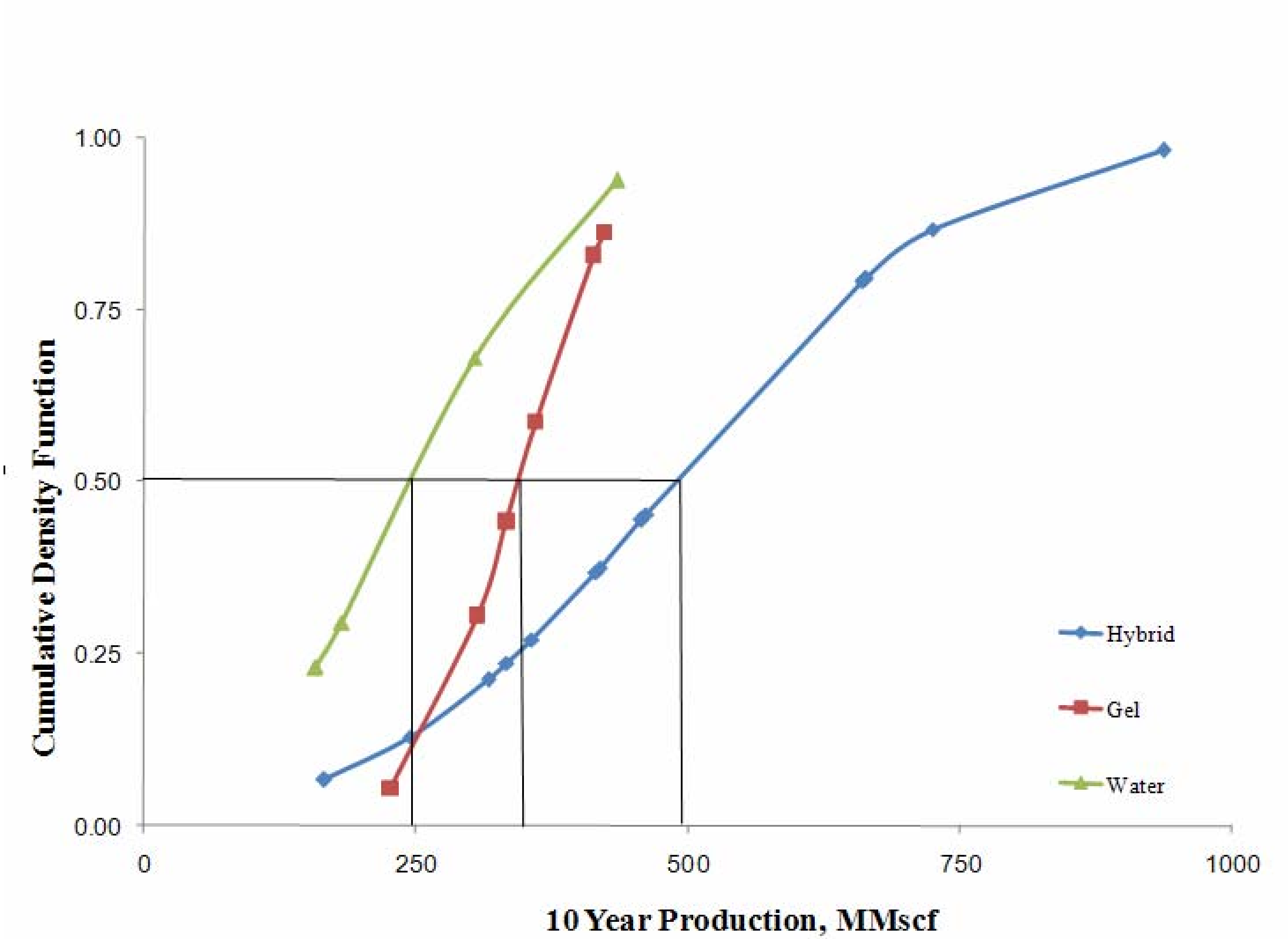


Figure 4.9— CDF for 10 Years Cumulative Gas Production Based on Treatment Type. (Elm Grove field)

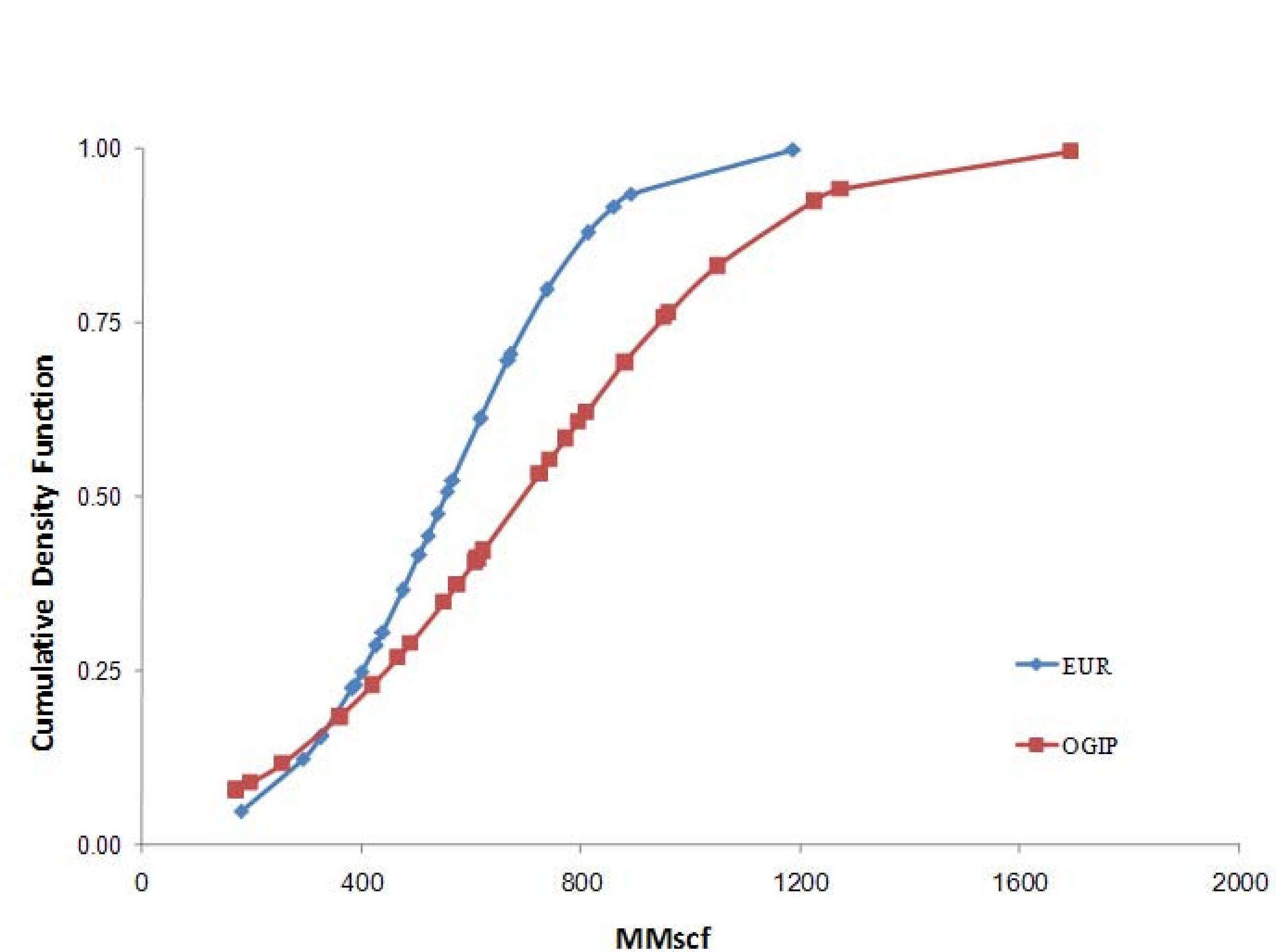


Figure 4.10—CDF for EUR and OGIP. (Elm Grove field)

4.2.2 Analysis by Region

We partitioned the Matador Resources acreage into 3 regions. **Table 4.10, 4.11,** and **4.12** show the output values from Promat for the northern, central and western regions. A summary of these regions is given in **Table 4.13.**

Table 4.10— Northern Region Wells Data Output. (Promat)

S.No	Permeability-thickness, mD-ft	Fracture Half-Length , ft	Drainage Area, acre	Sand Content, lb/gal	Reservoir Length, ft	Reservoir Width, ft
1	0.047	286	6.2	1.03	1039	260
2	0.095	342	8.9	1.55	1245	311
3	0.132	370	10.4	1.82	1346	337
4	0.079	326	8.1	1.15	1188	297
5	0.236	265	5.3	1.14	964	241
6	0.143	230	11.7	0.92	1428	357
7	0.306	308	7.2	1.54	1120	280
8	0.216	144	2.3	0.60	626	157
9	0.073	328	8.2	1.19	1195	299

Table 4.11— Central Region Wells Data Output. (Promat)

S.No	Permeability-thickness, mD-ft	Fracture Half-Length , ft	Drainage Area, acre	Sand Content, lb/gal	Reservoir Length, ft	Reservoir Width, ft
1	0.076	344	9.0	1.69	1252	313
2	0.090	230	7.2	0.88	1120	280
3	0.293	120	2.2	0.68	619	155
4	0.104	375	10.8	1.83	1372	343
5	0.050	208	3.3	1.01	758	190
6	0.066	230	5.5	0.99	974	244
7	0.088	366	10.2	1.59	1333	333
8	0.093	400	13.7	1.88	1545	386
9	0.271	183	2.5	0.67	665	166

Table 4.12—Western Region Wells Data Output. (Promat)

S.No	Permeability-thickness, mD-ft	Fracture Half-Length , ft	Drainage Area, acre	Sand Content, lb/gal	Reservoir Length, ft	Reservoir Width, ft
1	0.081	315	10.3	1.40	1340	335
2	0.205	180	10.6	0.67	1359	340
3	0.555	348	20.8	1.45	1904	476
4	0.387	271	13.9	1.27	1556	389
5	0.464	160	18.9	1.43	1815	454
6	0.495	249	22.8	1.55	1993	498
7	0.200	340	16.2	1.59	1680	420

Table 4.13— Summary of the Wells by Region.

Region	Permeability-thickness, mD-ft	Fracture Half-Length , ft	Drainage Area, acre	Sand Content, lb/gal	Reservoir Length, ft	Reservoir Width, ft
Northern	0.147	289	7.6	1.2	1128	282
Central	0.126	273	7.2	1.2	1071	268
Western	0.341	266	16.2	1.3	1664	416

Fig. 4.11 is a plot of the fracture half-lengths for different regions which indicate that all the regions have comparable half-lengths. **Figure 4.12** and **4.13** indicates that drainage area and the reservoir dimensions of the western part of the field are better than central and northern parts of the field.

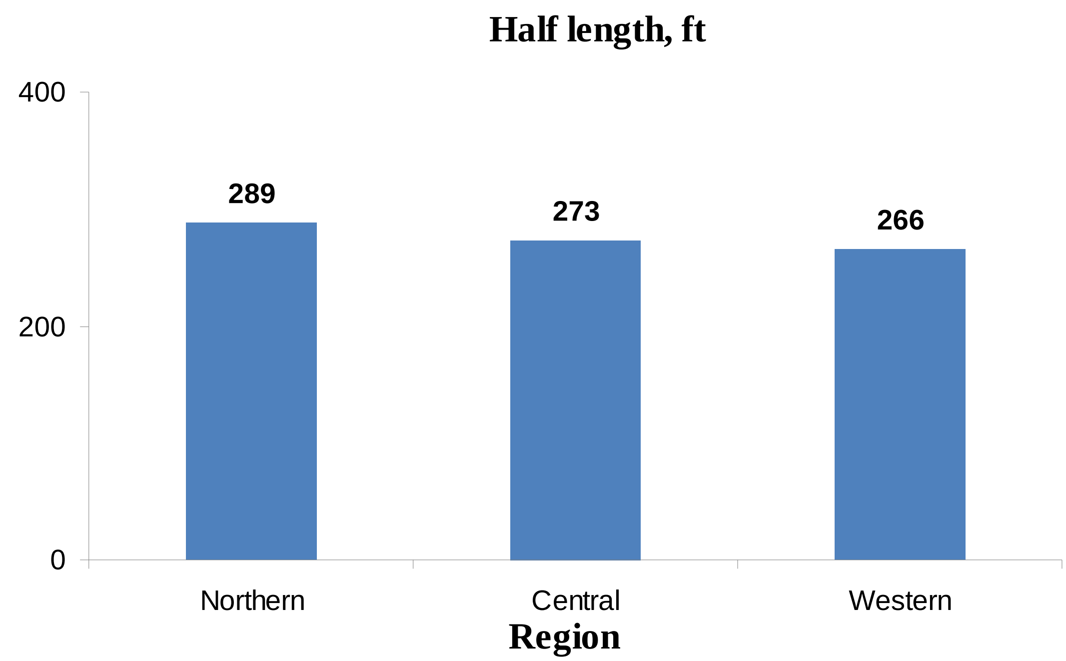


Fig. 4.11—Comparison of the Average Fracture Half-Length for Different Regions.

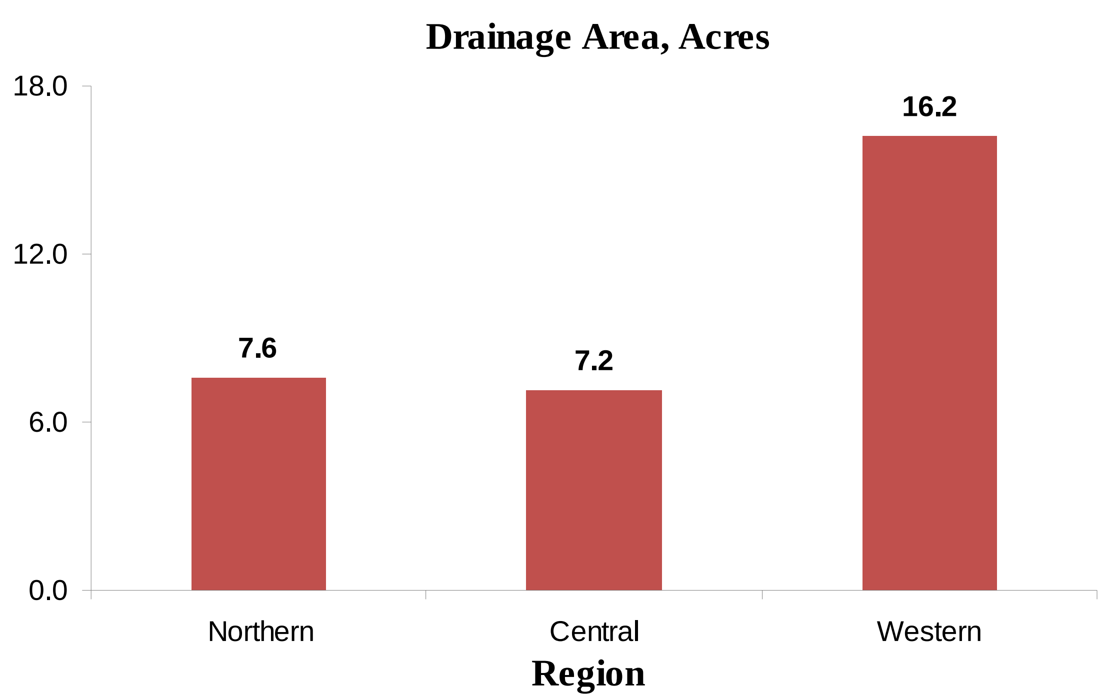


Figure 4.12—Comparison of the Average Drainage Area for Different Regions.

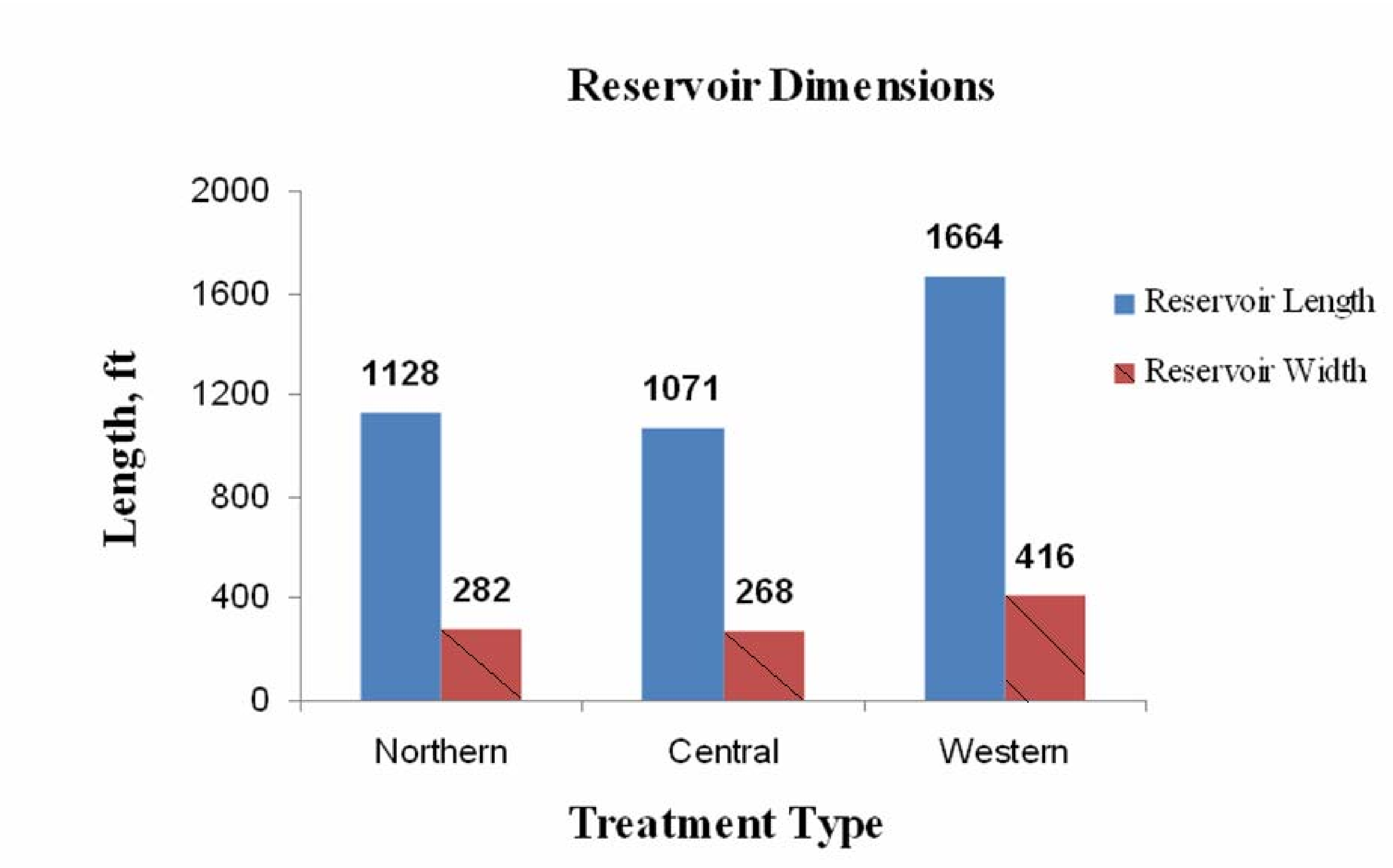


Figure 4.13— Comparison of the Average Rectangular Reservoir Dimensions for Different Regions of the Elm Grove Field.

Hypothesis Testing

Comparison of means of kh

We compared the kh for the 3 regions. Data for the hypothesis testing for all the wells are shown in **Table 4.14**. The p-value as shown in **Table 4.15** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the mean kh product was unequal for Western, Northern and Central regions with 95% significance level. But there is not enough evidence to prove that northern and central parts of the reservoir have unequal kh. Western wells do much better than the other two regions as shown in **Fig 4.14** when compared on the basis of permeability. **Figure 4.15** is a plot of CDF for permeability-thickness (kh) product for the 3 regions. We observe that the Western region wells have far better kh than the Northern region wells.

Table 4.14—Data for Hypothesis Testing Based upon kh.

kh	**Region**		
	North	**Central**	**West**
Mean, mD-ft	0.157	0.120	0.341
Standard Deviation	0.088	0.087	0.179
Data Points	8	10	7

Table 4.15—Results of Hypothesis Testing Based upon kh.

Parameter	**Values**		
	West Vs North	**West Vs Central**	**North Vs Central**
Rejection Criterion, α	0.05	0.05	0.05
Significance Level, p-value	0.06	0.02	0.35

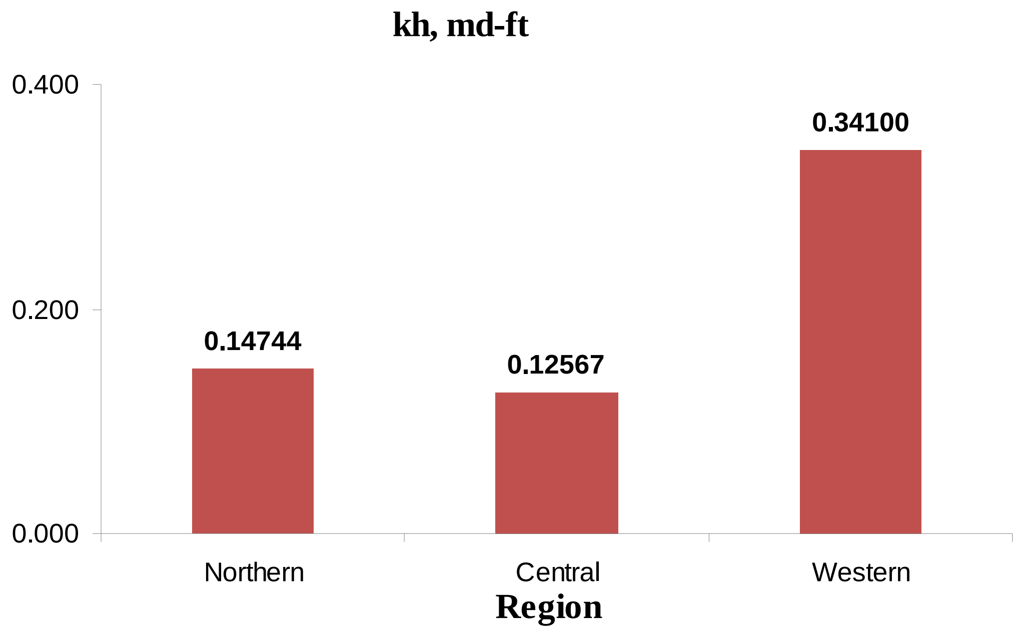


Figure 4.14— Comparison of Average Estimated kh for Various Regions. (Elm Grove)

We did similar hypothesis tests on the various data sets to strengthen our conclusions. All the data sets are qualified using the Empirical rule and hence they are normally distributed.We compared the 5 year estimated values of cumulative gas production (refer to Appendix C, Test C1), 10 year estimated values cumulative gas production (refer to Appendix C, Test C2), OGIP (refer to Appendix C, Test C3), and drainage area (refer to Appendix C, Test C4).

We computed the fracture half length versus estimated 5 year cumulative gas production for various kh values. **Fig. 4.16, Fig. 4.17** & **Fig. 4.18** are plots for a drainage area of 10 acres, 20 acres and 40 acres respectively.

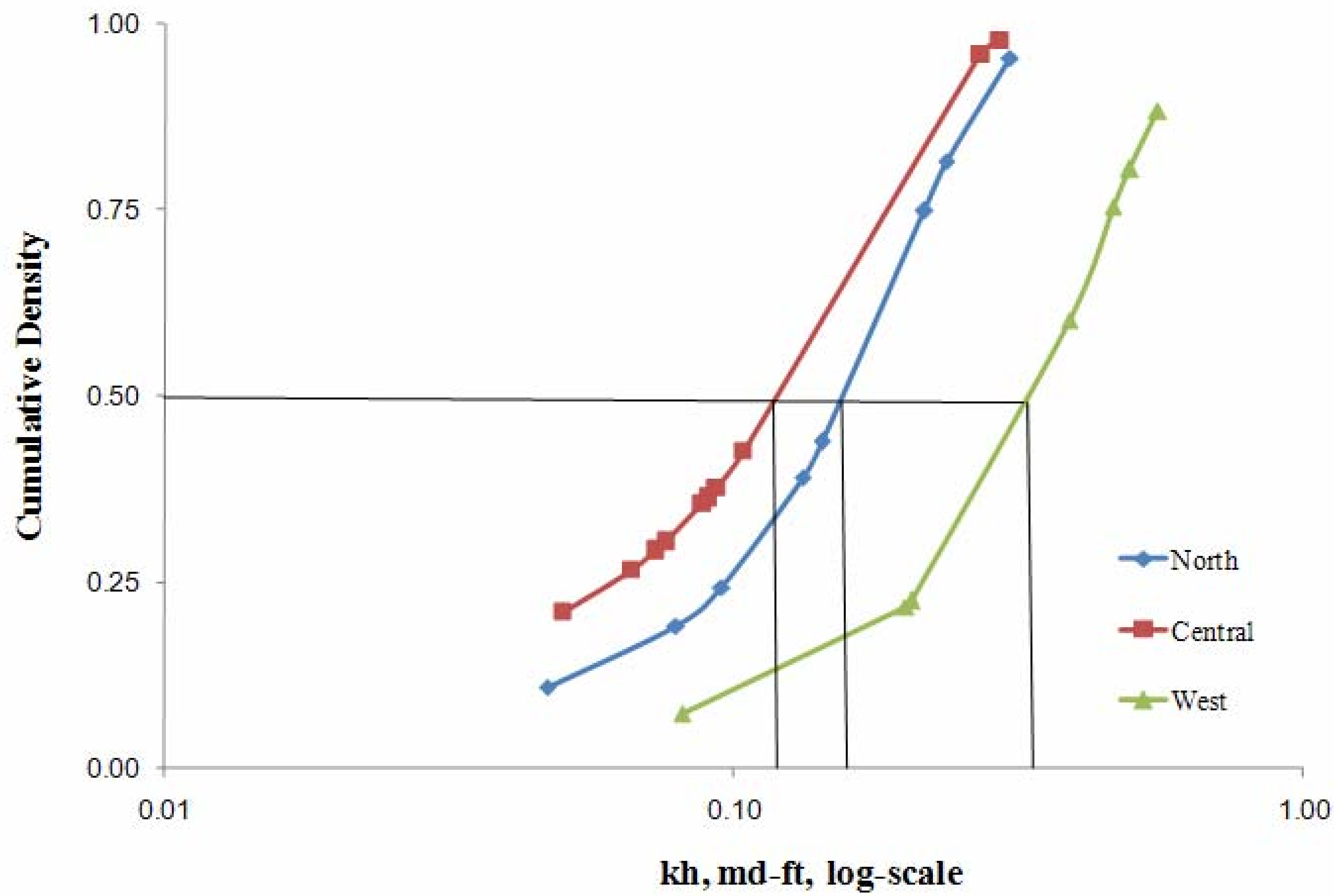


Figure 4.15—CDF for kh Based on Different Regions. (Elm Grove field)

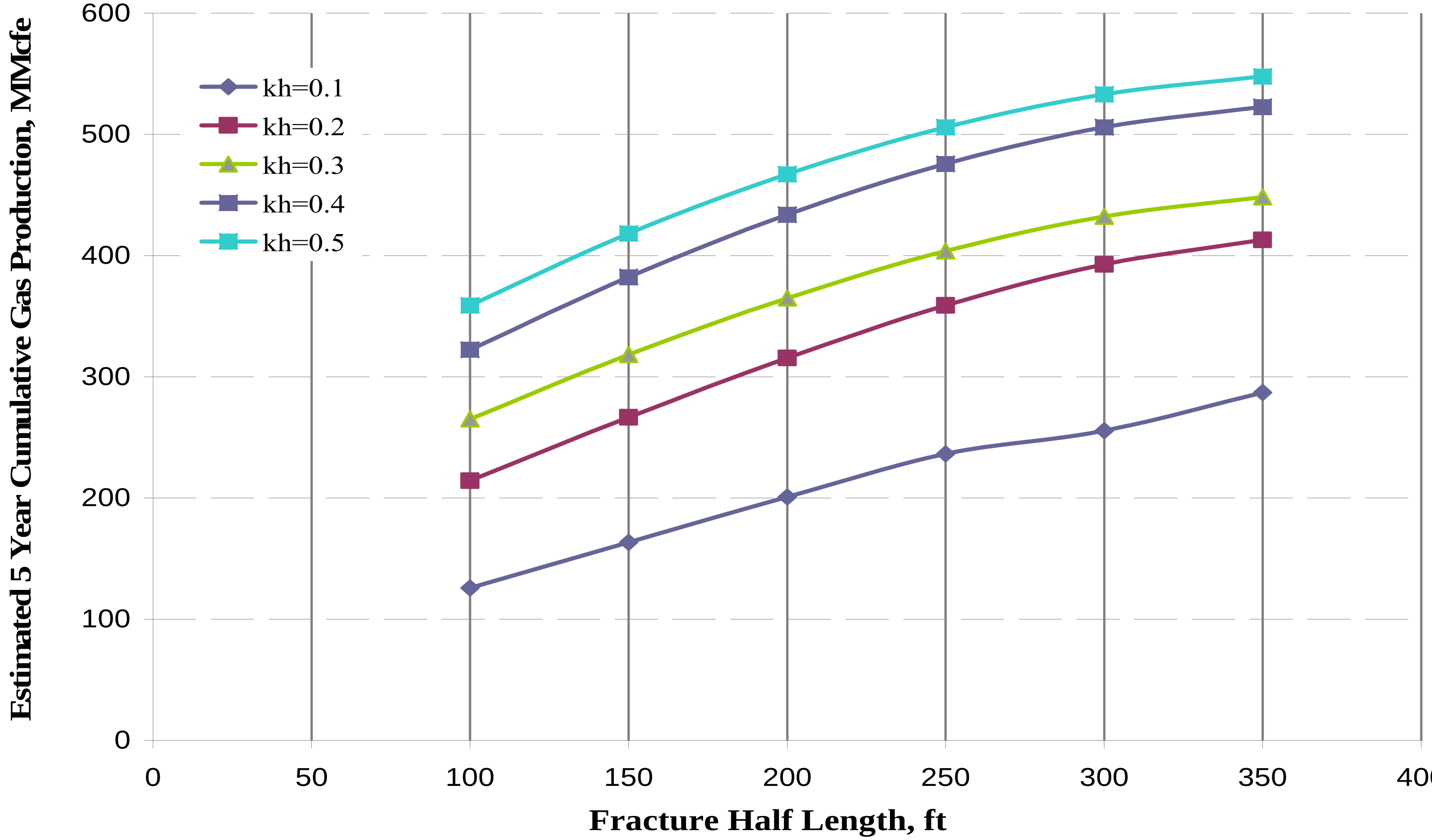


Figure 4.16—Fracture Half Lengths for Various kh Values for a Drainage Area of 10 Acres. (Elm Grove field)

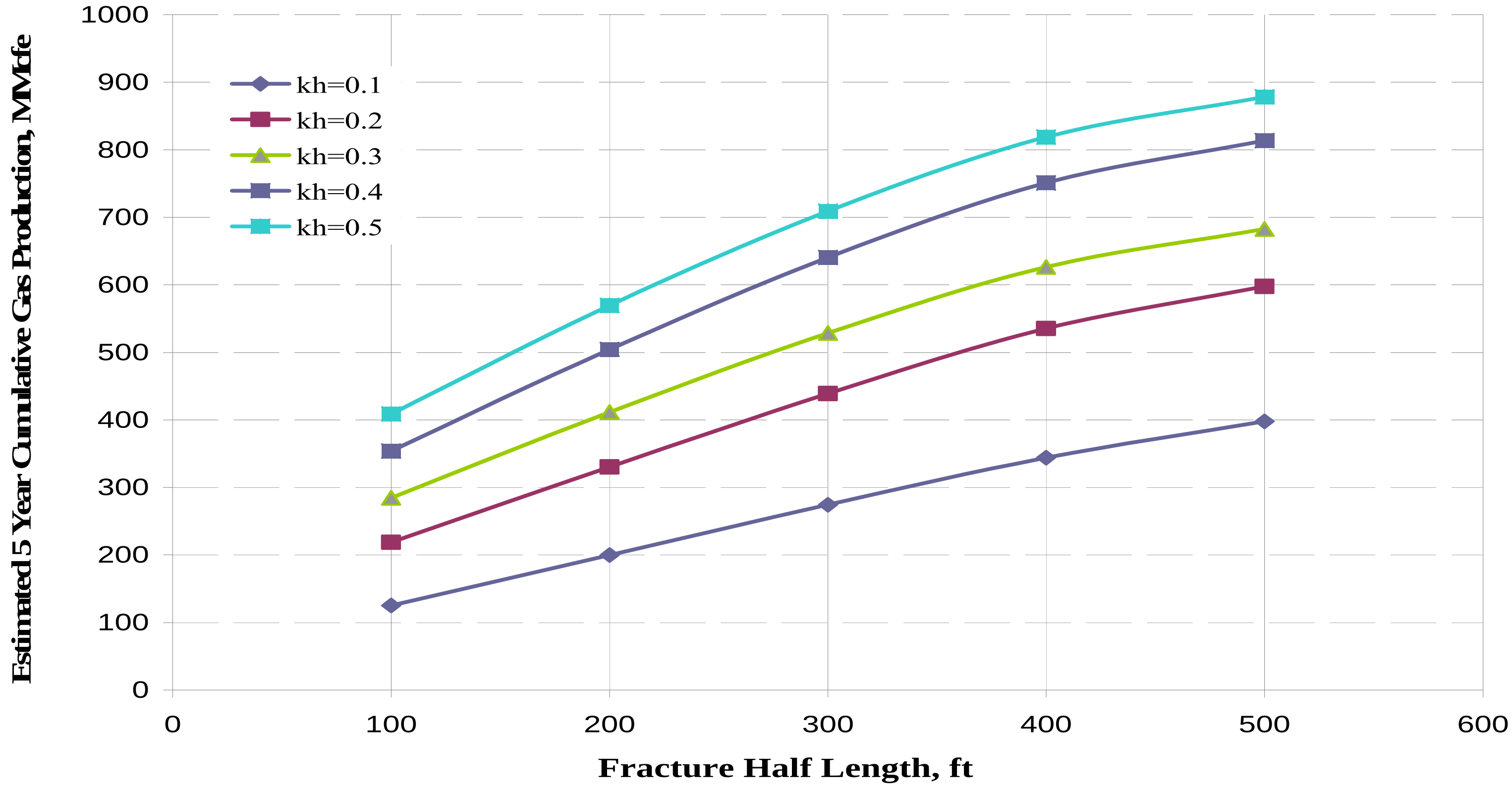


Figure 4.17—Fracture Half Lengths for Various kh Values for a Drainage Area of 20 Acres. (Elm Grove field)

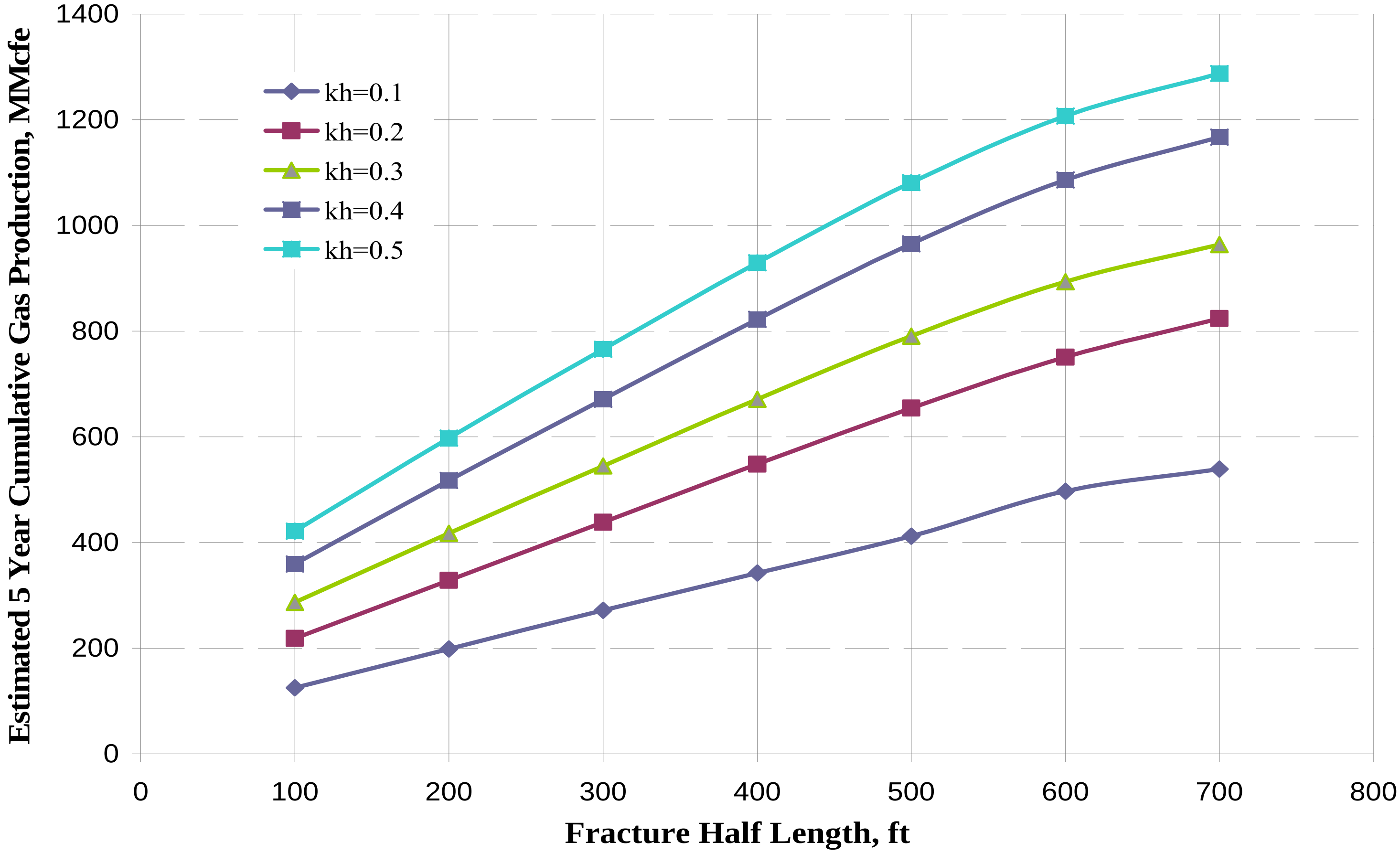


Figure 4.18—Fracture Half Lengths for Various kh Values for a Drainage Area of 40 Acres. (Elm Grove field)

4.3 Economic Analysis of Elm Grove Field

Tables 4.16 to **4.19** are matrix views of the values of Rate of Return (ROR) for various gas prices and 5 year cumulative gas production at a fixed drilling and completion costs.

Fig. 4.19 is a graph of ROR for various 5 year cumulative gas production curves for drilling and completion cost of $1.4 Million. We observe that at $9 /MMBtu ROR for 700 MMcfe curve is the highest and 550 MMcfe curve is the lowest. This indicates the ROR of the wells is directly dependent on the gas prices. We conclude that as the 5 year cumulative gas production increases, the ROR will increase. Also, for a given drilling and completion cost, there are numerous combinations of gas price and gas production that will provide acceptable values of ROR.

Similarly **Fig. 4.20** is a plot of ROR for various 5 year cumulative gas production curves for drilling and completion cost of $1.6 Million. To get a 40% ROR on a well with 700 MMcfe the gas price needs to be $6.6 /MMBtu. For a 400 MMcfe well the price needs to be $9 /MMBtu for the well to be economical. Also we can conclude that higher the 5 year cumulative gas production lower is the gas price for the well to be economic. With the help of 5 year cumulative gas production estimates we can estimate the gas price for a particular ROR.

Table 4.16—Rate of Return for Drilling & Completion Cost of $1.4 Million.

Drilling & Completion Cost =$1.4 Million LOE = Base Case Less 25%					
Gas Price $/MMBtu	**5 Years cumulative MMcfe**				
	100	250	400	550	700
6.0	NPO	NPO	NPO	20.2	42.1
7.0	NPO	NPO	9.3	36.9	63.7
8.0	NPO	NPO	20.5	54.4	87.2
9.0	NPO	NPO	31.7	73.1	112.9
10.0	NPO	4.3	43.2	93.3	140.9
12.0	NPO	18.5	67.3	138.5	204.3

Table 4.17—Rate of Return for Drilling & Completion Cost of $1.5 Million.

Drilling & Completion Cost =$1.5 Million LOE = Base Case Less 25%					
Gas Price $/MMBtu	**5 Years cumulative MMcfe**				
	100	250	400	550	700
6.0	NPO	NPO	NPO	14.8	35.1
7.0	NPO	NPO	4.8	30.1	54.8
8.0	NPO	NPO	15.3	46.0	75.9
9.0	NPO	NPO	25.7	62.9	98.8
10.0	NPO	NPO	36.3	80.9	123.7
12.0	NPO	13.9	58.2	121.0	179.8

ROR	<10%	10%-25%	>25%

NPO = Negative Pay Out

Table 4.18—Rate of Return for Drilling & Completion Cost of $1.6 Million.

Drilling & Completion Cost =$1.6 Million LOE = Base Case Less 25%					
Gas Price $/MMBtu	**5 Years cumulative MMcfe**				
	100	250	400	550	700
6.0	NPO	NPO	NPO	10.0	29.1
7.0	NPO	NPO	NPO	24.3	47.2
8.0	NPO	NPO	10.7	38.9	66.4
9.0	NPO	NPO	20.5	54.3	87.0
10.0	NPO	NPO	30.3	70.6	109.3
12.0	NPO	9.2	50.5	106.5	159.4

Table 4.19—Rate of Return for Drilling & Completion Cost of $1.7 Million.

Drilling & Completion Cost =$1.7 Million LOE = Base Case Less 25%					
Gas Price $/MMBtu	**5 Years cumulative MMcfe**				
	100	250	400	550	700
6.0	NPO	NPO	NPO	5.8	23.9
7.0	NPO	NPO	NPO	19.2	40.7
8.0	NPO	NPO	6.7	32.8	58.2
9.0	NPO	NPO	15.9	46.9	77.0
10.0	NPO	NPO	25.1	61.8	97.2
12.0	NPO	5.0	43.9	94.3	142.2

ROR	<10%	10%-25%	>25%

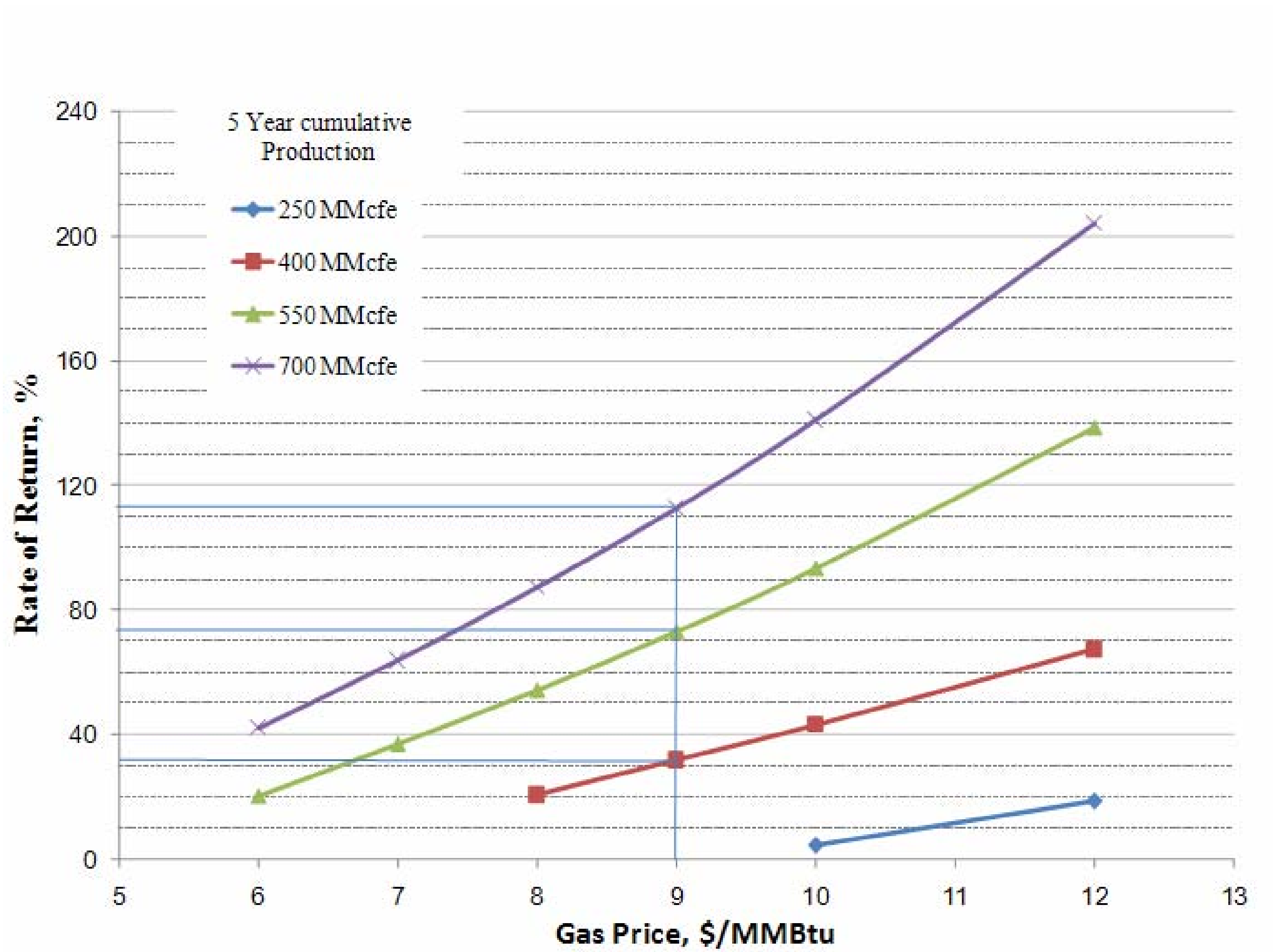


Figure 4.19—ROR of Various 5 Year Cumulative Gas Production for Drilling and Completion Cost of $1.4 Million.

(Elm Grove Field).

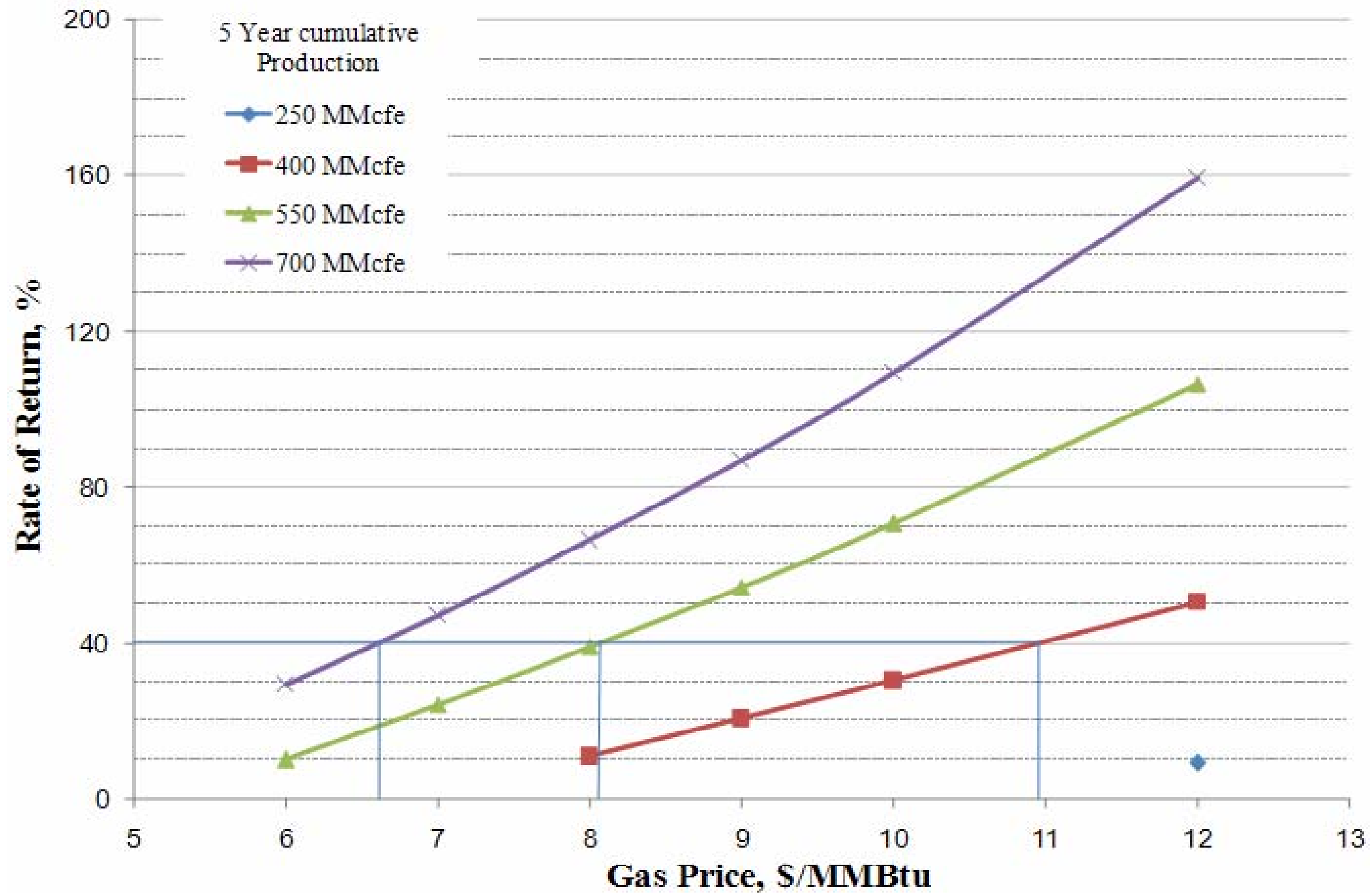


Figure 4.20—ROR of Various 5Year Cumulative Gas Production for Drilling and Completion Cost of $1.6 Million.

(Elm Grove Field)

Tables 4.20 to **4.25** are matrix views of ROR for various drilling and completion costs and 5 year cumulative gas production at a fixed gas price. **Fig. 4.21** is a plot of ROR for various 5 year cumulative gas production curves for gas price of 12$/MMBtu. We observe that at $1.6 Million drilling and completion cost 700 MMcfe curve has the best ROR and the 250 MMcfe curve has the least. Similarly in **Fig. 4.22** is a plot of ROR for various 5 year cumulative gas production curves for gas price of $8 /MMBtu. These plots indicate that the ROR of the wells is directly dependent on the drilling and completion costs. **Fig. 4.23** is a plot of ROR for various D&C costs for a gas price of $12 /MMBtu.

From the ROR **Tables 4.16** to **4.19** we can say that a 5 year cumulative gas production above 325 MMcfe at gas price of $9 /MMBtu gives a ROR of 10% or greater. **Figure 4.24** is a plot of 30 days and 180 days production versus the 5 year cumulative gas production fitted by a polynomial curve. From this figure we observe that the 180 days production of a well must be at least 90 MMcfe and the 30 day production must be more than 35 MMcfe for the wells to be producing more than 325 MMcfe.

Of the 25 wells in the Elm Grove field, only 9 wells had 180 days production of more than 90 MMcfe as shown in **Table 4.26**. Seven of those were Hybrid fracture treated wells, two were Gel fracture treated wells and none of them are water fracture wells. We conclude that hybrid fracture treated wells are better than gel or water fracture wells. Similarly from **Fig. 4.25** the wells need to have an average drainage area of more than 11.1 acres to have a 5 year cumulative gas production of more than 325 MMcfe.

Table 4.20—Rate of Return for Gas Price of $6 /MMBtu.

Gas Price $6 /MMBtu LOE = Base Case Less 25%					
D/C costs MM$	5 Years cumulative MMcfe				
	100.0	250.0	400.0	550.0	700.0
1.4	NPO	NPO	NPO	20.2	42.1
1.5	NPO	NPO	NPO	14.8	35.1
1.6	NPO	NPO	NPO	10.0	29.1
1.7	NPO	NPO	NPO	5.8	23.9

Table 4.21—Rate of Return for Gas Price of $7 /MMBtu.

Gas Price $7 /MMBtu LOE = Base Case Less 25%					
D/C costs MM$	5 Years cumulative MMcfe				
	100.0	250.0	400.0	550.0	700.0
1.4	NPO	NPO	9.3	36.9	63.7
1.5	NPO	NPO	4.8	30.1	54.8
1.6	NPO	NPO	NPO	24.3	47.2
1.7	NPO	NPO	NPO	19.2	40.7

Table 4.22—Rate of Return for Gas Price of $8 /MMBtu.

Gas Price $8 /MMBtu LOE = Base Case Less 25%					
D/C costs MM$	5 Years cumulative MMcfe				
	100.0	250.0	400.0	550.0	700.0
1.4	NPO	NPO	20.5	54.4	87.2
1.5	NPO	NPO	15.3	46.0	75.9
1.6	NPO	NPO	10.7	38.9	66.4
1.7	NPO	NPO	6.7	32.8	58.2

ROR	<10%	10%-25%	>25%

Table 4.23—Rate of Return for Gas Price of $9 /MMBtu.

Gas Price $9 /MMBtu LOE = Base Case Less 25%					
D/C costs MM$	5 Years cumulative MMcfe				
	100.0	250.0	400.0	550.0	700.0
1.4	NPO	NPO	31.7	73.1	112.9
1.5	NPO	NPO	25.7	62.9	98.8
1.6	NPO	NPO	20.5	54.3	87.0
1.7	NPO	NPO	15.9	46.9	77.0

Table 4.24—Rate of Return for Gas Price of $10 /MMBtu.

Gas Price $10 /MMBtu LOE = Base Case Less 25%					
D/C costs MM$	5 Years cumulative MMcfe				
	100.0	250.0	400.0	550.0	700.0
1.4	NPO	4.3	43.2	93.3	140.9
1.5	NPO	NPO	36.3	80.9	123.7
1.6	NPO	NPO	30.3	70.6	109.3
1.7	NPO	NPO	25.1	61.8	97.2

Table 4.25—Rate of Return for Gas Price of $12 /MMBtu.

Gas Price $12 /MMBtu LOE = Base Case Less 25%					
D/C costs MM$	5 Years cumulative MMcfe				
	100.0	250.0	400.0	550.0	700.0
1.4	NPO	18.5	67.3	138.5	204.3
1.5	NPO	13.9	58.2	121.0	179.8
1.6	NPO	9.2	50.5	106.5	159.4
1.7	NPO	5.0	43.9	94.3	142.2

ROR	<10%	10%-25%	>25%

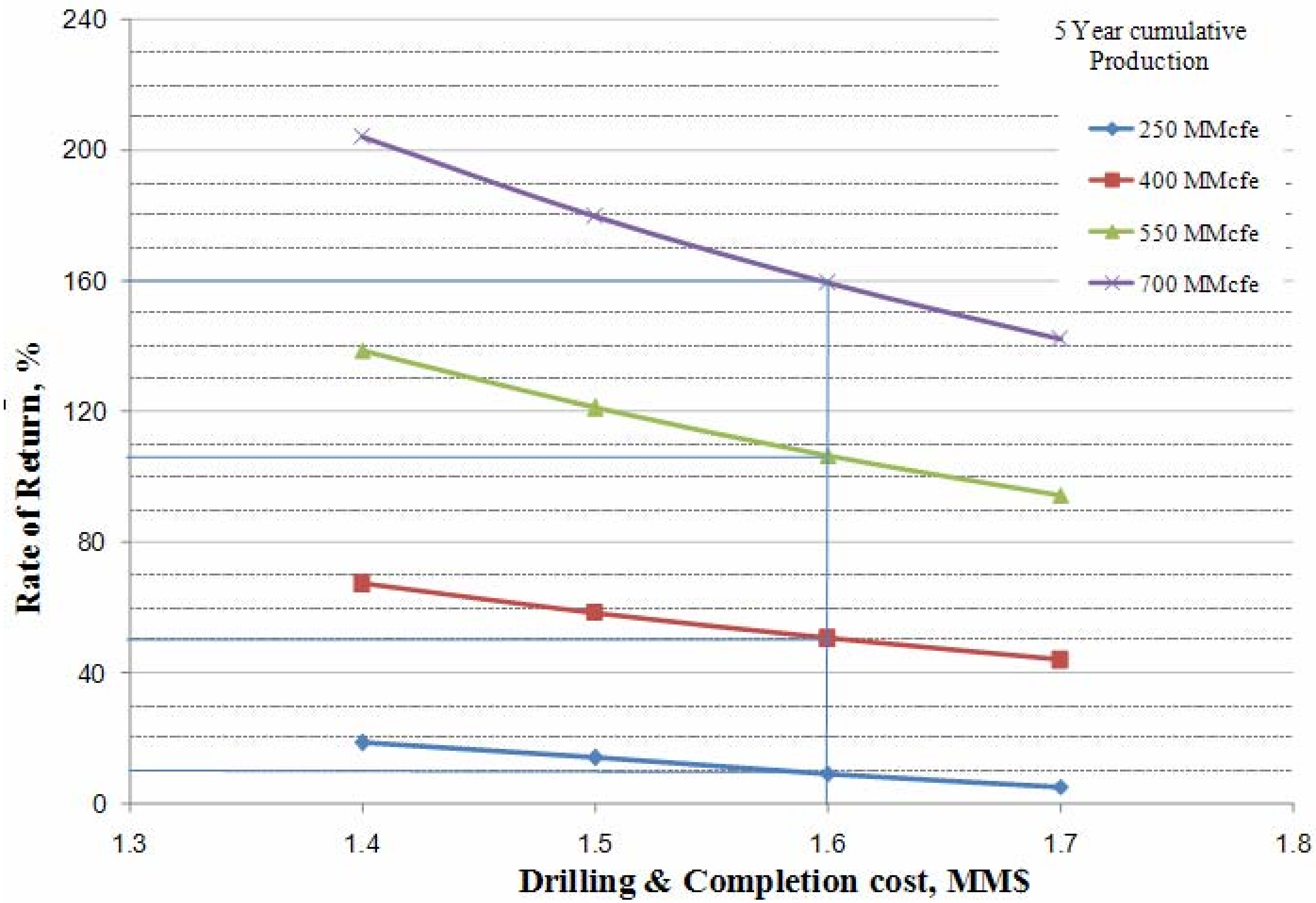


Figure 4.21—ROR of Various 5 Year Cumulative Gas Productions for Gas Price of $12 /MMBtu. (Elm Grove Field)

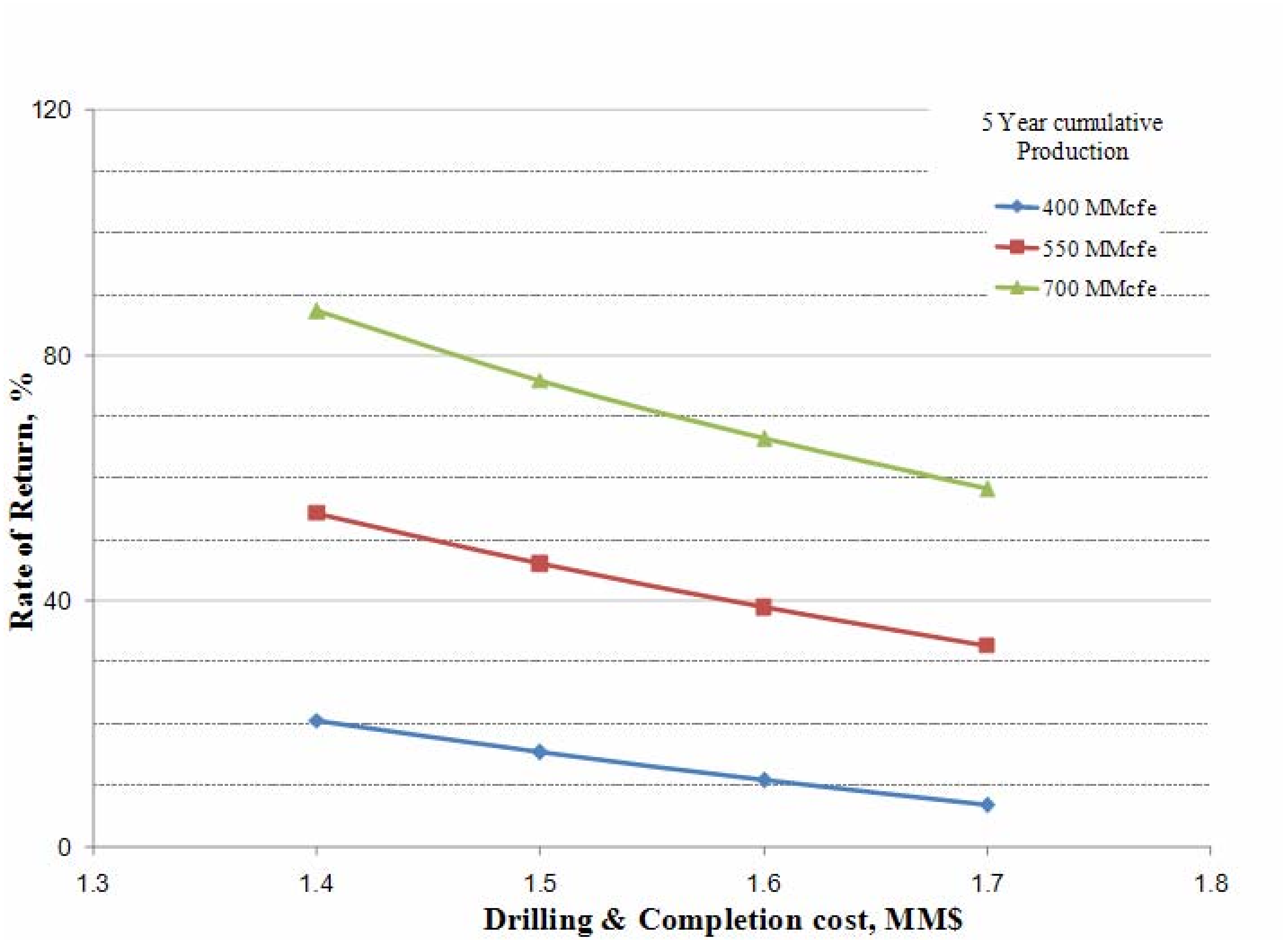


Figure 4.22—ROR of Various 5 Year Cumulative Gas Productions for Gas Price of $8 /MMBtu. (Elm Grove Field)

Table 4.26—180 Days Cumulative Gas Production for Wells in the Elm Grove Field with a 5 year Cumulative Gas Production Greater than 325 MMcfe.

Well Name	Treatment type	180 days Production MMcfe
Colbert et al. No. 1	Gel	90
Caspiana Int. No 1 Alt.	Gel	122
D.E.S. Land Co. 34 No. 1	Hybrid	121
EMW Land Co., LLC 29 No. 1	Hybrid	96
J.T. Harris, Inc. No. 1-Alt.	Hybrid	97
EMW Land Co., LLC 29 No. 2-Alt.	Hybrid	145
Blount Farms No. 1	Hybrid	90
EMW Land Co., LLC 29 No. 4-Alt.	Hybrid	154
EMW Land Co., LLC 29 No. 3-Alt.	Hybrid	123

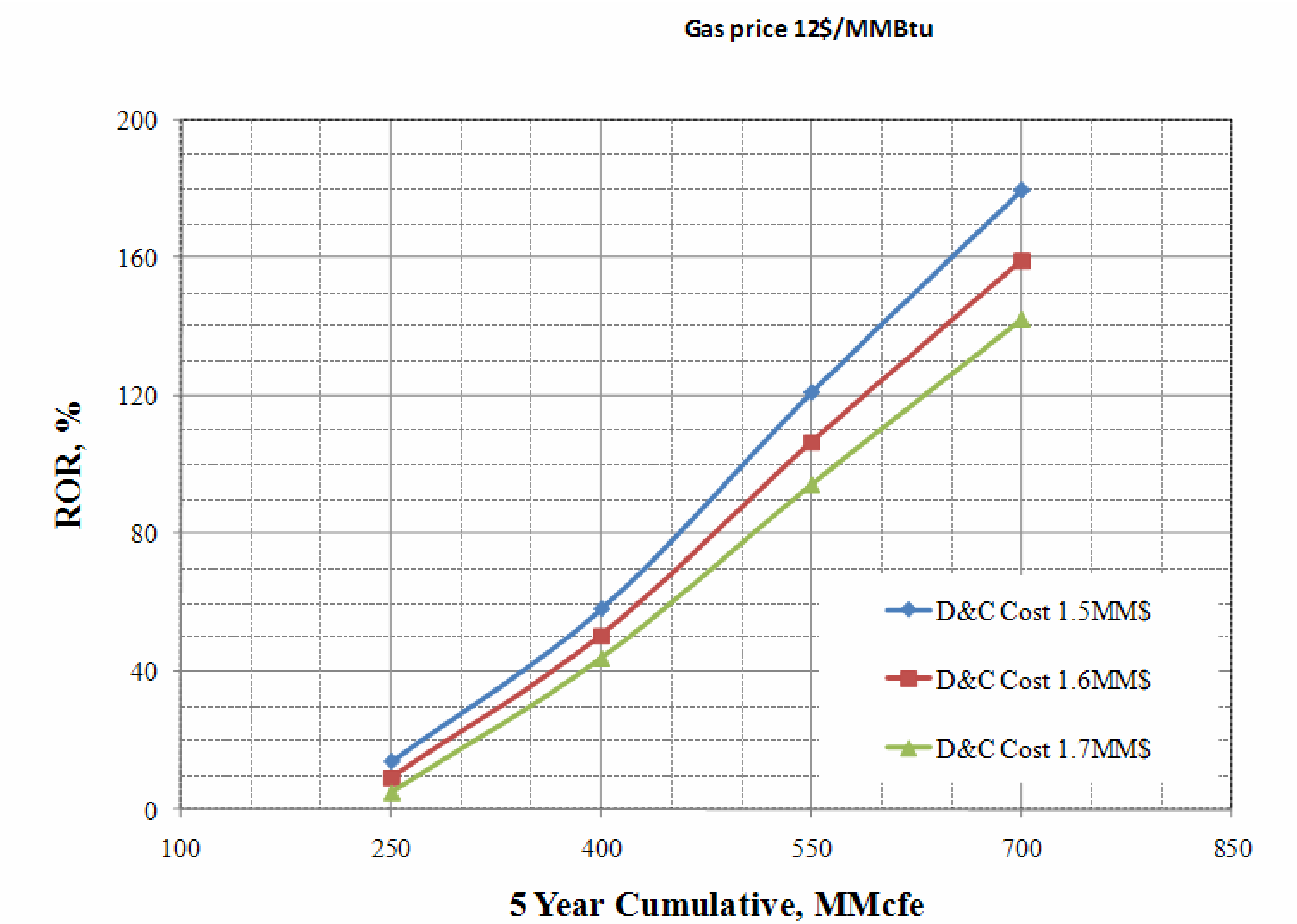


Fig 4.23—ROR for Different 5 Year Cumulative Production for Varying D&C Costs. (Elm Grove Wells)

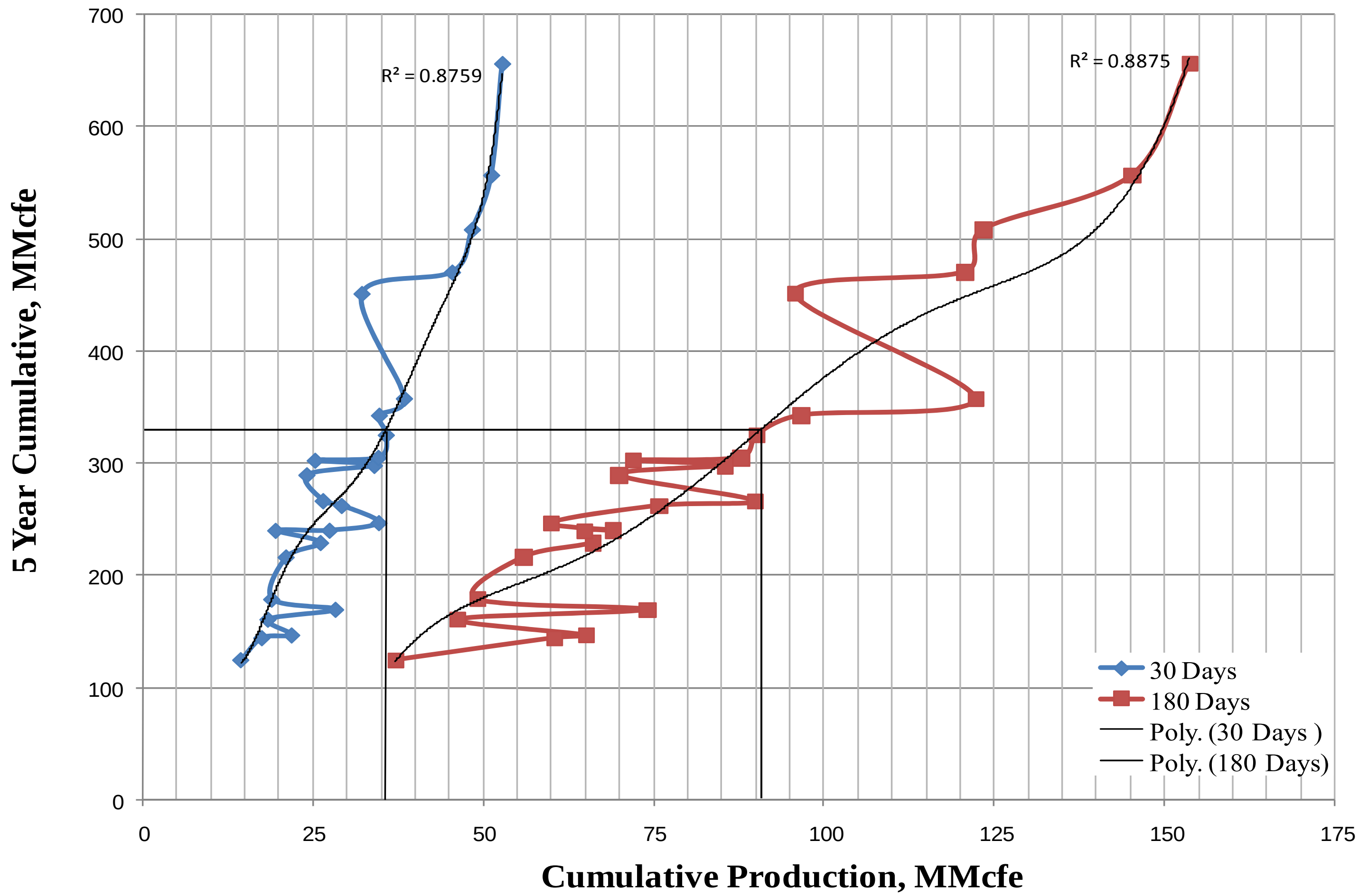


Fig 4.24—30 Days and 180 Days Production for Wells in the Elm Grove Field.

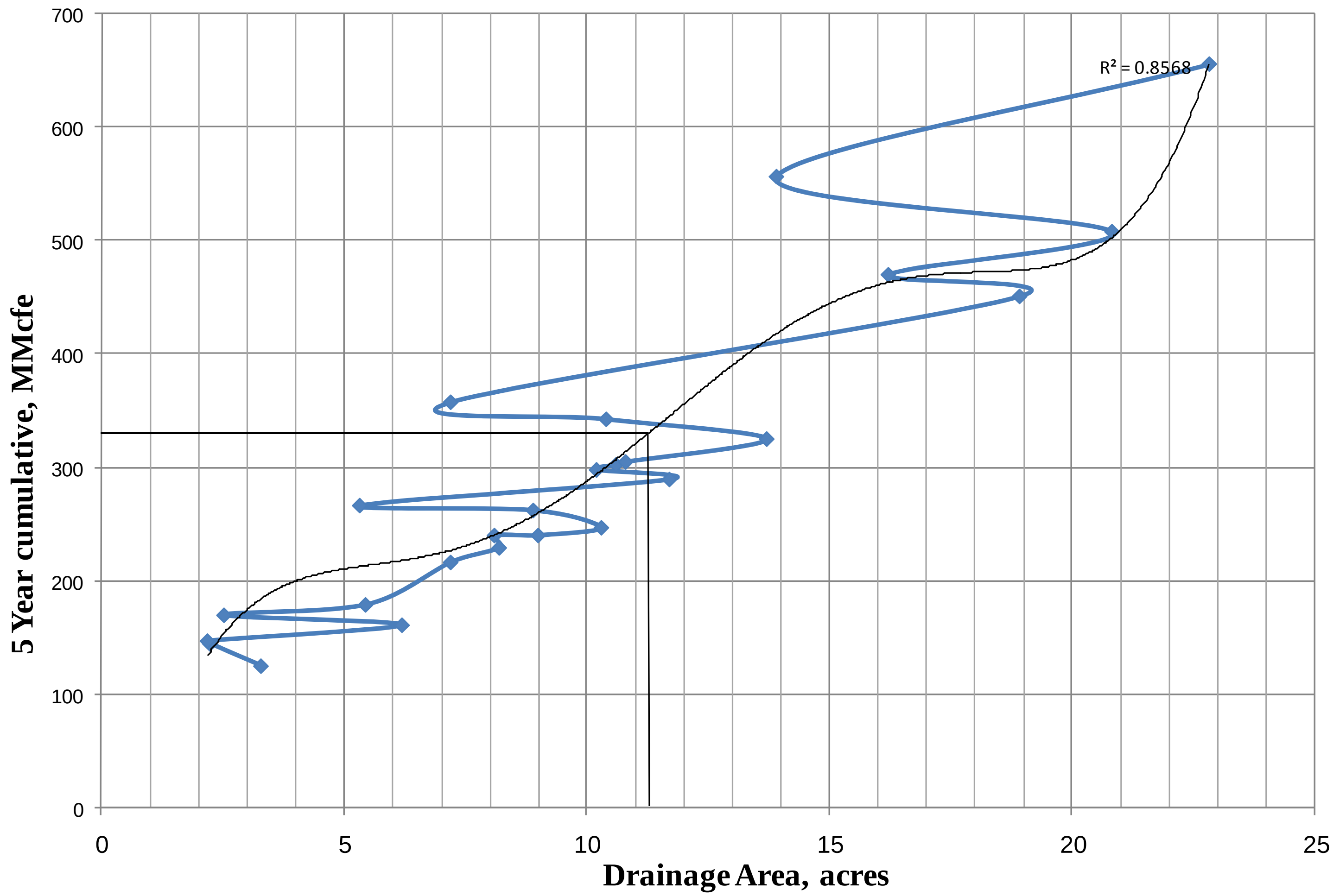


Fig 4.25—Drainage Area for the Wells in the Elm Grove Field.

4.4 Determination of Fracture Half Length in Elm Grove Field

Tables 4.16 to 4.19 give ROR for values of gas price, drilling costs for different values of estimated 5 year cumulative production. To determine the fracture half-length required to achieve a ROR >10% we need to know the kh and drainage area. We can then use Figs. 4.16 to 4.18 to determine the effective fracture half-length required to produce a minimum amount of gas to have a ROR >10%.

For example from Table 4.16 we can see that a Drilling and Completion cost of $1.4 Million at a gas price of $7 /MMBtu gives a ROR of 9.3% for an estimated 5 year cumulative production of 400 MMcfe. Then from Fig. 4.17 at a kh of 0.2 md-ft and estimated 5 year cumulative production of 400 MMcfe we would need an estimated fracture half-length of 265 ft.

Similarly from Table 4.18 we can see that a Drilling and Completion cost of $ 1.6 Million at a gas price of $8 /MMbtu gives a ROR of 10.7% for an estimated 5 year cumulative production of 400 MMcfe. Then form Fig. 4.16 at a kh of 0.3 md-ft and estimated 5 year cumulative production of 400 MMcfe we would need an estimated fracture half-length of 250 ft.

CHAPTER V

CONCLUSIONS

On the basis of our research we have the following conclusions:

- Evaluation of the field data from the wells in the Oak Hill field completed in the Cotton Valley sands suggest that high sand content wells produce more gas than the low sand content wells based on Best 6 months and Best 3 months gas production with 95% statistical confidence. The data also suggest that wells with high initial pressure produce more gas than low initial pressure wells. All the results were comparable to the Carthage field wells completed in the Cotton Valley sands done by Malpani (2006).
- Comparison of various fracture treatment types by history matching gas production from a sample of Cotton Valley wells in the Elm Grove field indicates that hybrid fractures have the largest drainage area, and longest fracture half-lengths. Gel fracture treatments have smaller drainage area but comparable fracture half-lengths. While water fracture treatments have the smallest drainage area and fracture half-length.

- Comparison of various regions of the Elm Grove field from the same sample of Cotton Valley wells operated by Matador Resources by history matching using an analytical reservoir simulator indicates that the western region of the field has much better kh values than the northern and central parts of the field with a 95% confidence interval. Also the western part has better drainage area and better gas production than other regions of the field based on 5 year and 10 year estimated values of cumulative gas production.
- Economic analysis of the wells in the Elm Grove field operated by Matador Resources suggest that a well must produce a minimum of 90 MMcfe in 3 months to get a ROR of greater than 10% at a gas price of $9 /MMBtu. This analysis also suggests that only hybrid and gel fracture treatments can give high ROR.

NOMENCLATURE

BHP = Bottom Hole Pressure

MSC = Medium Sand Content

HSC = High Sand Content

PPG = Pounds per Gallon

ROR = Rate of Return

NPO = Negative Problem Orientation

LPC = Low Proppant Concentration

MPC = Medium Proppant Concentration

OGIP = Original Gas-in-place

EUR = Estimated Ultimate Recovery

Tcf = Trillion Cubic Feet

DOFP = Date of First Production

CDF = Cumulative Distribution Function

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APPENDIX A

Comparison of Means for Best 3 months gas production for Oak Hill field

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

Gas Production Best 3 months	Group I		Group II	
	HSC	MSC	HSC	MSC
Mean, Mcf/month	35,923	26,225	31,231	23,996
Standard Deviation	10,597	8,339	10,350	8,149
Data Points	25	22	19	23

The Empirical rule was used to test normality of datasets shown in the following table.

Gas Production Best 3 months	Group I		Group II	
	HSC	MSC	HSC	MSC
Mean ± 2 Std. Dev.	96	95	100	100
Mean ± 3 Std. Dev.	100	100	100	100

All datasets qualified using the Empirical rule, hence they are normally distributed.

Hypothesis:

Null hypothesis: H_0: $\mu_1 = \mu_2$ Means are equal for both data sets.

Research hypothesis: H_1: $\mu_1 \neq \mu_2$ Means are unequal for both data sets

Comparing HSC with MSC

Parameter	**Values**	
	Group I	**Group II**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.0011	0.0018

From the results shown we reject the null hypothesis with 95% confidence because p-value is less than rejection criterion, α. This implies that the mean gas production for HSC and MSC are unequal. Also, **Fig. A-1** indicates that HSC has better mean than MSC for both the groups.

Fig. A-2 is a plot of CDF for Best 3 months gas production for group I wells with different sand content.

Fig. A-3 is a plot of CDF for Best 3 months gas production for HSC wells with different pressure groups I and II.

Fig. A-4 is a plot of cumulative distribution function for Best 3 months gas production for both pressure groups and both sand content.

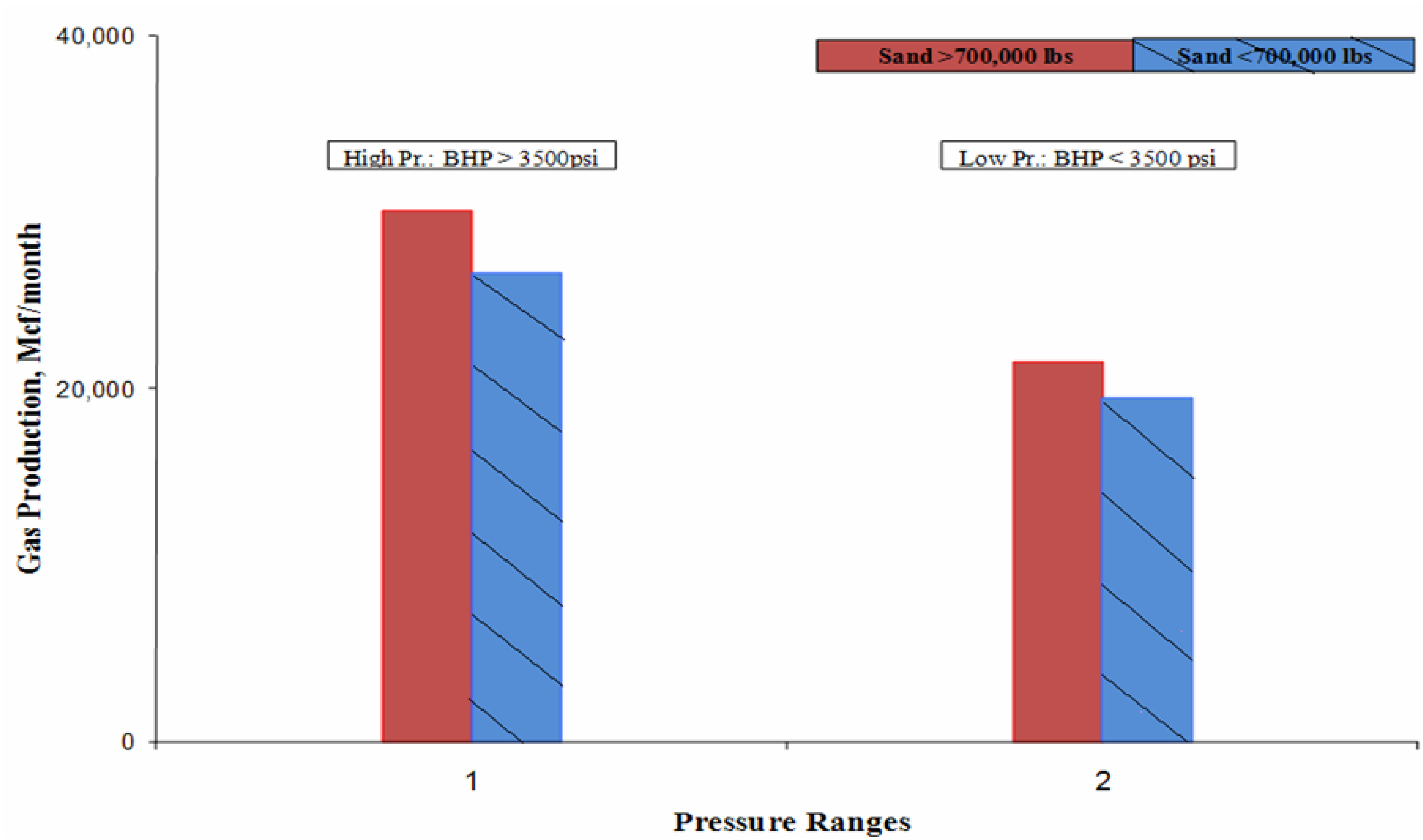

Figure A-1—Comparison of Average Best 3 Months Gas Production for Wells in the Oak Hill Field.

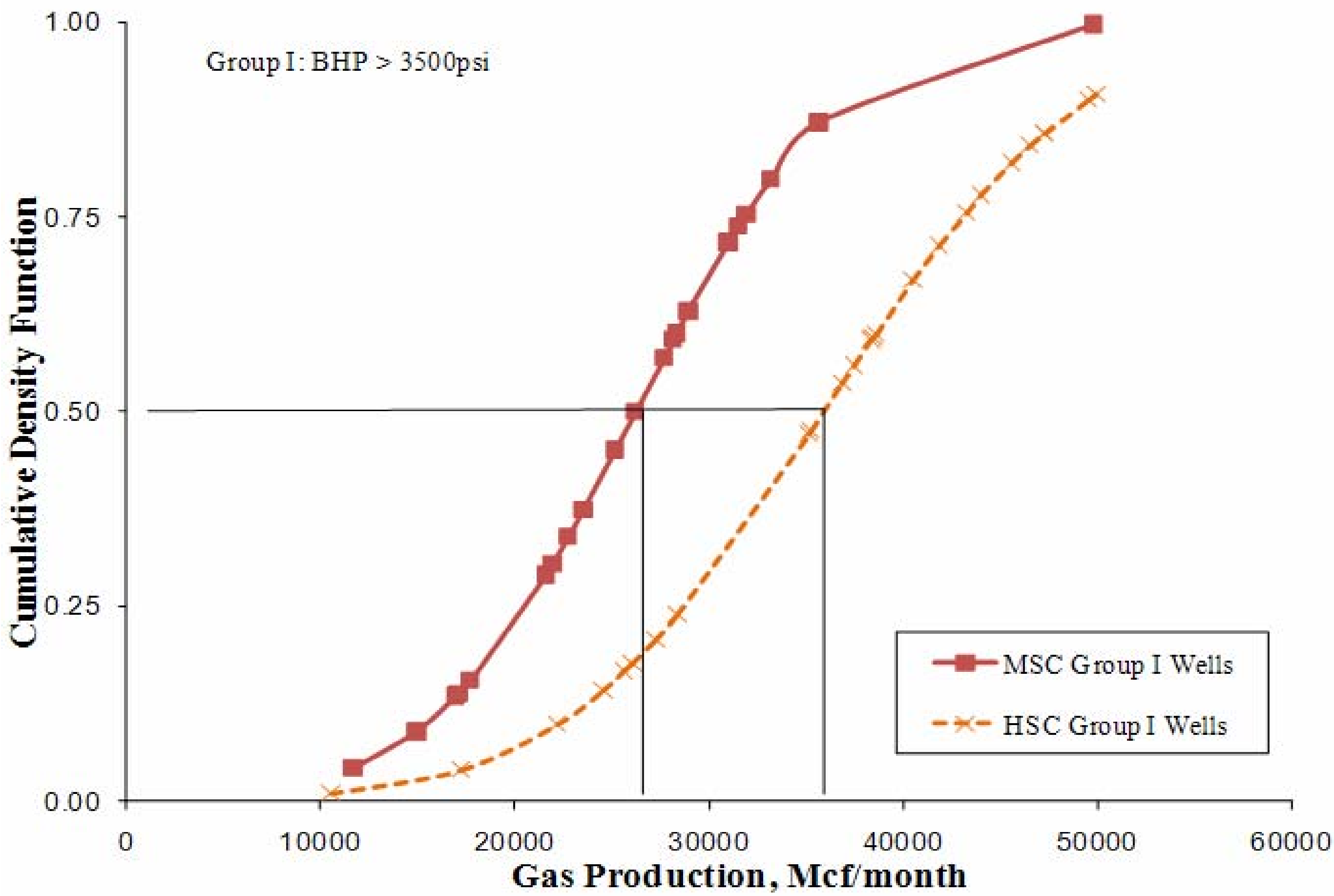

Figure A-2—CDF for Gas Best 3 Months Production Based on Sand Content. Indicates Wells with Higher Sand Content Produce Better.

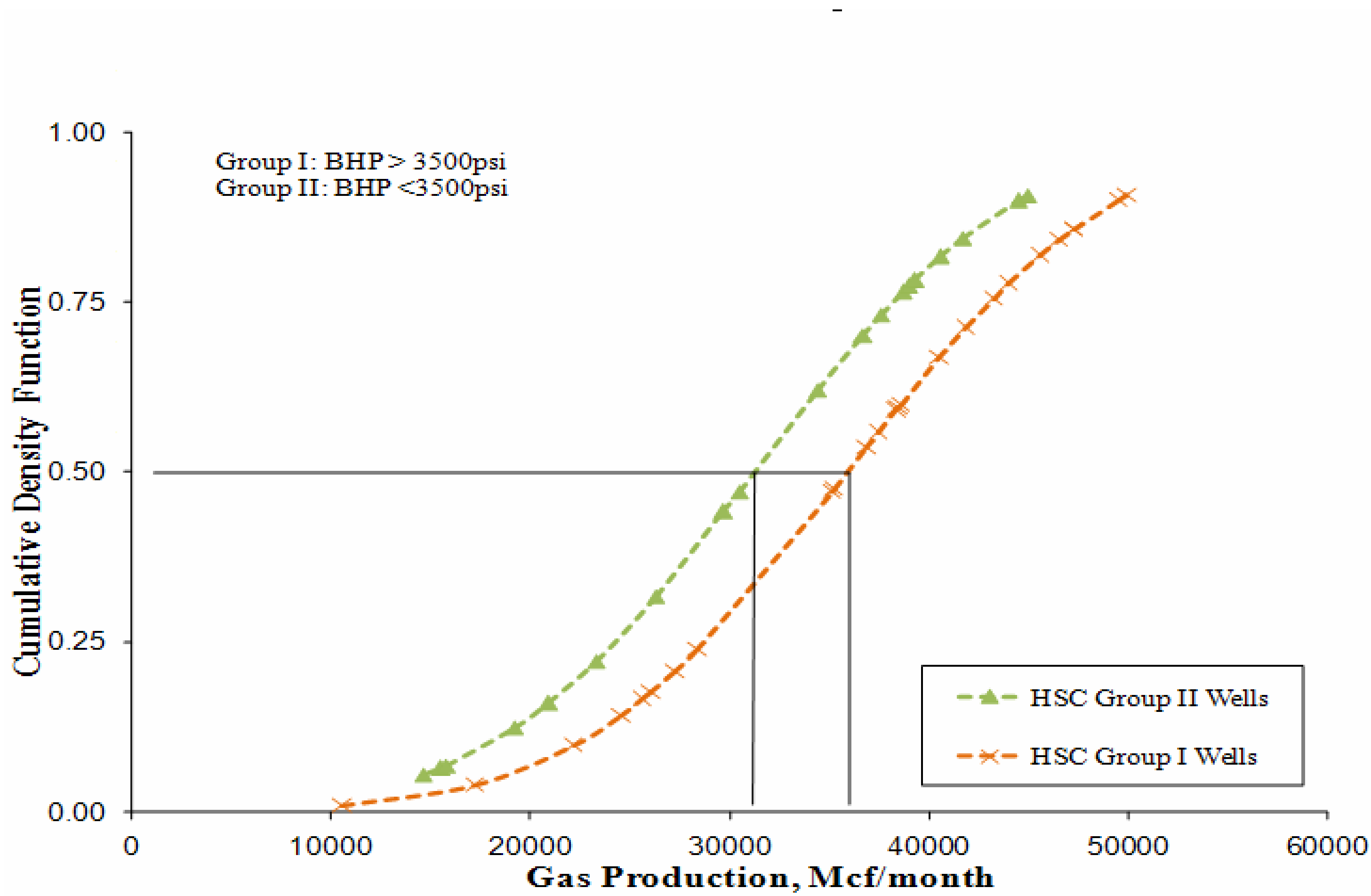

Figure A-3—CDF for Gas Best 3 Months Production Based on Initial Pressure for HSC Wells. Indicate that the High Pressure Wells give Better Production.

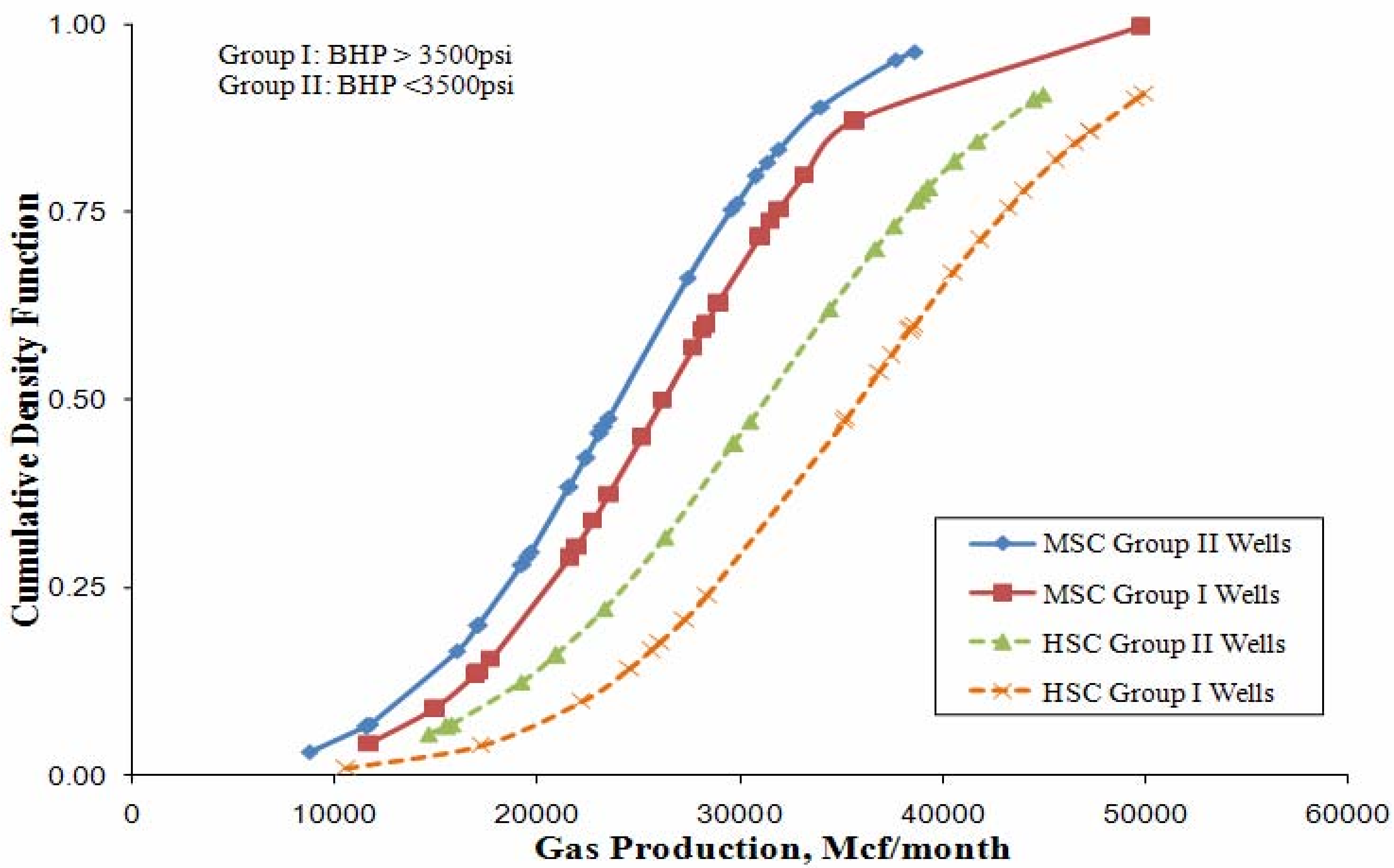

Figure A-4—CDF for Best 3 Months Gas Production for Both Groups and Both Treatments. (Oak Hill)

APPENDIX B

Treatment wise analysis of Elm Grove Field

Test B1: Comparison of means of 5 year cumulative gas production

We compared the 5 year cumulative gas production for the 3 treatments. Data for the hypothesis testing for all the wells are shown in **Table B-1**. The p-value as shown in **Table B-2** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the mean 5 year cumulative gas production was unequal for wells stimulated with Hybrid, Gel and Water fracture treatments with a 90% significance level.

Table B-1—Data for Hypothesis Testing Based upon 5 Year Cumulative Gas Production.

5 Years Cumulative Gas Production	**Fracture Treatment**		
	Hybrid	**Gel**	**Water**
Mean, MMscf	353	260	196
Standard Deviation	153	65	66
Data Points	14	6	5

Table B-2—Results of Hypothesis Testing Based upon 5 year Cumulative Gas Production.

Parameter	**Values**	
	Hybrid Vs Gel	**Hybrid Vs Water**
Rejection Criterion, α	0.1	0.1
Significance Level, p-value	0.0719	0.0067

Figure B -1 is a plot of the cumulative distribution function for 5 year estimated values of cumulative gas production for the 3 treatment types. Hybrid fracture treated wells are on the right side of Gel fracture treated wells. Also Gel fracture treated wells are on the right side of water fracture treated wells. This indicates that the Hybrid fracture treated wells have better 5 year cumulative gas production than the Gel fracture treated wells and Gel fracture treated wells are better than Water fracture wells.

Test B2: Comparison of means of OGIP

We compared the estimated values of OGIP for the 3 treatments. Data for the hypothesis testing for all the wells are shown in **Table-B-3**. The p-value as shown in **Table B-4** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the mean OGIP was unequal for wells stimulated with Hybrid, Gel and Water fracture treatments with a 90% significance level.

Table B-3—Data for Hypothesis Testing Based upon OGIP.

OGIP	**Fracture Treatment**		
	Hybrid	**Gel**	**Water**
Mean, MMscf	849	596	379
Standard Deviation	377	198	289
Data Points	14	6	5

Table B-4—Results of Hypothesis Testing Based upon OGIP.

Parameter	**Values**	
	Hybrid Vs Gel	**Hybrid Vs Water**
Rejection Criterion, α	0.1	0.1
Significance Level, p-value	0.0672	0.0179

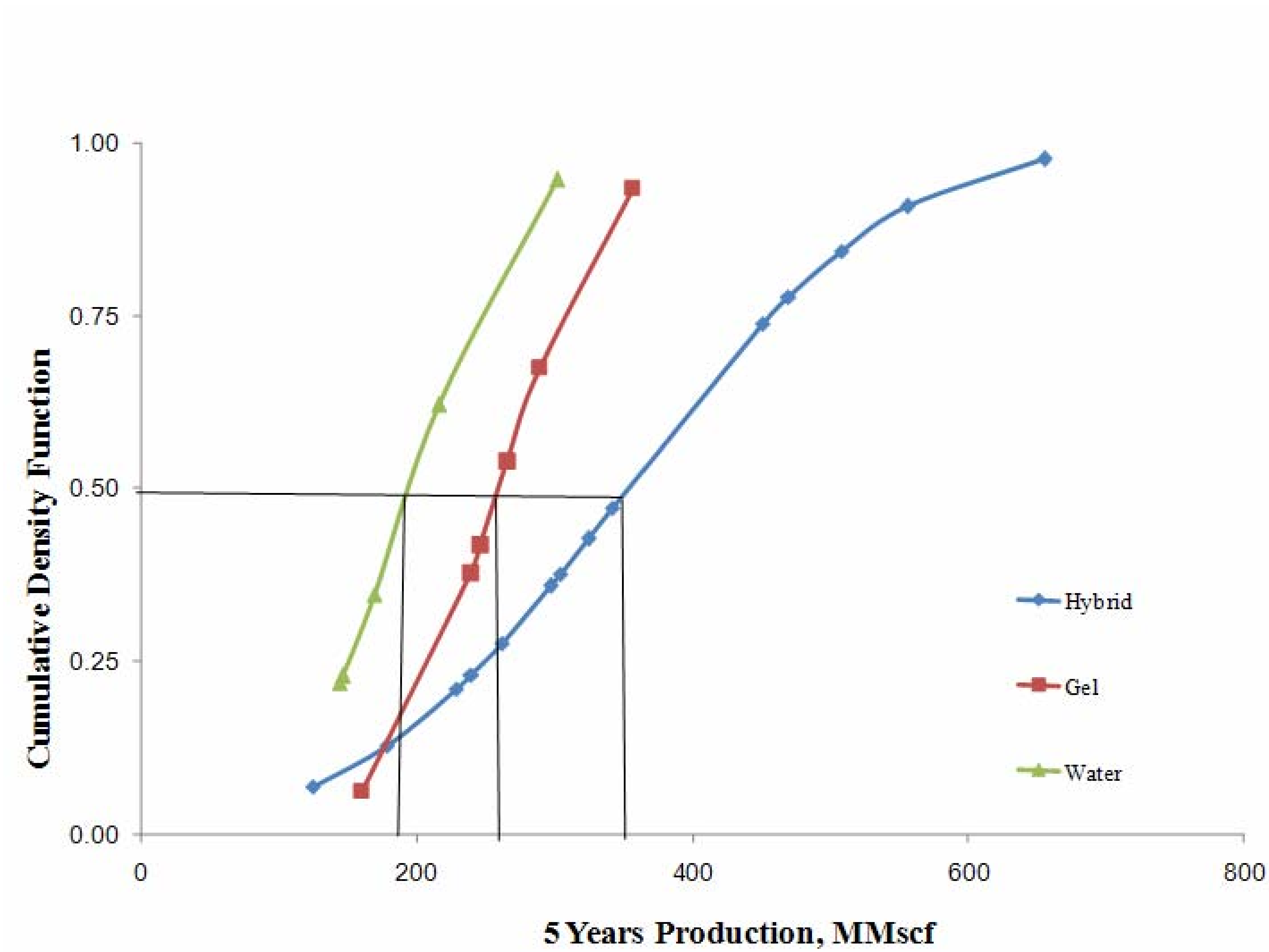

Figure B-1— CDF for 5 Years Cumulative Gas Production Based on Treatment type for Wells in the Elm Grove Field.

Figure B-2 is a plot of the cumulative distribution function for estimated values of OGIP. Hybrid fracture treated wells are on the right side of Gel fracture treated wells. Also Gel fracture treated wells are on the right side of water fracture treated wells. This indicates that the Hybrid fracture treated wells have better 5 year cumulative gas production than the Gel fracture treated wells and Gel fracture treated wells are better than Water fracture treated wells.

Test B3: Comparison of means of Sand Content

We compared the Sand Content for the 3 treatments. Data for the hypothesis testing for all the wells are shown in **Table B-5**. The p-value as shown in **Table B-6** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the OGIP was unequal for wells stimulated with Hybrid, Gel and Water fracture treatments with a 95% significance level.

Table B-5—Data for Hypothesis Testing Based upon Sand Content.

Sand Content	**Fracture Treatment**		
	Hybrid	**Gel**	**Water**
Mean, PPG	1.49	1.20	0.70
Standard Deviation	0.287	0.232	0.106
Data Points	14	6	5

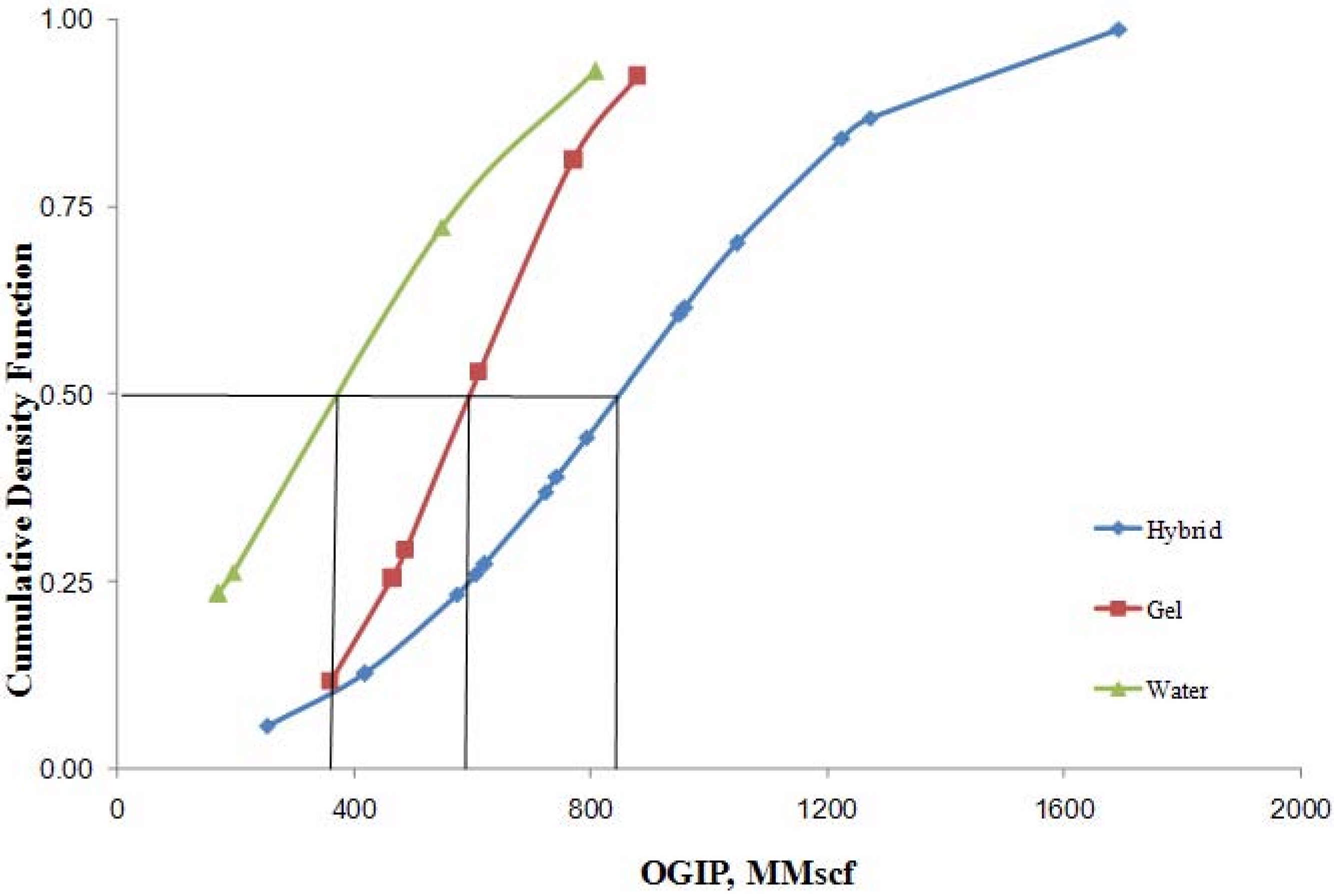

Figure B-2— CDF for OGIP Based on Treatment type in the Elm Grove Field Indicates Hybrid Fracture Treatments are Better.

Table B-6—Results of Hypothesis Testing Based upon Sand Content.

Parameter	**Values**		
	Hybrid Vs Gel	**Hybrid Vs Water**	**Gel Vs Water**
Rejection Criterion, α	0.05	0.05	0.05
Significance Level, p-value	0.03411	0.0000	0.002

Figure B-3 is a plot of cumulative distribution function for OGIP. Hybrid fracture treated wells are on the right side of Gel fracture treated wells. Also Gel fracture treated wells are on the right side of water fracture treated wells. This indicates that the Hybrid fracture treated wells have better 5 year cumulative gas production than the Gel fracture treated wells and Gel fracture treated wells are better than Water fracture treated wells.

Test B4: Comparison of means of Drainage Area

We compared the drainage area for the 3 treatments. Data for the hypothesis testing for all the wells are shown in **Table B-7**. The p-value as shown in Table **B-8** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the mean drainage area was unequal for wells stimulated with Hybrid, Gel and Water fracture treatments with a 95% significance level.

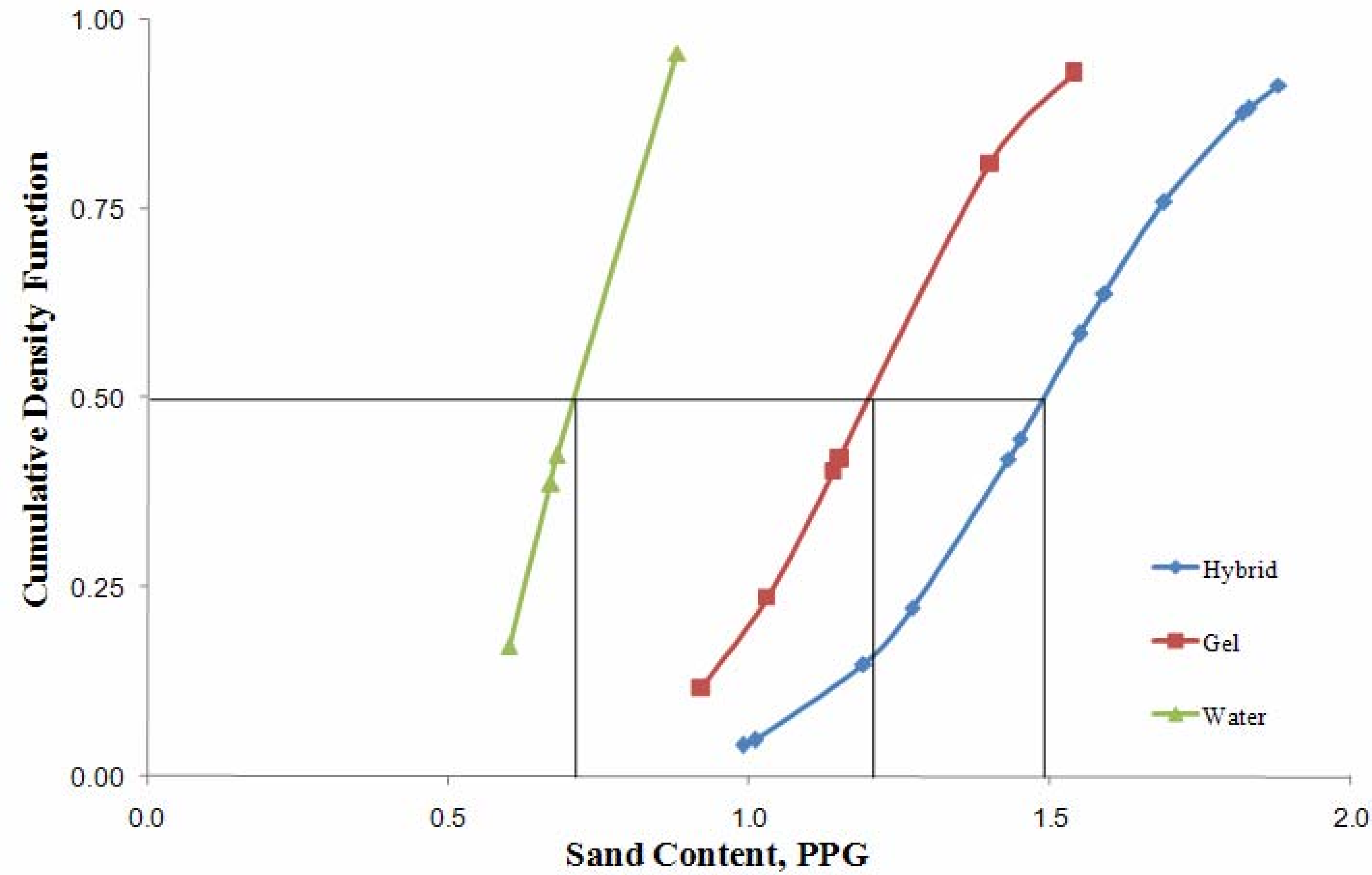

Figure B-3—CDF for 10 Years Cumulative gas Production Based on Treatment Type for Wells in the Elm Grove Field.

Table B-7—Data for Hypothesis Testing Based upon Drainage Area.

Area	Fracture Treatment		
	Hybrid	Gel	Water
Mean, Acre	12.3	8.1	5.0
Standard Deviation	5.7	2.4	3.8
Data Points	14	6	5

Table B-8—Results of Hypothesis Testing Based upon Drainage Area.

Parameter	Values	
	Hybrid Vs Gel	Hybrid Vs Water
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.0338	0.0081

Figure B-4 is a plot of the cumulative distribution function for drainage area. Hybrid fracture treated wells are on the right side of Gel fracture treated wells. Also Gel fracture treated wells are on the right side of water fracture treated wells. This indicates that the Hybrid fracture treated wells drain more area than gel fracture treated wells and gel fracture treated wells drain more area than water fracture treated wells.

Test B5: Comparison of means of Fracture half-length

We compared the fracture half-lengths for the 3 treatments. Data for the hypothesis testing for all the wells are shown in **Table B-9**. The p-value as shown in **Table B-10** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates

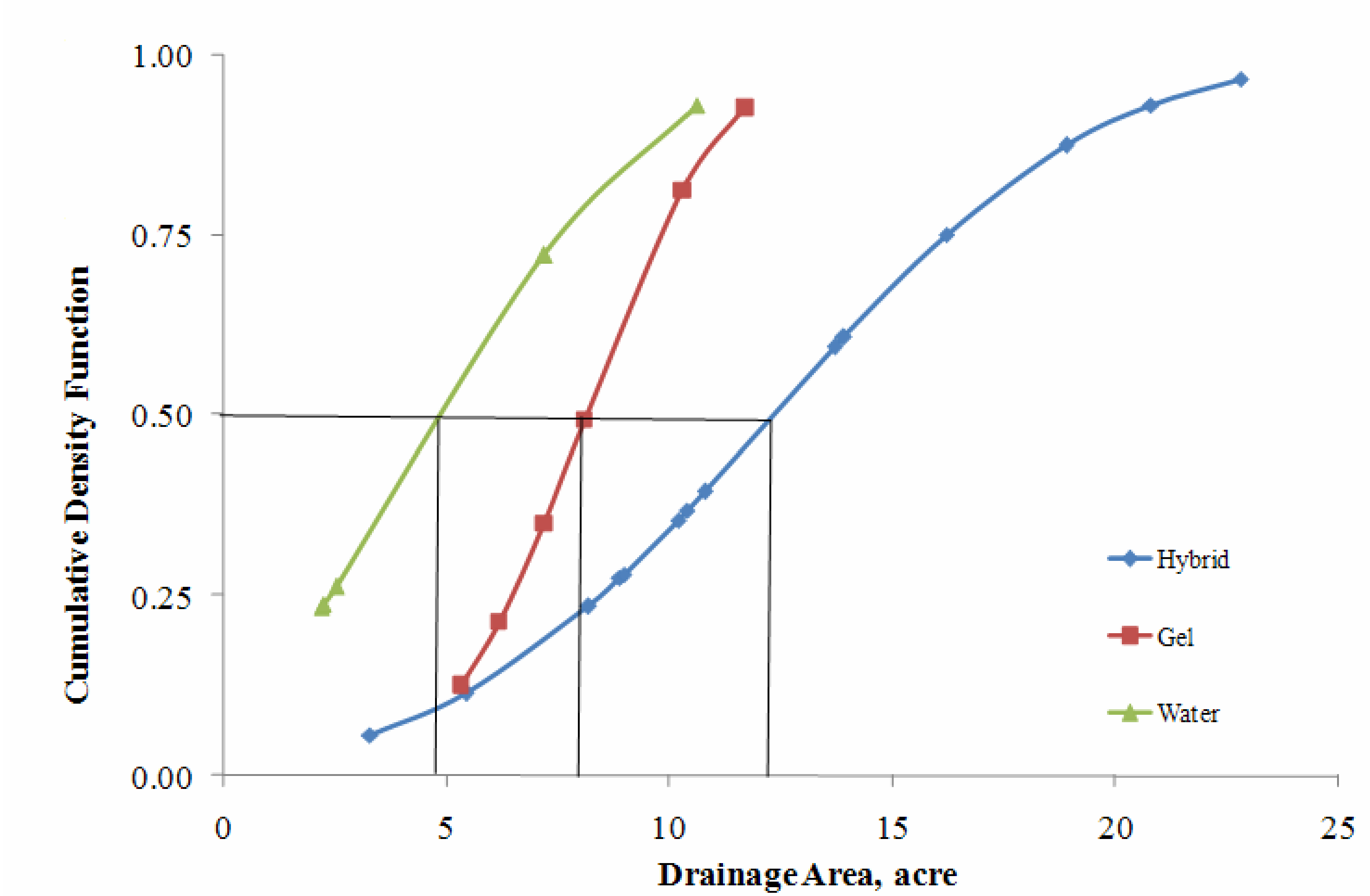

Figure B-4— CDF for Drainage Area based on Treatment Type. Indicates Water Fractures have the Least Drainage Area.

that the mean half-length was unequal for wells stimulated with Hybrid, Gel and Water fracture treatments with a 95% significance level.

Table B-9—Data for Hypothesis Testing Based upon Fracture Half-Length.

Half-Length	Fracture Treatment		
	Hybrid	**Gel**	**Water**
Mean, ft	309	288	171
Standard Deviation	73	36	42
Data Points	14	6	5

Table B-10—Results of Hypothesis Testing Based upon Fracture Half-Length.

Parameter	Values	
	Water Vs Hybrid	**Water Vs Gel**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.0002	0.0012

Figure B-5 is a plot of the cumulative distribution function for OGIP. Hybrid fracture treated wells are on the right side of Water fracture treated wells. Also Gel fracture treated wells are on the right side of water fracture treated wells. This indicates that the Hybrid fracture treated and Gel fracture treated wells have better fracture half-lengths. However, the gel fracture treated and hybrid fracture treated wells have comparable fracture half-lengths.

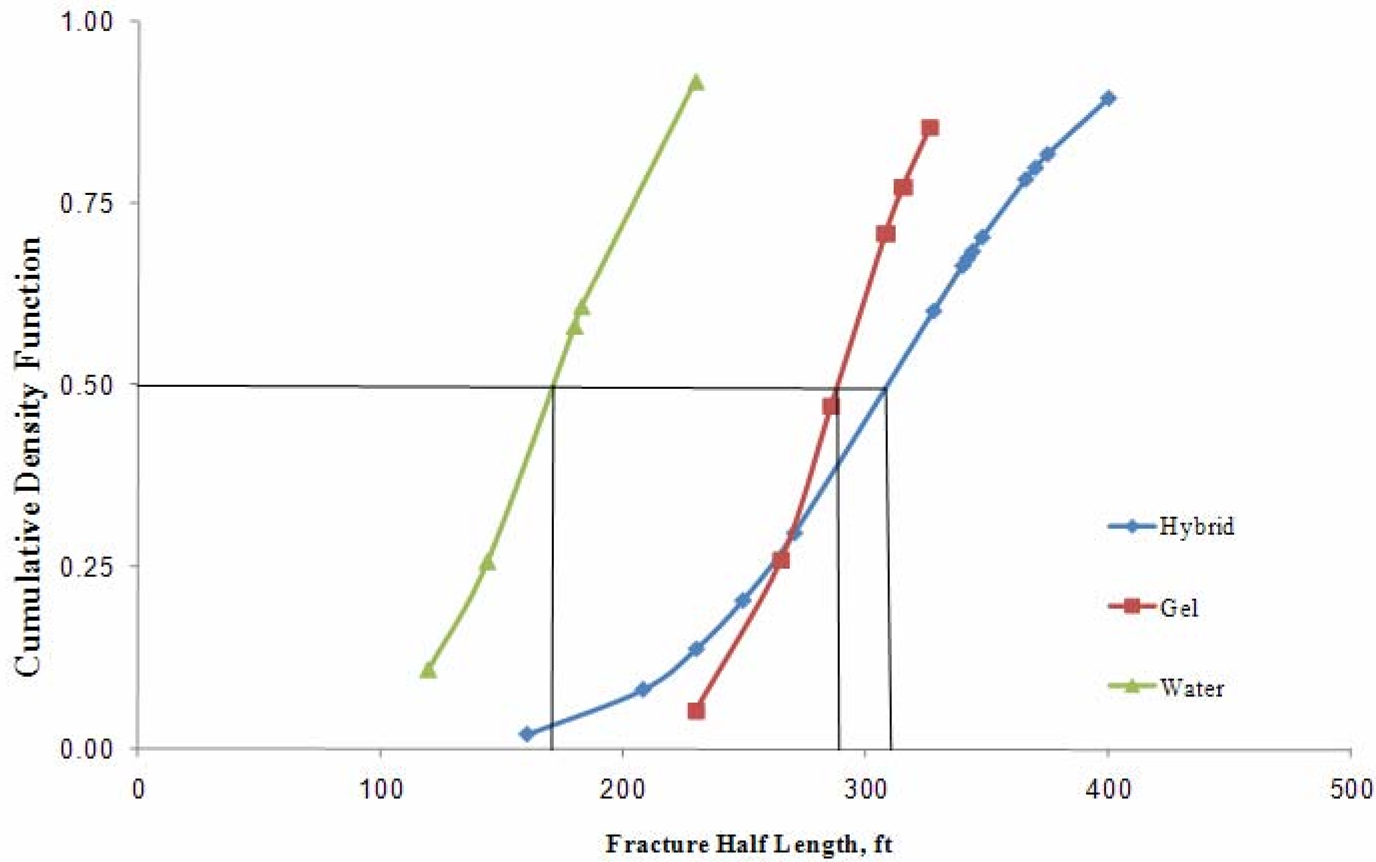

Figure B-5—CDF for Fracture Half-Length based on Treatment Type (Elm Grove Field). Indicates that Hybrid Fracture and Gel Fracture Treatments are Larger and have Comparable Half-Lengths while Water Fracture Treatments are smaller.

APPENDIX C

Region wise analysis of Elm Grove Field

Test C1: Comparison of means of 5 year cumulative gas production

We compared the 5 year cumulative gas production for the 3 regions. Data for the hypothesis testing for all the wells are shown in **Table C-1**. The p-value as shown in **Table C-2** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the mean 5 year cumulative gas production was unequal for Western, Northern and Central regions with a 95% significance level.

Table C-1—Data for Hypothesis Testing Based upon 5 Year Cumulative Gas Production.

5 Year Cumulative gas Production	**Region**		
	North	**Central**	**West**
Mean, MMscf	258	223	456
Standard Deviation	76	69	142
Data Points	8	10	7

Table C-2—Results of Hypothesis Testing Based upon 5 Year Cumulative Gas Production.

Parameter	**Values**	
	West Vs North	**West Vs Central**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.0093	0.0038

Figure C-1 is a plot of the cumulative distribution function for 5 year cumulative gas production for the 3 regions. Western region wells are on the right side of Northern and Central region wells. Also we observe that the mean of the western region wells is far better than the other two regions. This indicates that the Western region wells have far better 5 year cumulative gas production than the Northern and Central region wells. While Northern wells are just marginally better than the central region wells.

Test C2: Comparison of means of 10 year cumulative gas production

We compared the 10 year estimated values of cumulative gas production for the 3 regions. Data for the hypothesis testing for all the wells are shown in **Table C-3**. The p-value as shown in **Table C-4** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the mean 10 year cumulative gas production was unequal for Western, Northern and Central regions with a 95% significance level.

Table C-3—Data for Hypothesis Testing Based upon 10 Year Cumulative Gas Production.

10 Year Cumulative Production	**Region**		
	North	**Central**	**West**
Mean, MMscf	334	300	635
Standard Deviation	103	111	190
Data Points	8	10	7

Table C-4—Results of Hypothesis Testing Based upon 10 Year Cumulative Gas Production.

Parameter	**Values**	
	West Vs North	**West Vs Central**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.0048	0.0025

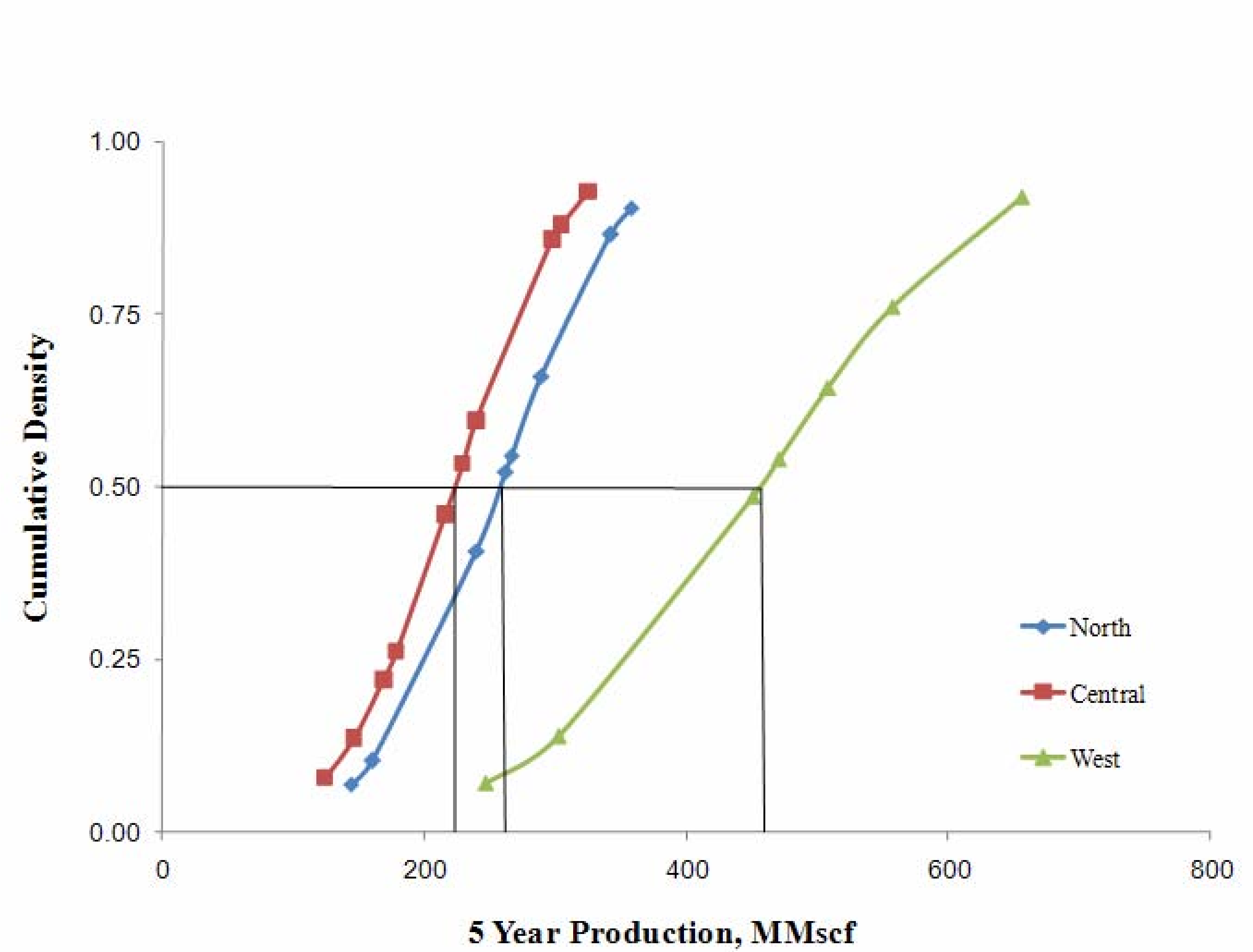

Figure C-1—CDF for 5 Year Cumulative Gas Production based on different regions of the Elm Grove Field.

Figure C-2 is a plot of the cumulative distribution function for 10 year cumulative gas production for the 3 regions. Similar to the 5 year cumulative gas production we observe that the Western region wells have far better 5 year cumulative gas production than the Northern and Central region wells. While Northern wells are just marginally better than the central region wells.

Test C3: Comparison of means of OGIP

We compared the estimated values of OGIP for the 3 regions. Data for the hypothesis testing for all the wells are shown in **Table C-5**. The p-value as shown in **Table C-6** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the mean OGIP was unequal for Western, Northern and Central regions with a 95% significance level.

Table C-5—Data for Hypothesis Testing Based upon OGIP.

OGIP	**Region**		
	North	**Central**	**West**
Mean, MMscf	539	528	1110
Standard Deviation	219	267	320
Data Points	8	10	7

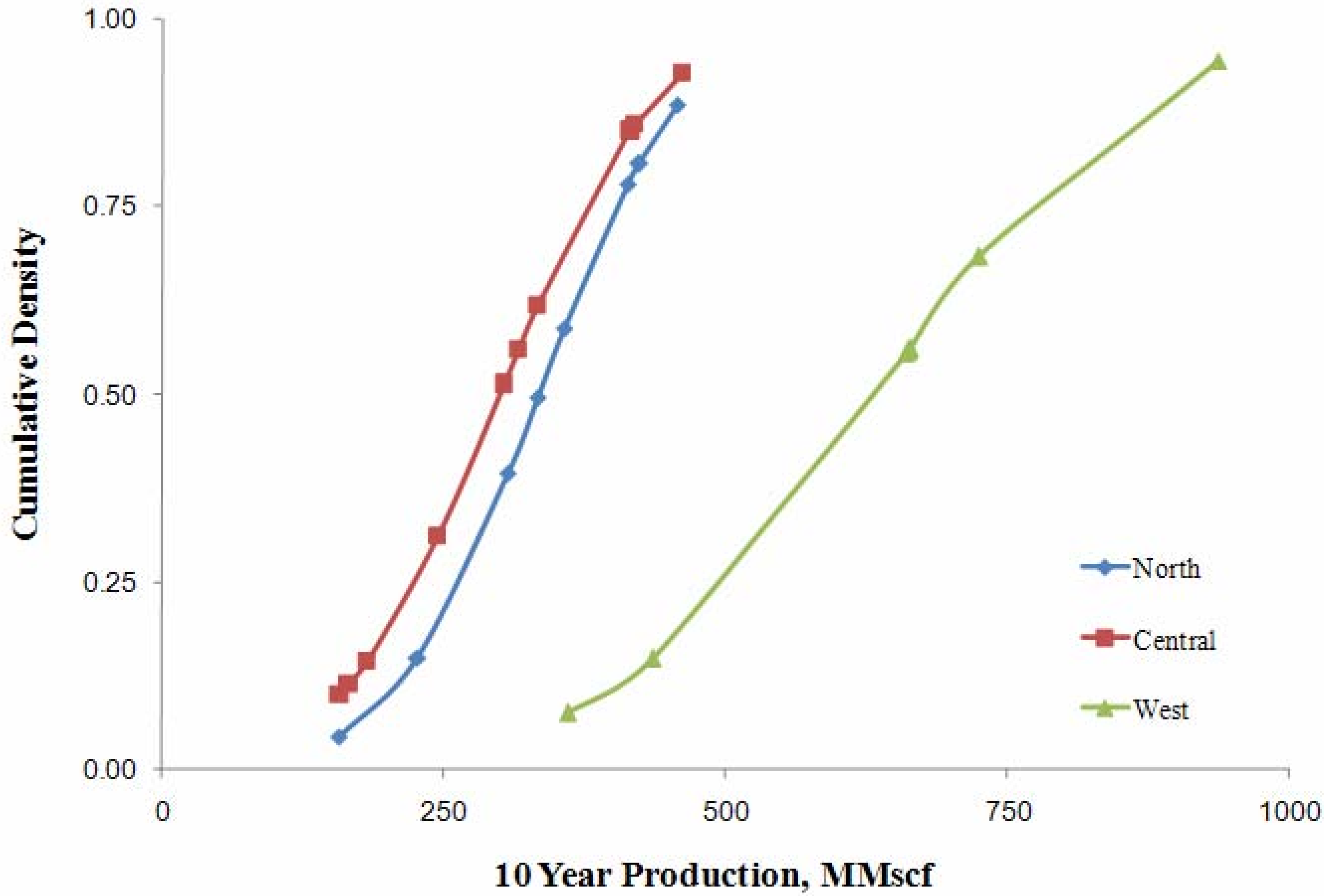

Figure C-2—CDF for 10 Year Cumulative Gas Production based on Different Regions of the Elm Grove Field.

Table C-6—Results of Hypothesis Testing Based upon OGIP.

Parameter	Values	
	West Vs North	West Vs Central
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.0024	0.0021

Figure C-3 is a plot of the cumulative distribution function for OGIP for the 3 regions. Similar to the OGIP we observe that the Western region wells have far better OGIP than the Northern and Central region wells. But we observe that Central and the Northern region curves overlay each other so they have similar OGIP.

Test C4: Comparison of means of Drainage Area

We compared the Drainage Area for the 3 regions. Data for the hypothesis testing for all the wells are shown in **Table C-7**. The p-value as shown in **Table C-8** was less than the rejection criterion, α, so we can reject the null hypothesis. This indicates that the mean drainage was unequal for Western, Northern and Central regions with a 95% significance level.

Table C-7—Data for Hypothesis Testing Based upon Drainage Area.

Drainage Area	Region		
	North	Central	West
Mean, acre	7.5	7.3	16.2
Standard Deviation	3.0	3.9	4.9
Data Points	8	10	7

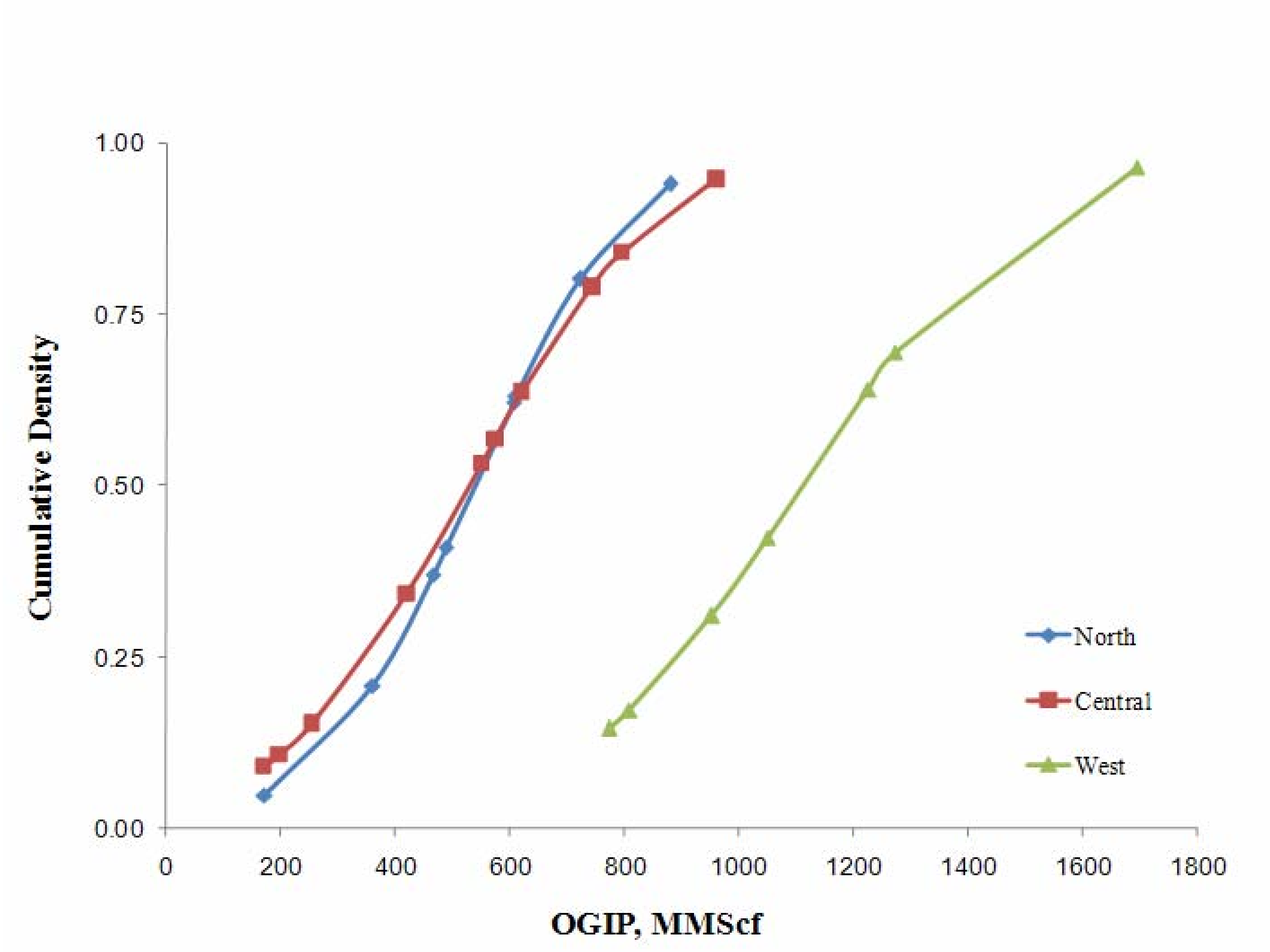

Figure C-3—CDF for OGIP based on Different Regions of the Elm Grove Field.

Table C-8—Results of Hypothesis Testing Based upon Drainage Area.

Parameter	Values	
	West Vs North	**West Vs Central**
Rejection Criterion, α	0.05	0.05
Significance Level, p-value	0.0023	0.0019

Figure C-4 is a plot of the cumulative distribution function for drainage area for the 3 regions. We observe that the Western region wells have far better drainage area than the Northern and Central region wells. But we observe that Central and the Northern region curves overlay each other so they have similar drainage.

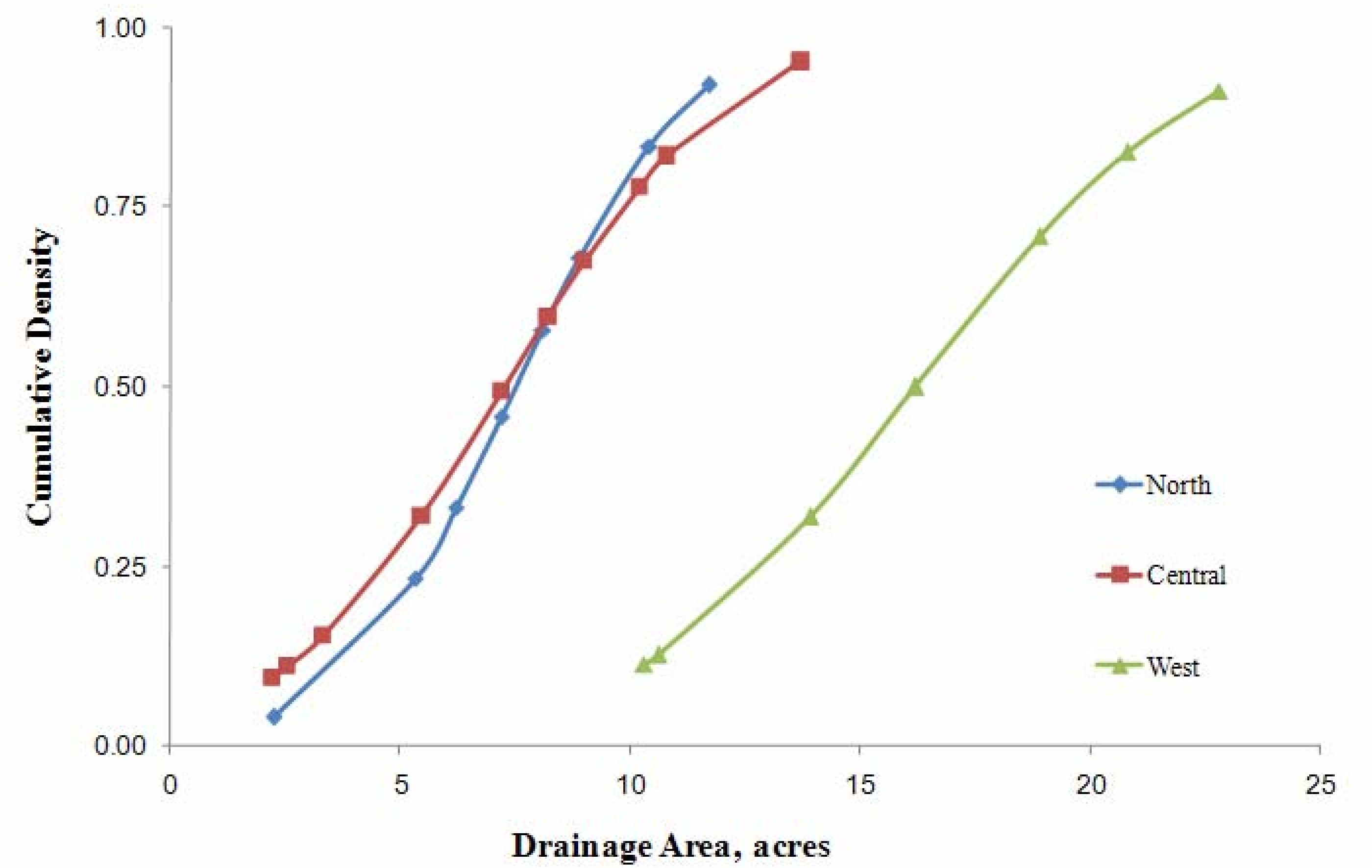

Figure C-4—CDF for Drainage area based on Different Regions of the Elm Grove Field.

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