Hydraulic Fracture Imaging

Final Report
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Disclaimer

Abstract

Hydraulic fracturing is used as a completion method on the vast majority of tight sand well completions throughout the Appalachian Basin. Successful stimulations are highly dependent on the geometry of the created fracture. Many subsurface variables affect the growth of the fracture. The consequence of this being that the ultimate configuration of a hydraulic fracture is largely unknown. This makes it virtually impossible to optimize fracture design and maximize efficient gas recovery.

The goal of this project is to apply the latest fracture imaging technology to enable fracture designers the ability to evaluate the actual results of their design. Understanding the actual dimensions and configuration of created hydraulic fractures will maximize resource recovery through optimal well spacing and cost effective fracture design. There are many software based computer models on the market but without "calibration" they can only be applied in theory as a guide for fracture design. Imaging of hydraulic fractures will enable fracture designers to properly calibrate these fracture models in order to more precisely evaluate treatment design, execution, and effectiveness.

This project for the first time enabled an Appalachian Basin operator to effectively determine these vital aspects of hydraulic fracture creation and geometry.

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Introduction

The Upper Devonian sandstones of the Appalachian Basin are an important and well documented natural gas resource. Extensively drilled and exploited since Drake's original discovery well in 1859, these reservoirs include but are not limited to the Venango Group sandstones, the Bradford Group sandstones, and the Elk Group. Tens of thousands of wells produce from these formations throughout the Appalachian Basin, primarily in Pennsylvania and West Virginia. The generalized producing trend is shown in Figure 1. The majority of these producing zones are tight gas sands and as such require enhancement primarily through the use of hydraulic fracturing. The type of fracture stimulation utilized varies widely, from conventional gelled water fracs to nitrogen foam fracs, to crosslinked gel fracs. Stimulation selection criteria is commonly based upon what has been deemed most successful in the past in an area by any given operator. This success is usually inferred through trial and error and based strictly upon production response and dictated by economics. Little or no concrete knowledge exists regarding the actual created and propped fracture geometries resulting from the fracturing process. These unknowns include fracture height, fracture length, and azimuth. To further complicate any attempt to determine these parameters via production testing is the fact that most wells are completed in multiple zones using the ball and baffle staging process.

While computer fracture modeling is frequently used as a tool in attempting to optimize fracture design, many assumptions must be made with regard to the rock mechanics which ultimately dictate fracture geometry. Accurate measurements of such important parameters as Poisson's Ratio, Young's Modulus, fracture toughness, formation stresses and most importantly stress variations between adjacent formations are all too seldom available for use as inputs in modeling. Most commonly, the fracture models are used to match pressures gathered from actual treatments and thereby back into a best guess at the geometry created by the treatment. Once a reasonable pressure match is created, the predicted geometries are commonly accepted at face value. While this may (or may not) result in a valid representation of the fracture, what is still lacking is any true knowledge of the fracture direction or azimuth. This component of geometry is vital to the optimization of reservoir development and ultimate recoveries.

Microseismic imaging of hydraulically created fractures can answer many of these uncertainties surrounding created fracture geometry. The created fracture dimensions can be observed, measured, and ultimately correlated with variables in the stimulations such as volumes, rates, and fluid selection. Previously unknown factors such as fracture asymmetries, preferential fracture growth in multiple zone completions, unforeseen fracture complexities such as natural fracturing, and the effects of multiple stage completions from the same wellbore can be observed. Ultimately, improvements in the fracturing process can be made based upon concrete data.

In this report, the results of microseismic imaging of hydraulic fractures in Great Lakes Energy Partners' Hunker Field in southwestern Pennsylvania are presented. This project produced the first microseismic images of fracture treatments in the Upper Devonian Sands of the Appalachian Basin. The field is in Fayette County Pennsylvania and is a typical case of development drilling in the basin. Zones treated and imaged included the Fifth Sand, the Lower Bayard, the Speechley, and the First Bradford.

Executive Summary

This project involves bringing a technology into the Appalachian Basin to image hydraulic fractures as they are being created. It will also develop the evaluation and engineering techniques to apply the information gained to the design of hydraulic fractures for marginal wells in the Basin. At present there is no direct evidence which proves the actual fracture dimension and geometry for any of the many regional stripper well reservoirs that are stimulated by hydraulic fracturing.

Fracture imaging technologies have been used in more prolific areas of the world but have not been applied in this region due to several factors. The engineering evaluations to plan for the use of the process are a tall hurdle for the economic realities that control technology application on the stripper wells that so badly need the data that can be gained. The equipment and engineering support is located in the Western US and is prohibitively expensive to mobilize and utilize in this area.

The goal of this project is to use this available technology to image hydraulic fractures and demonstrate how the engineering process is done so that it can be applied to other marginal stripper wells in the Basin. Understanding the geometry of created hydraulic fractures will help operators answer many questions that affect their every day economics and profitability including: well spacing and locating for maximum resource recovery, fracture design and application parameters such as job size and cost, determining if all of the potential pay zones have been effectively treated by the fracture stimulation treatment they are utilizing. This could have major implications for the many stripper wells in the basin if it is found that potential exists for recompletion of unstimulated intervals.

Many operators utilize computer simulation models to help design their fracture stimulations. Unfortunately there is no data available to calibrate the models and validate their recommendations. One of the first contributions from this project will be the calibration of regional fracture models with actual data. The data gleaned from this project is currently being utilized to improve fracture modeling and design in the Appalachian Basin.

The project has involved preliminary engineering reviews and design as well as the actual imaging of hydraulic fractures with microseismic imaging technology. A total of twelve fracture stages in three separate wells were successfully imaged.

Experimental

Microseismic fracture mapping was used to image hydraulic fracture growth in three wells completed in the Upper Devonian sand/shale sequence of southwestern Pennsylvania. Microseismic fracture mapping provides an image of the fractures by detecting microseisms or micro-earthquakes that are triggered by shear slippage on bedding planes or natural fractures adjacent to the hydraulic fracture. The location of the microseismic events is obtained using a downhole receiver array that is positioned at the same depth of the fracture in an offset wellbore. More specifically, the microseisms are detected with multiple transducers deployed on a wireline array in the offset wellbore. This multi-level vertical array of receivers is used to locate the microseisms. The data is relayed to the surface where it is collected and analyzed to yield mapping of the hydraulic fracture geometry (height and length) and azimuth.

Fracture treatments have been performed on thirteen fracture treatments in three wells owned and operated by Great Lakes Energy Partners. The microseismic data was successfully collected by Pinnacle technologies and is being analyzed. This analysis includes fracture model calibration utilizing this newly acquired data.

Results and Discussion

Results of Imaging

Figure 2 shows a map view presentation of the Linden Hall wells and plots the locations of the microseismic events recorded during the project. The microseismic array was installed in Linden Hall #2, labeled MS Tools. From this view, the preferred azimuths of fracture growth and the lengths of the fractures created can be seen. It is apparent from this plot that the preferred direction of fracture growth is in the southwest - northeast direction from the wellbore. On average all stages mapped grew along an azimuth of approximately N50E. Fracture azimuths for all stages mapped are listed in Table 1.

What cannot be seen in the mapview plot however, is the height component of the fracture geometry or the lengths of the fractures created during the separate frac stages. To see these features, a sideview plot such as Figure 3 can be generated. From this plot (from the Linden Hall #3 well) numerous items of interest can be picked out. Events corresponding to each frac stage can be viewed. The first stage, indicated by the blue markers, appears to have grown preferentially to the southwest. The second stage (red markers) seems to have been influenced by the first stage and grew preferentially to the northeast. This is presumably due to the effects of "stress shadowing," an alteration of the stressfield due to placement of the first fracture. In other words, the fracture created during the first stage has increased the rock stress and has influenced the fracture placed in the second stage to propagate primarily in the opposite direction.

It is also readily apparent that the created fractures by no means stayed within the perforated sand layers. The sands are indicated by the layers drawn on the chart and correspond to the gamma ray curve. From this it can be seen that all stages experienced significant growth both upward and downward. It should be remembered however that microseismic imaging **does not** indicate proppant placement, it is a measurement of created fracture dimensions.

Within the cloud of colored markers indicating the fracture created during a particular stage, a discordant marker or two corresponding with those of the next stage appear, i.e. a red marker lies within the blue markers, several green within the reds, etc. This is due to the fact that while pumping the frac ball to the baffle between zones on a multiple stage well, the wellbore fluid is displaced into the previously completed, nonisolated stage until the fracball is seated, the new fracture is initiated and fluid is redirected into the new perforations. A similar situation was observed in the stimulation of the Linden Hall #4 in which a ballout was performed prior to the third fracture stage. As the perfballs were displaced, reactivation of the prior stage was observed. These microseismic events should not be interpreted as being a true component of fracture height.

It can be seen that the third stage exhibited both significant downward growth as well as preferential growth to the northeast. While the downward height growth is indisputable, caution must be used in assuming that the single wing to the northeast dominates this fracture. By referring to the mapview presented in Figure 2, it is seen that these events were advancing toward the receivers in the observation well. While corresponding events may have been occurring in the opposite direction, these may have been masked by the northeasterly advancing fracture noise. This interpretation differs from the first stage mapped in that during the first stage, the bulk of the events received were to the southwest or away from the observation well. Few events were recorded directly between the treatment well and the observation well thus indicating preferential growth to the southwest during that stage.

The fourth and fifth stages appear to significantly overlap each other and in fact events recorded during each of these stages were detected within the region which was stimulated during the third stage. Stimulation of all three of these upper zones may in fact be optimized by perforating and completing all three zones together in a single larger fracture stage rather than via traditional multiple stages. A similar overlapping of stages was also observed in each of the other two wells imaged.

A summary of all treatment volumes (fluid and proppant) and created fracture geometries (height, half-length, and azimuth) are listed in Table 1. Figures 4 and 5 illustrate the relationships between stage volumes and resulting fracture height and length. While there does not appear to be a 1:1 relationship between treatment volume and created geometry, in both cases it can be generally stated that with increasing volume comes both increasing fracture height and length. Further, it was observed that on average the fracture half- length is a mere 20% greater than the fracture height. This is a direct indication of the lack of stress contrast between layers and a resultant lack of containment.

Implications For Fracture Model Calibration

One of the most significant benefits resulting from directly measuring fracture geometry is the ability to calibrate and verify fracture computer modeling. Modeling is commonly used in predicting and evaluating the effects of design changes. While all models have standard default values for critical rock properties which ultimately determine fracture geometry, without calibration of these parameters, the veracity of the results generated by models can be questioned.

As an example of how fracture imaging can be used in calibrating a model, the second stage fraced in the Linden Hall #4 well has been pressure matched using commonly accepted methods. The actual treatment data was collected and imported into a commercially available fracturing simulator. The simulator was then used to model the created fracture using actual treating pressure, pump rates, and volumes. In order to create a pressure match, several of the default parameters were adjusted until a reasonable pressure match was obtained. The actual treatment data and the pressure match are shown in Figure 6.

Figure 7 shows the plot of microseismic events generated during the fracture treatment. It should be noted that several events appeared well below the main body of the fracture that actually occurred while the ball was being pumped which correspond to fluid reentering the perforations of the lower stage. Figure 8 is an illustration of the created fracture profile generated after calibration of the simulator. The created geometry is a good match to the data collected during the microseismic mapping. The created fracture height predicted by the model is 588 feet versus

600 feet plotted during mapping. The model predicts a half length of 373 feet while fracture mapping showed 400 feet of half-length.

One aspect of fracture geometry which cannot be addressed by modeling is the phenomenon of fracture asymmetry. Referring back to Figure 3, it can be clearly seen that asymmetrical fracture growth can and does occur. It should always be remembered and taken into consideration that reservoirs such as those being discussed here are rarely if ever homogeneous as is commonly assumed in modeling and engineering. For this reason, direct observation of fracture complexity and calibration of models using microseismic imaging can be an invaluable tool in stimulation optimization.

Conclusions

1) The dominant maximum horizontal stress direction (the direction in which the fracture grows) is roughly N50°E.
2) Fractures pumped in closely placed stages can and do overlap. Stimulation efficiency can potentially be enhanced by combining such zones and stimulating together in a single stage.
3) Fracture containment can be poor. Some zones can exhibit extreme upward and/or downward growth.
4) The effectiveness of fracture modeling can be enhanced through incorporation of microseismic data in model calibration.
5) Fracture asymmetry can occur due to a previously placed fracture altering the stressfield.
6) Procedures performed on a stage may affect previously stimulated nonisolated lower stages. (i.e. The pumping of frac balls or perfballs.)
7) Microseismic mapping can be successfully applied to monitor and optimize hydraulic fracture stimulations in the Devonian Sands.

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Graphical Materials

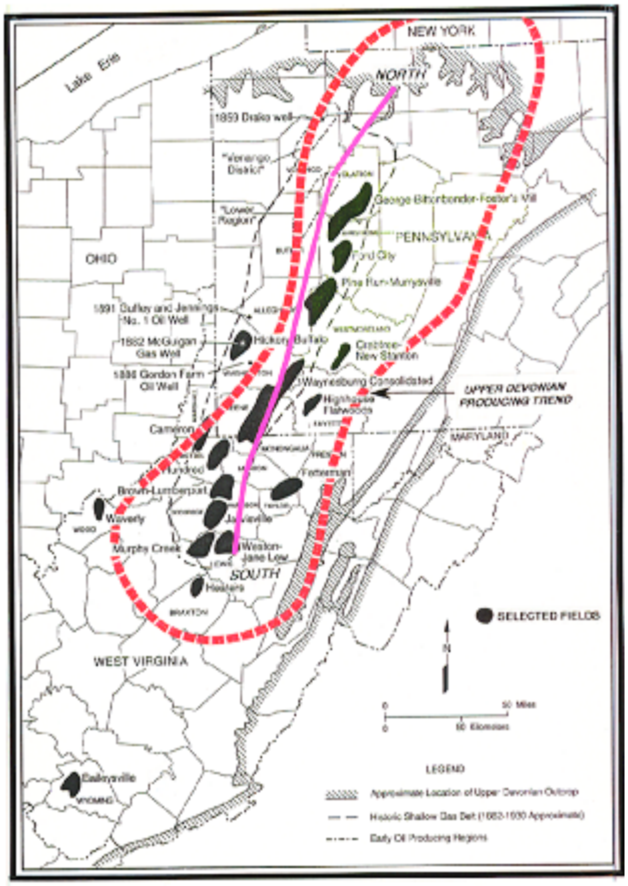

Figure 1 – Appalachian Basin Upper Devonian Trend

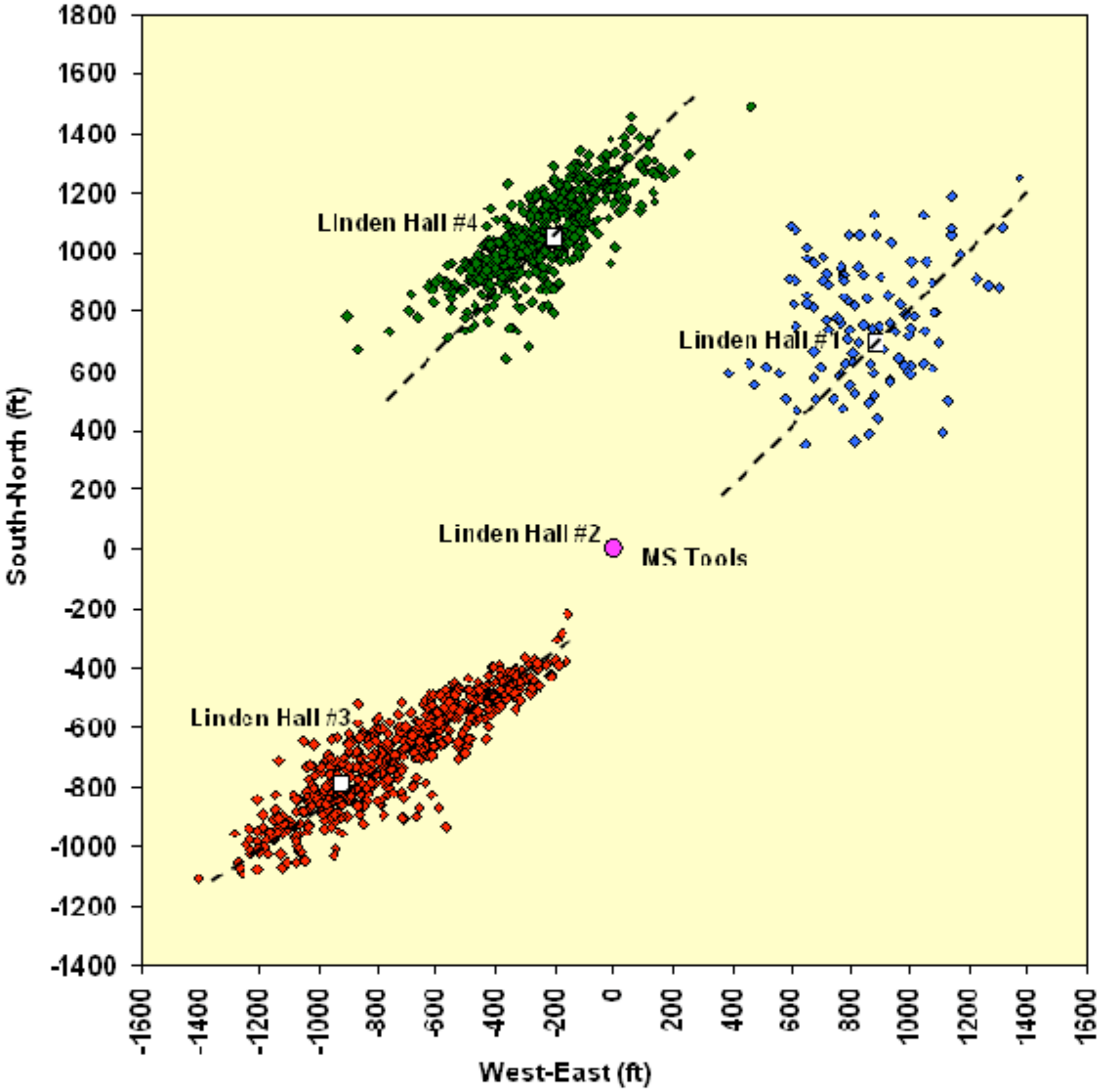

Figure 2 – Map View of Study Wells and Microseismic Events Detected

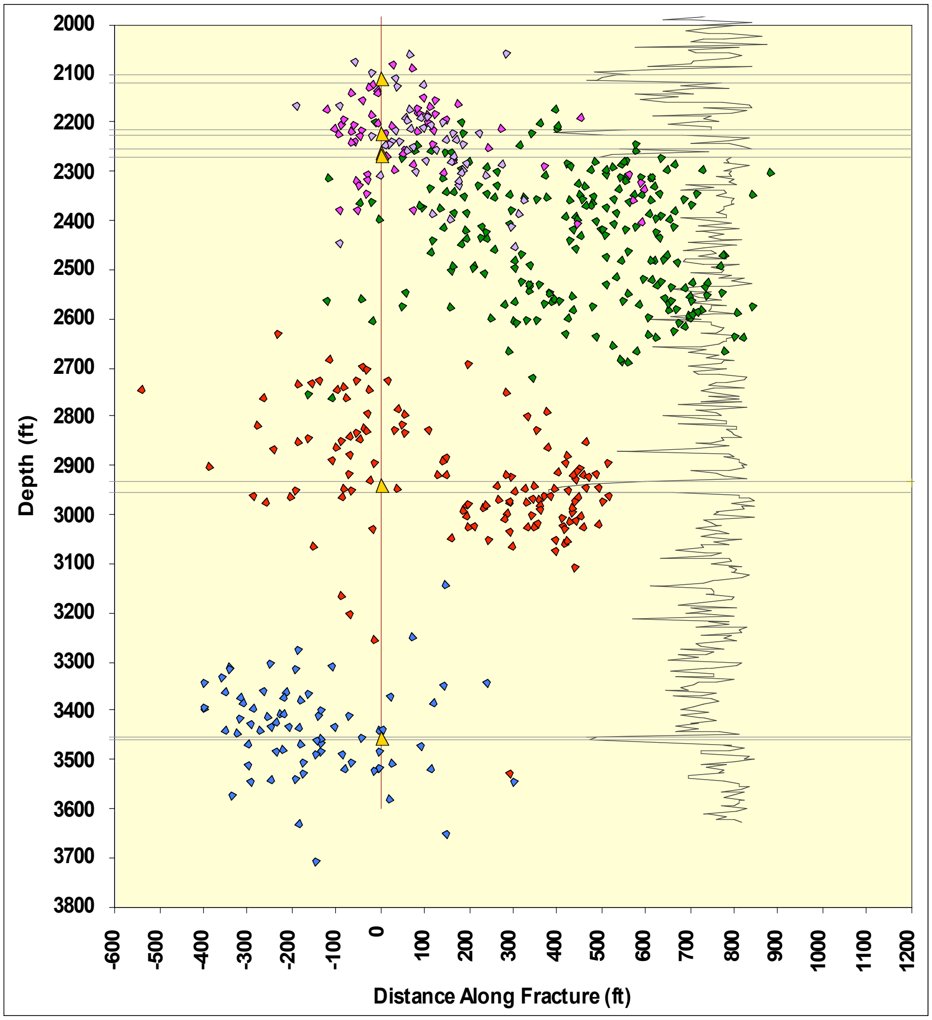

Figure 3 – Side View of Microseismic Events Detected During Stimulation of Linden Hall #3

Stage 1 Height Growth = 400 Feet, Half Length = 400 Feet, Perforated Interval = 11 Feet
Stage 2 Height Growth = 424 Feet, Half Length = 500 Feet, Perforated Interval = 8 Feet
Stage 3 Height Growth = 480 Feet, Half Length = 900 Feet, Perforated Interval = 13 Feet
Stage 4 Height Growth = 300 Feet, Half Length = 320 Feet, Perforated Interval = 51 Feet
Stage 5 Height Growth = 380 Feet, Half Length = 300 Feet, Perforated Interval = 12 Feet

		Volume	Proppant	Height	Half Length	Azimuth
LH#1	Stage1	18,889 gallons	30,500 lbs	206 feet	200 feet	N49W
	Stage 2	19,653	33,800	444	500	N45E
	Stage 3	18,140	34,300	300	300	N40W
LH#3	Stage1	28,935 gallons	56,700 lbs	400	400	N55E
	Stage 2	35,865	51,000	424	500	N55E
	Stage 3	33,817	48,000	480	900	N59E
	Stage 4	26,352	30,000	300	320	N55E
	Stage 5	36,819	52,000	380	300	N50E
LH#4	Stage1	36,299 gallons	50,000 lbs	520	600	N55E
	Stage 2	39,701	62,500	600	400	N50E
	Stage 3	30,974	45,000	475	400	N45E
	Stage 4	35,140	45,500	250	350	N40E

Table 1 – Summary of Treatment Parameters and Fracture Geometry From 12 Mapped Stages

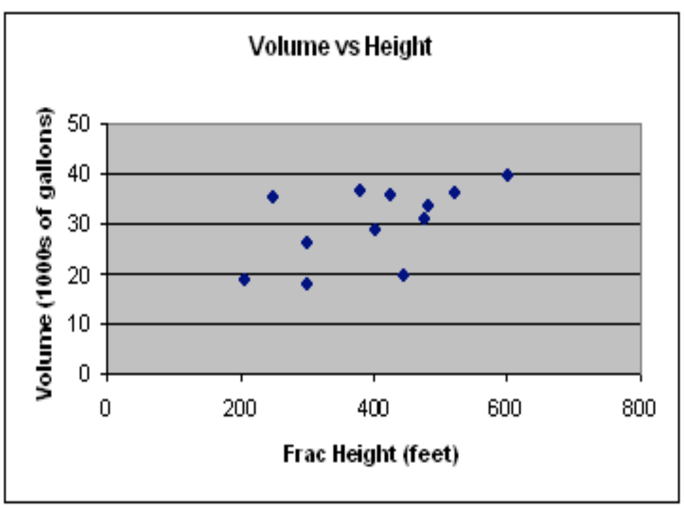

Figure 4 – Fracture Height vs Treatment Volume

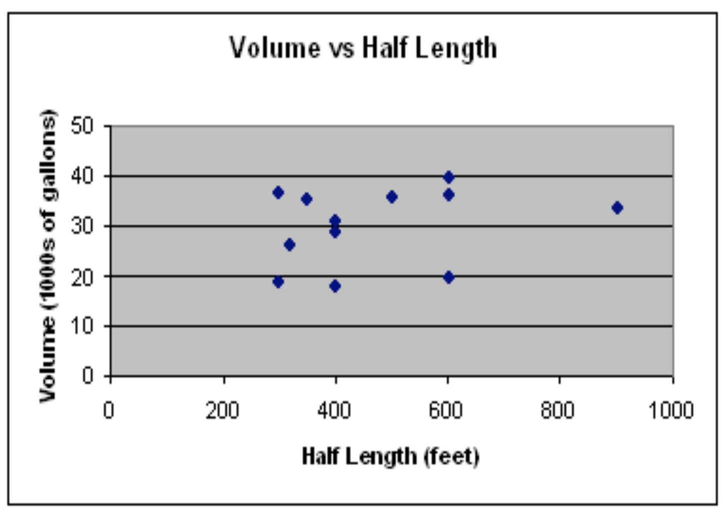

Figure 5 – Fracture Half length vs Treatment Volume

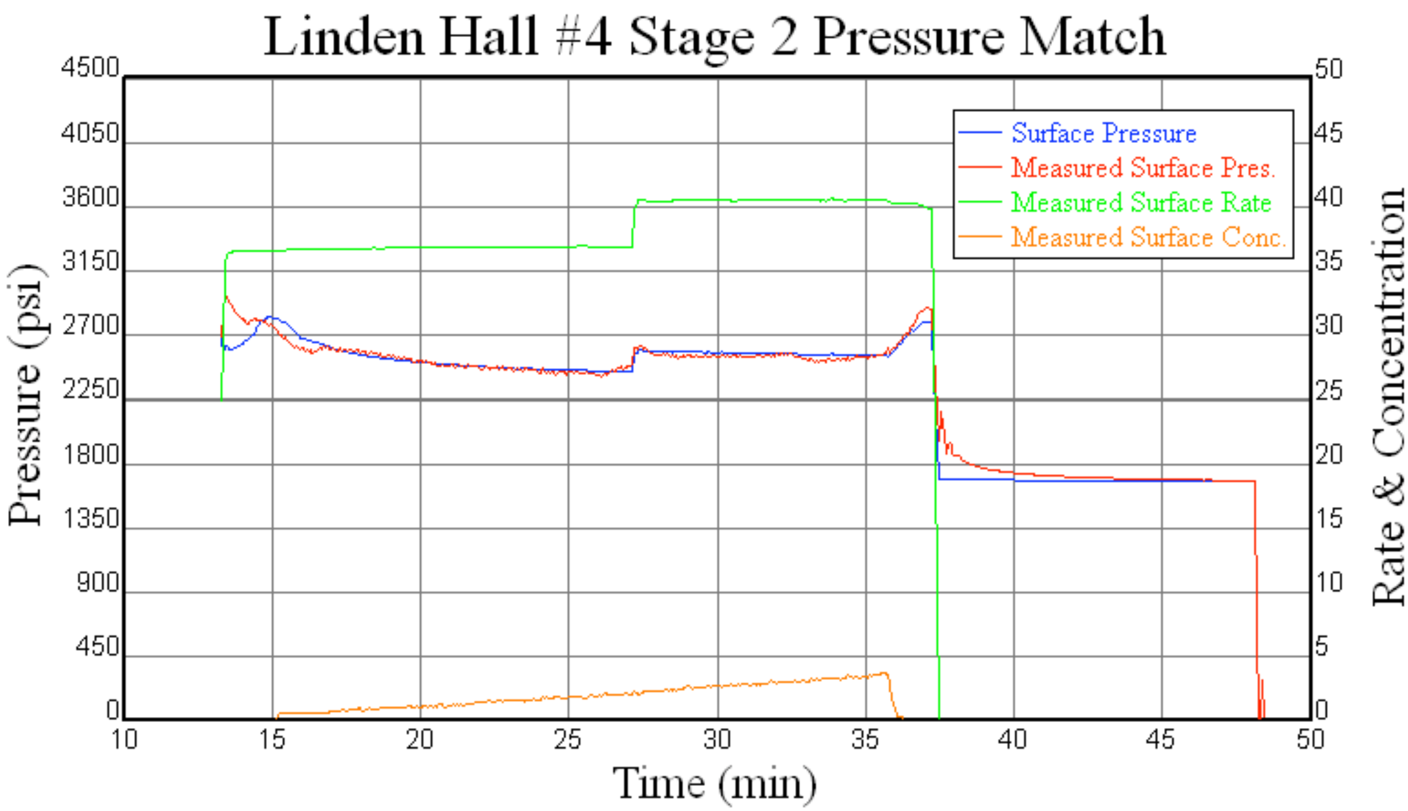

Figure 6 – Treatment Pressure History Match of Linden Hall #4, Stage #2

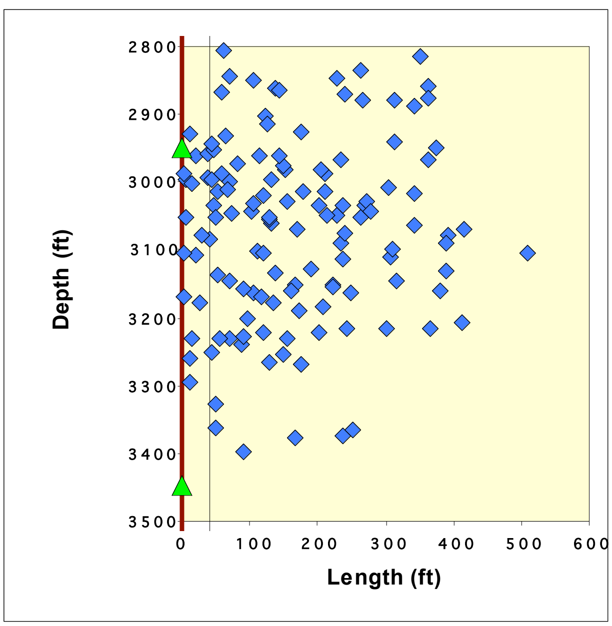

Figure 7 – Plot of Microseismic Events Mapped During Treatment of Linden Hall #4, Stage 2

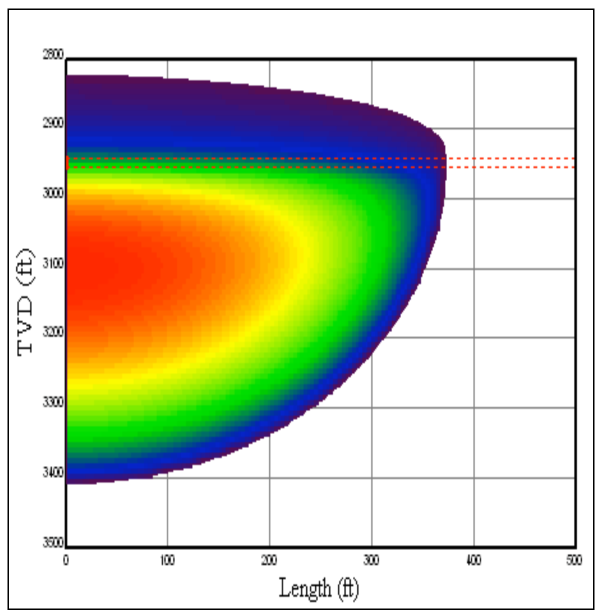

Figure 8 – Fracture Profile Generated From Fracture Model Treatment Pressure Matching

Appendices

- Appendix A – SPE Paper Number 97993
  Geology and Geometry: A Review of Factors Affecting the Effectiveness of Hydraulic Fractures

- Appendix B – SPE Paper Number 97994
  Application of Microseismic Imaging Technology in Appalachian Basin Upper Devonian Stimulation

SPE Paper Number 97993

Geology and Geometry: A Review of Factors Affecting the Effectiveness of Hydraulic Fractures

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Abstract

Thousands of wells are hydraulically fractured in the Appalachian Basin each year with little clear understanding of what the resulting fracture actually looks like. A number of variables exist in the subsurface including natural fractures, permeability variations, in-situ stresses, faults, etc. that can influence the ultimate dimensions and orientation of the created fracture. It is necessary that the stimulation design team understand the impacts that these features can have on the path a hydraulic fracture takes in the subsurface. The created fracture and its conductivity ultimately dictate a well's productivity and drainage area.

This paper will outline the basics of how in-situ stresses affect the orientation of propagating hydraulic fractures and how some geological characteristics can impact the process. Some discussion will be presented on the current technologies being used to understand fracture geometry. These include microseismic imaging and tiltmeter surveys.

Introduction

The vast majority of Appalachian Basin reservoirs require some type of stimulation to be economically viable. Many thousands of wells have been drilled and completed utilizing a variety of stimulation techniques. Both the reservoir and the created fracture are, by their nature, difficult to see and assess with any real certainty. It is therefore necessary to make assumptions about how the geology of the reservoir will respond to the style of stimulation in order to optimize the recovery of hydrocarbons. Over the years some principal assumptions have been accepted that influence the hydraulic fracture design for the majority of treatments. Some of these assumptions were controversial at first but have gained

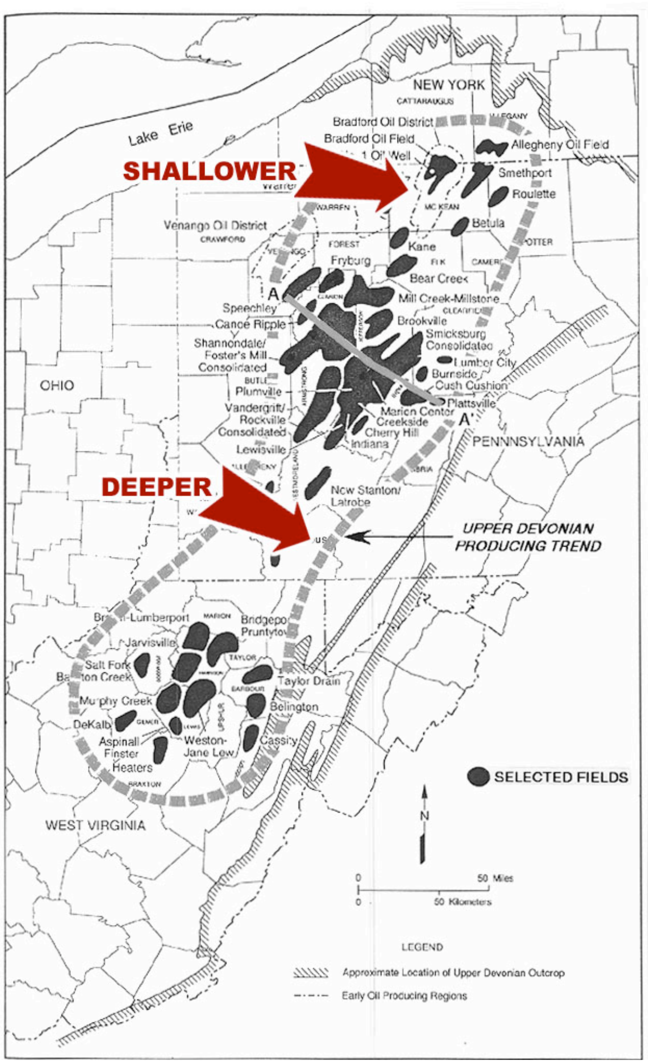

Figure 1 – Appalachian Basin Bradford Group Play

general acceptance over time. Other design factors are the result of "local" conclusions based on the results of treatments that have been refined through years of modification.

Traditional methods of predicting fracture growth include computer modeling, treatment pressure analysis, radioactive tracers, and well testing. Comparing the inferred geometry for a series of wells with the direct far-field fracture mapping results can help to determine if the inferred techniques have merit in the determination of true fracture geometry[1]. Microseismic imaging, a technique that images the created fracture by monitoring seismic or micro-earthquake "events" during the treatment from an array of sensors in an offset wellbore, has gained wide acceptance as a reliable method of determining created fracture geometry over the last 5 years. The microseismic images can also be utilized to calibrate other simpler and lower cost techniques if they prove applicable.

These measured created fracture geometry results need to then be related to production from the stimulated intervals to determine the fractures effectiveness. Where the results in production improvement are obvious and seem to apply for a formation over a large area, the stimulation style will usually be accepted and applied over a large region rather quickly. This can be seen in the shallow reservoirs of the Bradford group where operators are steadily increasing the number of fracture stages which directly correlates to increased production.

However there are few documented cases of production results being rigorously demonstrated to correspond to certain stimulation treatment designs for deeper horizons. Fontaine (SPE 78701) found a good correlation for a larger group of deeper wells in the Cramerven field in Northwestern Pennsylvania. He studied a large data set of wells in one field that had been completed by two operators with different stimulation schemes. In this case the reservoir, the Medina-Clinton group, is generally treated in one or two stages and the question of how many stages to use was not critical. He did discover that in the case of this field the total size of the treatment volume showed a direct correlation with ultimate recovery.

The highly competitive nature of regional leasing and the difficulty in obtaining good treatment data and production information makes correlating job type and profits a daunting task. A good first step is to better understand the created fracture geometry for a particular fracturing style in a given reservoir.

After a review of some of the basics of fracture growth and the techniques that are used to infer their geometry, a comparison of fracturing styles for a similar reservoir, the Bradford group, at different depths will be discussed. (Figure 1)

Basic Fracture Growth Concepts

It is generally accepted that hydraulic fractures propagate perpendicular to the least principal stress. It follows that in shallower environments where the least principal stress is vertical that a fracture will grow horizontally. At some depth where the increase in overburden causes the least principal stress to be horizontal the predominant fracture growth geometry will be vertical. (Figure 2) It follows that the azimuth of a vertical hydraulic fracture will respond to stress and propagate in the direction of least resistance (in the direction of the maximum horizontal stress where the fracture opens against the minimum horizontal stress). Variations in stresses between different lithologies in vertical sequences of rocks can cause fracture growth in a contained manner and generate length or allow it to grow vertically upwards or downwards. Compounding the difficulties in attempting to predict how a fracture will grow are the many other features that can be present such as faults, natural fractures, bed laminations, and other characteristics of a reservoir that would be difficult to know or predict from the surface.

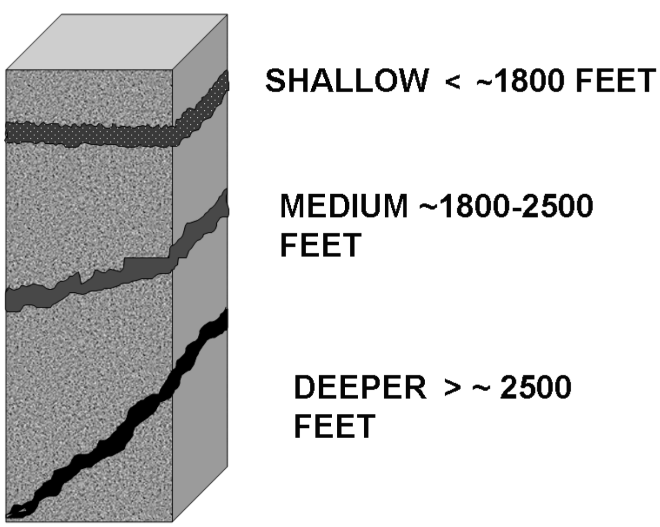

Figure 2 - Generalized inclination of fractures with depth

Some Methods of Inferring Fracture Geometry

It would be helpful for the design team if there were some easy way to determine the actual geometry of the created fracture. Unfortunately until relatively recently there was not much reliable data about what the created fracture actually looked like. Direct far-field fracture monitoring techniques (passive microseismic and downhole tilt) hold the promise to definitively measure the created fracture. While commercial, these are relatively expensive and require an optimum situation where the tools to image the fracture are placed in an offset wellbore at a distance close enough to detect the signal from the created fracture. It is anticipated that refinements of these techniques will allow imaging from the treatment wellbore itself in the near future at a lower cost. Many different techniques have been developed and refined in hopes of better understanding fracture geometry without having to dig down and see it with our eyes. A few of the most common techniques will be briefly described below.

Pressure Methods
The rock mechanics academic community has worked diligently to find ways to determine how the fracture geometry develops during a fracture treatment by monitoring and analyzing the pressure of the injected fluids. The most common interpretation of this type would be the Nolte-Smith plot where inferences are made about fracture geometry from the changes in bottom hole pressures during the job. Ideally the pressure must be measured as close to the actual fracture as possible. Using surface pressure alone can give erroneous data as it is necessary to account for the many factors that can make the pressure measured at the surface differ from that pressure at the fracture face.

These factors include:
1. Friction pressure will vary in relation to a number of variables such as fluid rate, tubular size and roughness. These pressure effects must be subtracted from the surface pressure.
2. Hydrostatic pressures of the fluid column will change during the treatment as proppants are added and fluid densities change. As proppants are added and the density increases, the pressure measured at the surface will decrease. If a job utilizes nitrogen or foams this will decrease density resulting in higher pressures at the surface.
3. Perforation friction pressure is a function of perforation size and the number of holes that are accepting fluid. The density of the treatment fluid entering the perforations must be known.
4. Near well bore pressure effects, commonly referred to as Tortuosity, can be the result of the fracture changing the direction in which it is propagating. This might occur if the perforation is not aligned with the least principal stress and the fluid must pass through the higher stress area near the well bore. The fracture will alter its direction over some distance to align with the lower stress environment. This higher stress portion of the fracture near the well bore will be narrower and will impart a higher friction pressure. This restriction will reflect itself at the surface as another increase in imposed pressure. This additional measured surface pressure doesn't reflect the actual pressure necessary to continue propagating the fracture.

A Nolte-Smith plot is one of the most common methods of pressure analysis and would infer the type of fracture growth from an analysis of treating pressure in a form represented in the diagram Figure 3. In this type of analysis a positive slope of pressure is interpreted to demonstrate hydraulic fracture growth in a confined and extending manner (segment labeled I). The regimes labeled III-a and b represent an impending "screenout", or termination of the job due to excessive pressure. This can be the result of the formation permeability being too high allowing excessive frac fluid leakoff and the consequent proppant drag. This pressure signature could also be the result of insufficient fracture width causing excessive friction drag on the proppant. The segment labeled IV could indicate uncontained fracture growth vertically, which might have the fracture growing outside the boundaries of the stimulation target zone.

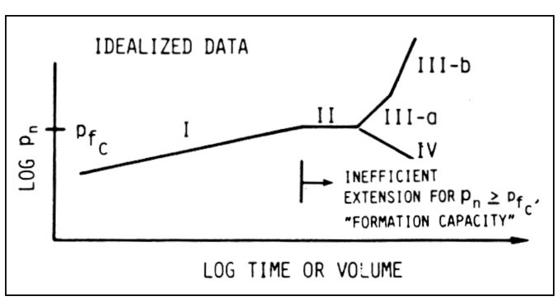

Figure 3 - Nolte-Smith characterization of fracture growth related to pressure analysis

Radioactive Tracer Surveys

Radioactive tracers can be added to the sand stages of a stimulation treatment and will be transported and placed with proppant pack. A logging tool is run over the interval after the job to note where the tracer-laden proppant is placed. The largest limitation of this technique is that the logging tool has a relatively shallow depth of investigation and will only image the fracture very near, within inches, and directly adjacent to the wellbore. It is impossible to image the fracture in the far-field.

Computer Fracture Models

Computer fracture models have been developed that attempt to predict how a fracture will grow in the subsurface. They require a variety of inputs that will enable the model to calculate fracture geometry. The variables include characteristics of the rocks including:

1. Rock stresses
2. Fracture fluid leakoff (Permeability, natural fractures)
3. Young's modulus
4. Poisson's ratio

Computer models can reflect a wide variety of geometries depending on what inputs are entered. They are particularly sensitive to the stresses that are assumed, but not often actually measured, in the subsurface. For this reason a computer model of a particular job design can give a false sense of security about the effectiveness of a fracture stimulation design. For a given geology it is simple to see the error that could be made if one were to assume that a particular job was contained within the reservoir rather than having fracture growth into bounding layers. Certainly for this case, we wish that the job stay contained, but this may not be the case, resulting in a less than optimal treatment where the sand pack is distributed below the pay zone and the hydraulic fracture has not penetrated deeply. Equally concerning is the inverse situation where we desire to fracture multiple sands with a single treatment; if the treatment is more contained than designed for, reserves will not be recovered. Understanding and predicting how hydraulic fractures grow is critical if the goal is to economically maximize the field recovery.

Methods of Determining Fracture Geometry

Microseismic Imaging Passive microseismic imaging of hydraulic fracture treatments, while widely utilized in other parts of North America has not seen general application in the Appalachian Basin. The microseismic mapping process detects and plots in three dimensional space microseisms which are micro-earthquakes induced by the changes in stress and pressure associated with hydraulic fracturing.[2,3,4] These micro-earthquakes are slippages that occur along pre-existing planes of weakness (e.g., natural fractures) which emit seismic energy that can be detected at nearby seismic receivers. If an array of tri-axial receivers is situated at depth near the hydraulic fracture, compressional (primary or p) and shear (secondary or s) waves can be detected and locations of the events can be calculated. These microseisms are extremely small and sensitive receiver systems are required to obtain accurate results.[5] The location of any individual microseism is deduced from arrival times at the receiver of the p and s waves (providing distance and elevation data) and from particle motion of the p-wave (providing azimuth from the receiver array to the event). In order to use the particle motion information, it is also necessary to orient the receivers which is typically performed by monitoring perforating, string shots, or other seismic sources in the treatment well or some other nearby well. Figure 4 Illustrates the Microseiemic mapping principles.

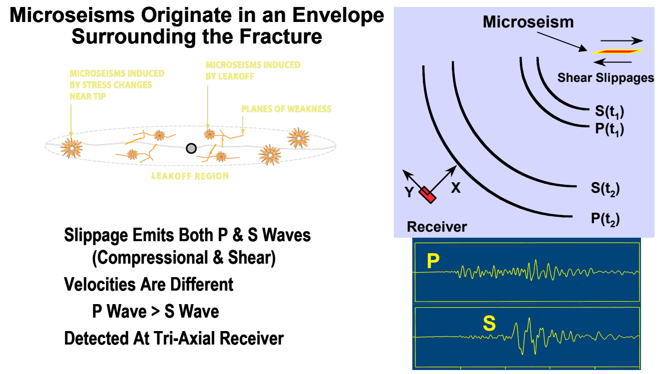

Figure 4- Microseismic Mapping Principle

This microseismic data can be assembled to portray the geometry of the fracture in a format that is very useful to the design team. It can reveal many facets of the fracture including its azimuth, height and symmetry. Of particular importance is its ability to define the complex nature of fracture growth as it intersects natural fractures, differing stress zones, etc. in the subsurface. Often it has been discovered that multiple fractures are being created where it was thought single fractures existed. This has been proven to be invaluable in helping to maximize the production rates and total recovery in a variety of fields including the Barnett Shale[6,7].

Tiltmeter Fracture Mapping

The principle of tiltmeter fracture mapping is simply to infer fracture geometry by measuring the fracture-induced rock deformation. The induced deformation field radiates in all directions and can be measured either downhole with wireline-conveyed tiltmeter arrays or with a surface array of tiltmeters. Surface tiltmeters measure the fracture direction, dip and depth to fracture center, whereas downhole tiltmeters measure the geometry of the hydraulic fracture. Figure 5 shows a schematic diagram of the induced deformation field from a vertical fracture (during injection) as seen both downhole and at the surface. The deformation field of a purely vertical fracture measured by surface tiltmeters is a trough that runs along the fracture direction with “bulges” on either side. The symmetry of the “bulges” on both sides of the trough indicates fracture dip. The deformation of a purely horizontal fracture is a radial bulge with the highest deflection centered roughly at the wellhead, and no associated troughs. Details of surface and downhole tiltmeter mapping technology are well documented in the literature[8-11].

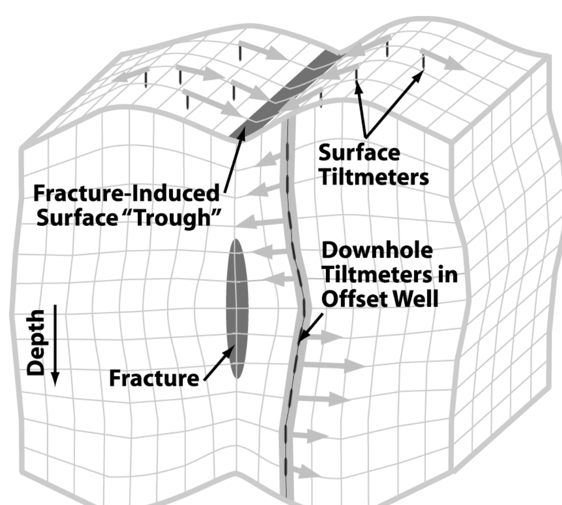

Figure 5- Deformation patterns measured by Tiltmeters

The Role Geology Plays in Hydraulic Fracture Design

Reservoir Description for Upper Devonian Bradford Sands

The Upper Devonian sands that are the target in the Linden Hall prospect (Fayette County, PA) can be compared with similar updip shallower Upper Devonian sands in North Western Pennsylvania (McKean Co.). This allows us to see factors that have to be defined to design a stimulation treatment.

In the case of the shallower Upper Devonian sand targets in the Bradford area of Northwestern Pennsylvania the stimulation treatments have evolved in a stepwise manner over the years to maximize production. These sands are on the order of tens of feet in thickness and have poor vertical permeability as a result of very thin but continuous shale breaks and many micro-laminations of heavy minerals.

The core photos (Figure 6, 7) show some of these very thin low permeability layers. There are many heavy mineral layers that exhibit themselves as the many dark horizontal lines that cross the cores. There are also many slightly thicker (on the order of 1 to 2 millimeters) horizontal shale layers that can be seen cutting the core. These layers have extremely low permeability and are effective "gaskets" between the many micro reservoirs stacked vertically in the reservoir. In a typical electric gamma ray log run at a normal scale these features would not be evident at all. The average tool and analysis software would "average" the contribution of these thin features and represent a slightly shalier sequence on the log.

Figure 6 - Thin Shale Bed in Core

Figure 7 - Thin Lamination in Core

Figure 8 - Upper Devonian Sand outcrop

Bradford play reservoirs are typically very fine to fine grained sandstones and siltstones deposited in a variety of environments of the Catskill delta complex. (The Atlas of Major Appalachian Gas Plays, p. 71) The permeability ranges greatly throughout the sequence from 0.2 to 760 md with porosity ranging from 9.8% to greater than 18%(Ingham and others, 1956; Overbey and Evans, 1965).

Meyers (SPE 78700) pointed out that a Bureau of Mines investigation of rock samples from the Appalachian Basin showed that even in higher permeability samples the vertical permeability was at least 10% less, suggesting that in lower quality rocks, the disparity might be higher. Certainly the permeability in even the thinnest shale interbeds is a fraction of the horizontal permeability.

On a larger scale, an outcrop of Upper Devonian rocks demonstrates the layered nature of the many "sub" reservoirs that can exist. While the micro-laminations divide the units into segments, the whole group can be divided by larger discrete shale beds. It is also interesting to note that the whole section can be penetrated by inclined or vertical natural fractures further complicating the fracture design process. (Figure 8)

Comparing Stimulations and Results for Similar Bradford Reservoirs at Different Depths

There is a typical stimulation technique used in the shallower (less than 2000 feet in depth) Upper Devonian reservoirs in the Bradford, Pennsylvania region. It is generally referred to as “open hole” or “packer and plugback” fracturing. In this type of stimulation the zone to be stimulated is uncased and “open”. Generally there are multiple intervals that are stimulated and they are “notched” with a downhole sandblasting technique. A “notch tool” with small carbide nozzles is attached to the bottom of tubing string and rotated as air and sand etch a “ring” or “notch” in the formation sand. The created “notch” is usually on the order of an inch or two in depth. This horizontal “notch” works much as a perforation in a cased well as the point of initiation for the treatment slurry. The notches are usually treated separately and progressively down the well a stage at a time. The stages are isolated using a tension set openhole packer and a pea gravel filler referred to as “plugback”. After notching, the well is filled with plugback to a point above the uppermost notch. The packer is reverse circulated down below the notch to be treated then pulled above the notch and set. This process allows the discrete treating of many zones. These multiple fractures usually do not communicate during pumping indicating that the fracture geometry is horizontal or highly inclined.

Although in use for years, this technique continues to be refined as additional production results are correlated to the number of stages. At one time there was debate as to whether the created fracture in this situation was actually horizontal. Many studies have confirmed that fractures will grow horizontally in shallow environments. One confirmation is that multiple stages are completed with this technique and it is rare that communication around the packer is observed.

How Does Geology Relate to the Stimulation Design for Shallower Targets?

In a shallower depth regime the geometry of the created hydraulic fracture will be predominantly horizontal. The nature of the Upper Devonian rocks is such that the barriers to vertical permeability, both micro-laminations and shale layering, must be accounted for in any stimulation design. Even in thin sand beds a large portion of the reservoir might not be in communication with the hydraulic fracture due to these features (Figure 9). In this situation it is necessary to maximize the number of stages per sand body. In the past, stimulation treatments attempted to notch and treat the “sweet spot” in a particular sand body. Correlation of production and number of stages has revealed that the controlling factor in maximizing a well’s potential is the total number of stages.

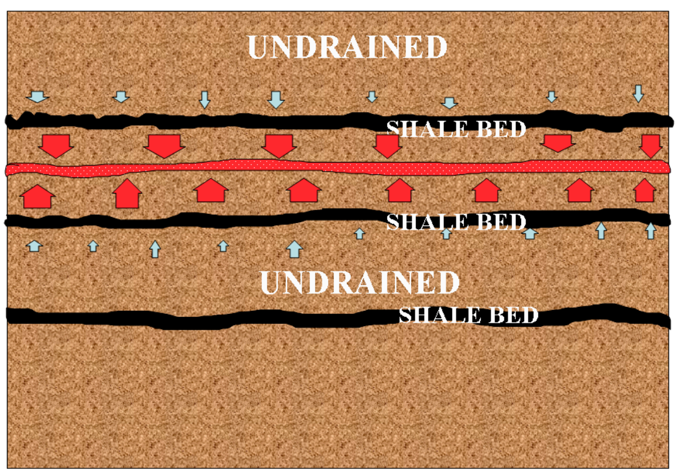

Figure 9 - Shallow horizontal hydraulic fracture confined in higher perm sand body

A good study of this theory was done by Belden and Blake Corporation and presented by Leo Schrider at the PTTC’s Upper Devonian Workshop on “Recent Developments in Upper Devonian Sandstone Plays” held in Washington, PA on May 26th 2005. Schrider wanted to quantify if economical production improvements could be obtained by fracturing additional zones in existing Upper Devonian Sandstone wells.

The intervals to be investigated were typical Upper Devonian Sandstones of the Tiona Group and Bradford Group in McKean County, PA. Twenty eight wells that had been previously fraced were stimulated in zones that had not been completed when the earlier treatments were done. They targeted zones that appeared gassy and might have lower porosity than earlier thought to be productive. They added from 4 to 11 additional stages per well. 27 of the 28 wells experienced an economic production increase. The first three months production per well was increased from 12 to 80 mcf/day. The average production increase was 35 mcf/day. Enhancement EUR's averaged 13.5 mmcf natural gas plus a small amount of oil. Of note was the comment that "Geologists and engineers teamed up to identify and frac additional zones in wells that were nearly depleted". The average well life was extended 5+ years and most paid out in less than 12 months. They did not notice a correlation of number of stages with production but did attempt to maximize the number of stages per zone. This did not allow a comparison of varying the number of stages in like sands over a large data set to evaluate the effect of vertical permeability barriers.

Stimulation Design for Upper Devonian Sandstones in Deeper Reservoirs

The most common stimulation style for the deeper reservoirs of the Upper Devonian is referred to as "ball and baffle". The well is cased, cemented and perforated using jet perforators. The unique component is the use of multiple, sequentially smaller, restrictions called baffles, placed in the casing as it is being run. This technique allows for the isolation of zones during the treatment by dropping progressively larger "frac balls" which land on the strategically placed baffles.

In shallower Devonian Sand reservoirs it is necessary to complete every discrete reservoir with a stage to maximize recovery. In deeper settings the design team needs to determine the geometry of the fracture and relate it to the geology of the reservoir rocks. In this case it is vital to determine the height of the fracture. This is necessary for several reasons. First the fracture could be growing vertically through several target zones from a single stage. In this case it is necessary to decide if one stage can serve to stimulate several zones in a more cost effective manner than pumping multiple stages. A vertical fracture can penetrate the many vertical permeability barriers and communicate with multiple discrete reservoirs. (Figure 10) For this reason it is important that the design team has a clear understanding of what the geometry of each stage will connect.

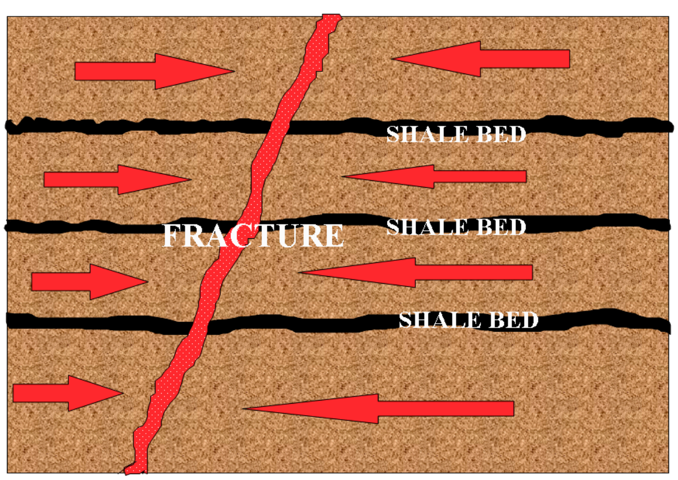

Figure 10 - Hydraulic fracture connecting sand bodies through shale barriers

In order to maximize production, the hydraulic fracture not only has to penetrate a zone but hopefully deliver proppant that will serve to make the created fracture conductive. If the fracture grows below the zone of interest the proppant after settling might not provide a sufficiently conductive pathway to the wellbore limiting the well's production.

Recent Developments in Imaging Deeper Upper Devonian Hydraulic Fractures

The Microseismic Fracture Imaging of the Great Lakes Energy Partners Linden Hall prospect in the Hunker Field has added a huge piece to the puzzle of how hydraulic fractures grow in some reservoirs of the Appalachian Basin. This advance was the result of a Stripper Well Consortium funded project involving Universal Well Services, Inc., Great Lakes Energy Partners and Pinnacle Technologies. Fontaine (SPE-97994) has discussed the early results in his paper.

The microseismic image of the created fractures in the Linden Hall project allow us to compare and calibrate some of the simpler techniques described earlier in the paper. It will take a more in depth analysis to properly analyze the results but preliminary comparisons point to some correlations.

1. Uncalibrated computer models (Figure 11) gave a more contained fracture aspect ratio than was actually created (Figure 13)
2. Calibrated computer models more closely resemble the created geometry as illustrated by microseismic mapping (Figure 13).
3. Vertical penetration of fractures into sand bodies, both above and below, was greater than previously thought
4. Initial pressure analysis of the treatment showed that a close understanding of all the contributing variables is necessary to give the technique any validity (Figure 12)
5. Tracer studies would not have predicted actual fracture geometry in the far field as fracture growth would have been to far away for the receiver to detect the radioactive material

Continuing Evaluation of Developments in Hydraulic Fracturing of the Devonian Sands

The imaging of Upper Devonian Sand horizons in the Linden Hall project points out the need to evaluate if the overlap of fractures from discretely fractured zones has a negative or positive impact on well performance. It will be necessary to determine if the hydraulic fractures actually intersect or exist in parallel but unconnected geometries. The implications of either scenario are not trivial as they pose many questions for the design team. Some of the possible implications are:

1. The fractures do communicate with each other and it is not necessary to perform as many stages to drain sand bodies that can be stimulated in one stage.
2. The fractures do not communicate but are parallel but non-connected. In this case it is unlikely that this is an efficient and cost effective method of draining the adjacent reservoirs. One stage might be sufficient to effectively drain the targets in this case.
3. Sand placement might be less than optimal based on design goals for fracture conductivity
4. The fractures do communicate but have a positive impact on production as they serve to better distribute the sand pack and assure fracture conductivity for each zone in a suitable range.
5. Stress shadowing, a term used to describe the effect an existing fracture can impose on a nearby propagating fracture, might have a positive influence on containing the propagating hydraulic fracture.
6. Stress shadowing may also be responsible for causing asymmetrical fracture growth.

Production testing will be performed on the Linden Hall project wells to determine how the production from each stage can be understood. Analysis of this data will give us a better idea if some of the above scenarios have any merit.

Summary and Recommendations for Maximizing Hydraulic Fracture Effectiveness

The interaction of the hydraulic fracture with the geology present in the target is the fundamental concern of the design team. The engineering and geological participants of the team must spend some time discovering the critical aspects of the controlling factors in effective reservoir drainage. All members of the team should strive to define the factors that contribute to the design for each particular discipline and horizon.

Acknowledgements

The authors would like to thank the Stripper Well Consortium for their participation in this project

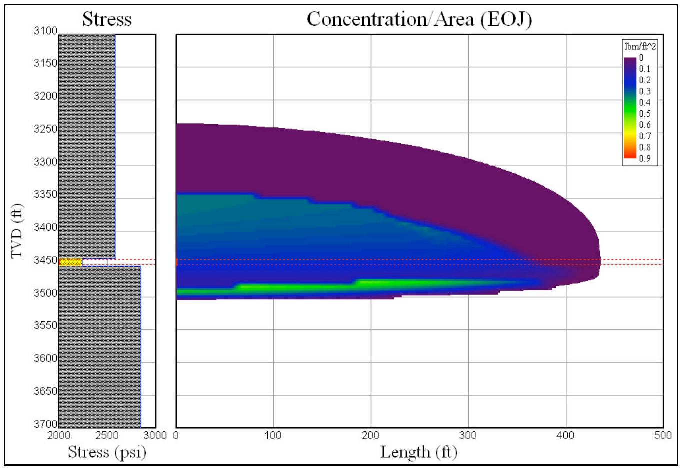

Figure 11 – Uncalibrated computer model

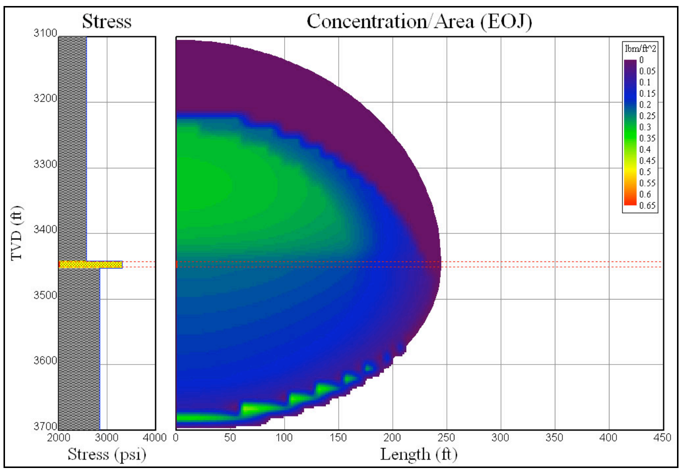

Figure 12 – Calibrated computer model

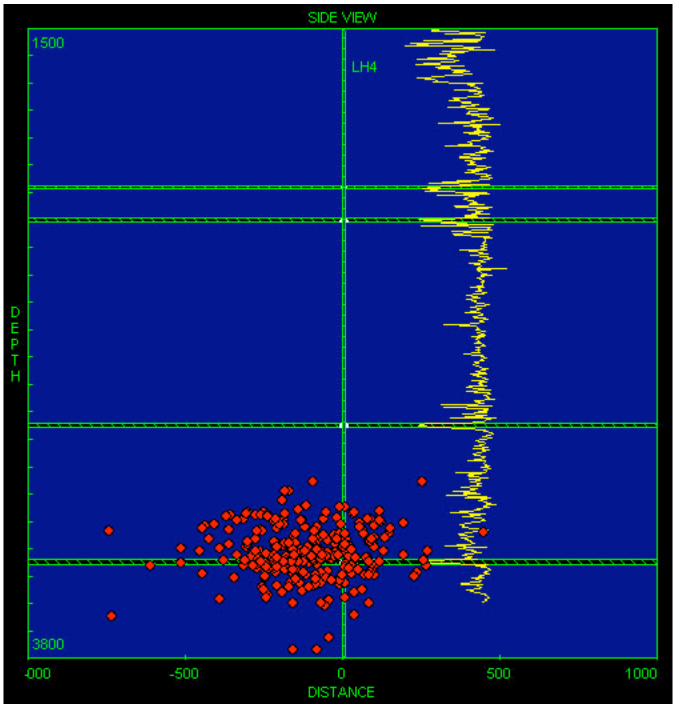

Figure 13 - Microsiesmic Events

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SPE 97994

Application Of Microseismic Imaging Technology in Appalachian Basin Upper Devonian Stimulation

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Abstract

Microseismic imaging technology can help in providing the answers to many previously unknown questions involving the process and results of hydraulically fracturing the sandstones in the Upper Devonian wells of the Appalachian Basin. Uncertainties surrounding fracture orientation, fracture length, fracture height, the effect of treatment size, and identification of potential fracture complexities can be reduced. Developing an understanding of fracture geometry is vital and can lead to improvements in reservoir management and development.

Every year thousands of wells are drilled and completed in the Upper Devonian sands throughout the Appalachian Basin. Nearly all of these wells are fracture stimulated in some manner. The tools available to the completion engineer in designing these treatments are limited and uncertainties regarding their efficiency and optimization often exist. Process improvement can be limited or delayed by the lag time involved in determining stimulation effectiveness based upon production results. Even then inferences must be made concerning fracture geometries based upon well testing or fracture modeling. The use of microseismic fracture imaging allows real time or near real time decisions to be made.

This paper will present a case history of the implementation and utilization of microseismic fracture imaging conducted in three multi-stage stimulation treatments in Devonian Sand tight gas wells in Pennsylvania. The created fracture geometries and their implications for future treatment design, fracture model calibration, and reservoir management will be explored.

Introduction

The Upper Devonian sandstones of the Appalachian Basin are an important and well documented natural gas resource. Extensively drilled and exploited since Drake's original discovery well in 1859, these reservoirs include but are not limited to the Venango Group sandstones, the Bradford Group sandstones, and the Elk Group. Tens of thousands of wells produce from these formations throughout the Appalachian Basin, primarily in Pennsylvania and West Virginia. The majority of these producing zones are tight gas sands and as such require enhancement primarily through the use of hydraulic fracturing. The type of fracture stimulation utilized varies widely, from conventional gelled water fracs to nitrogen foam fracs, to crosslinked gel fracs. Stimulation selection criteria is commonly based upon what has been deemed most successful in the past in an area by any given operator. This success is usually inferred through trial and error and based strictly upon production response and dictated by economics. Little or no concrete knowledge exists regarding the actual created and propped fracture geometries resulting from the fracturing process. These unknowns include fracture height, fracture length, and azimuth. To further complicate any attempt to determine these parameters via production testing is the fact that most wells are completed in multiple zones using the ball and baffle staging process.

While computer fracture modeling is frequently used as a tool in attempting to optimize fracture design, many assumptions must be made with regard to the rock mechanics which ultimately dictate fracture geometry. Accurate measurements of such important parameters as Poisson's Ratio, Young's Modulus, fracture toughness, formation stresses and most importantly stress variations between adjacent formations are all too seldom available for use as inputs in modeling. Most commonly, the fracture models are used to match pressures gathered from actual treatments and thereby back into a best guess at the geometry created by the treatment. Once a reasonable pressure match is created, the predicted geometries are commonly accepted at face value. While this may (or may not) result in a valid representation of the fracture, what is still lacking is any true knowledge of the fracture direction or azimuth. This component of geometry is vital to the optimization of reservoir development and ultimate recoveries.

Microseismic imaging of hydraulically created fractures can answer many of these uncertainties surrounding created fracture geometry. The created fracture dimensions can be observed, measured, and ultimately correlated with variables in the stimulations such as volumes, rates, and fluid selection. Previously unknown factors such as fracture asymmetries, preferential fracture growth in multiple zone completions, unforeseen fracture complexities such as natural fracturing, and the effects of multiple stage completions from the same wellbore can be observed. Ultimately, improvements in the fracturing process can be made based upon concrete data.

In this paper, the results of microseismic imaging of hydraulic fractures in Great Lakes Energy Partners' Hunker Field in southwestern Pennsylvania are presented. This project produced the first microseismic images of fracture treatments in the Upper Devonian Sands of the Appalachian Basin. The field is in Fayette County Pennsylvania and is a typical case of development drilling in the basin. Zones treated and imaged included the Fifth Sand, the Lower Bayard, the Speechley, and the First Bradford.

Microseismic Basics

While microseismic fracture mapping has been utilized for approximately 25 years to monitor hydraulic facture stimulations[1], it has only been over the last 5 years that this technology has been widely accepted and applied to typical oil and gas fields. Conservatively, over 1000 hydraulic fracture treatments have been mapped over the last 5 years, compared to less than 100 treatments mapped in prior years. The microseismic mapping process detects and plots in three dimensional space microseisms which are micro-earthquakes induced by the changes in stress and pressure associated with hydraulic fracturing.[2,3,4] These micro-earthquakes are slippages that occur along pre-existing planes of weakness (e.g., natural fractures) which emit seismic energy that can be detected at nearby seismic receivers. If an array of tri-axial receivers is situated at depth near the hydraulic fracture, compressional (primary or p) and shear (secondary or s) waves can be detected and the precise locations of these events can be calculated. These microseisms are extremely small and sensitive receiver systems are required to obtain accurate results.[5] The location of any individual microseism is deduced from arrival times at the receiver of the p and s waves (providing distance and elevation data) and from particle motion of the p-wave (providing azimuth from the receiver array to the event). In order to use the particle motion information, it is also necessary to orient the receivers which is typically performed by monitoring perforating, string shots, or other seismic sources in the treatment well or some other nearby well. Accurate location of the microseisms, and thus the fracture image, is strongly dependent on accurate information about the velocity structure. An illustration of the general concept is shown in Figure 3.

Figure 4 illustrates two typical wellbore configurations utilized in a microseismic mapping project. A vertical array of 5 to 12 geophones is run into the offsetting observation well. Each geophone contains three sondes which detect the p and s waves of the microseisms from differing vertical depths. This affords the ability to locate the event location in three-dimensional space. As shown, the array may be positioned either above or straddling the zone being stimulated. As the treatment is pumped, a map of the occurrence of seismic events is developed which results in a determination of fracture azimuth and fracture dimensions.

Treatment Description

The three wells that were imaged were all stimulated using standard Upper Devonian style treatments. This entails the use of frac balls and baffles to isolate the zone being treated. The deepest stage in a well is first perforated and treated. After pumping is completed, the well is flowed back until the next stage can be perforated. After perforating, a frac ball is pumped downhole until it seats in a baffle which has been run in the casing string between the two zones. This effectively seals off the lower zone that has been fraced and the upper zone is then isolated for treatment. This process is repeated until all zones in the well are completed. The Linden Hall #3 was fractured in five zones and the Linden Hall #1 and #4 were each fractured in four zones. The depths of the individual stages ranged from 2100 feet to 3450 feet. The zones treated included the Fifth Sand, the Lower Bayard, the Speechley, and the First Bradford.

All treatments pumped were composed of a slickwater base fluid system placing 20/40 mesh API Spec Ottawa sand as a proppant at concentrations ramped from ½ to 4 PPG. The Linden Hall #1 was treated and imaged first. A total of 103,600 pounds of proppant was placed in four stages in this well using 51,000 gallons of fluid. Subsequently, the Linden Hall #3 and #4 wells were treated with an average 148,000 gallons of fluid placing an average of 220,000 pounds of proppant per well. Stage volumes were increased in the treatments on the #3 and #4 in an effort to enhance the amount and quality of seismic data being generated. All stages in all three wells were pumped at a downhole rate of 35-40 BPM.

Results of Imaging
Figure 5 shows a map view presentation of the Linden Hall wells and plots the locations of the microseismic events recorded during the project. The microseismic array was installed in Linden Hall #2, labeled MS Tools. From this view, the preferred azimuths of fracture growth and the lengths of the fractures created can be seen. It is apparent from this plot that the preferred direction of fracture growth is in the southwest - northeast direction from the wellbore. On average all stages mapped grew along an azimuth of approximately N50E. Fracture azimuths for all stages mapped are listed in Table 1.

What cannot be seen in the mapview plot however, is the height component of the fracture geometry or the lengths of the fractures created during the separate frac stages. To see these features, a sideview plot such as Figure 6 can be generated. From this plot (from the Linden Hall #3 well) numerous items of interest can be picked out. Events corresponding to each frac stage can be viewed. The first stage, indicated by the blue markers, appears to have grown preferentially to the southwest. The second stage (red markers) seems to have been influenced by the first stage and grew preferentially to the northeast. This is presumably due to the effects of “stress shadowing,” an alteration of the stressfield due to placement of the first fracture. In other words, the fracture created during the first stage has increased the rock stress and has influenced the fracture placed in the second stage to propagate primarily in the opposite direction.

It is also readily apparent that the created fractures by no means stayed within the perforated sand layers. The sands are indicated by the layers drawn on the chart and correspond to the gamma ray curve. From this it can be seen that all stages experienced significant growth both upward and downward. It should be remembered however that microseismic imaging **does not** indicate proppant placement, it is a measurement of created fracture dimensions.

Within the cloud of colored markers indicating the fracture created during a particular stage, a discordant marker or two corresponding with those of the next stage appear, i.e. a red marker lies within the blue markers, several green within the reds, etc. This is due to the fact that while pumping the frac ball to the baffle between zones on a multiple stage well, the wellbore fluid is displaced into the previously completed, nonisolated stage until the fracball is seated, the new fracture is initiated and fluid is redirected into the new perforations. A similar situation was observed in the stimulation of the Linden Hall #4 in which a ballout was performed prior to the third fracture stage. As the perfballs were displaced, reactivation of the prior stage was observed. These microseismic events should not be interpreted as being a true component of fracture height.

It can be seen that the third stage exhibited both significant downward growth as well as preferential growth to the northeast. While the downward height growth is indisputable, caution must be used in assuming that the single wing to the northeast dominates this fracture. By referring to the mapview presented in Figure 5, it is seen that these events were advancing toward the receivers in the observation well. While corresponding events may have been occurring in the opposite direction, these may have been masked by the northeasterly advancing fracture noise. This interpretation differs from the first stage mapped in that during the first stage, the bulk of the events received were to the southwest or away from the observation well. Few events were recorded directly between the treatment well and the observation well thus indicating preferential growth to the southwest during that stage.

The fourth and fifth stages appear to significantly overlap each other and in fact events recorded during each of these stages were detected within the region which was stimulated during the third stage. Stimulation of all three of these upper zones may in fact be optimized by perforating and completing all three zones together in a single larger fracture stage rather than via traditional multiple stages. A similar overlapping of stages was also observed in each of the other two wells imaged.

A summary of all treatment volumes (fluid and proppant) and created fracture geometries (height, half-length, and azimuth) are listed in Table 1. Figures 7 and 8 illustrate the relationships between stage volumes and resulting fracture height and length. While there does not appear to be a 1:1 relationship between treatment volume and created geometry, in both cases it can be generally stated that with increasing volume comes both increasing fracture height and length. Further, it was observed that on average the fracture half- length is a mere 20% greater than the fracture height. This is a direct indication of the lack of stress contrast between layers and a resultant lack of containment.

Implications For Fracture Model Calibration

One of the most significant benefits resulting from directly measuring fracture geometry is the ability to calibrate and verify fracture computer modeling. Modeling is commonly used in predicting and evaluating the effects of design changes. While all models have standard default values for critical rock properties which ultimately determine fracture geometry, without calibration of these parameters, the veracity of the results generated by models can be questioned.

As an example of how fracture imaging can be used in calibrating a model, the second stage fraced in the Linden Hall #4 well has been pressure matched using commonly accepted methods. The actual treatment data was collected and imported into a commercially available fracturing simulator. The simulator was then used to model the created fracture using actual treating pressure, pump rates, and volumes. In order to create a pressure match, several of the default parameters were adjusted until a reasonable pressure match was obtained. The actual treatment data and the pressure match are shown in Figure 9.

Figure 10 shows the plot of microseismic events generated during the fracture treatment. It should be noted that several events appeared well below the main body of the fracture that actually occurred while the ball was being pumped which correspond to fluid reentering the perforations of the lower stage. Figure 11 is an illustration of the created fracture profile generated after calibration of the simulator. The created geometry is a good match to the data collected during the microseismic mapping. The created fracture height predicted by the model is 588 feet versus 600 feet plotted during mapping. The model predicts a half length of 373 feet while fracture mapping showed 400 feet of half-length.

One aspect of fracture geometry which cannot be addressed by modeling is the phenomenon of fracture asymmetry. Referring back to Figure 6, it can be clearly seen that asymmetrical fracture growth can and does occur. It should always be remembered and taken into consideration that reservoirs such as those being discussed here are rarely if ever homogeneous as is commonly assumed in modeling and engineering. For this reason, direct observation of fracture complexity and calibration of models using microseismic imaging can be an invaluable tool in stimulation optimization.

Conclusions

8) The dominant maximum horizontal stress direction (the direction in which the fracture grows) is roughly N50°E.
9) Fractures pumped in closely placed stages can and do overlap. Stimulation efficiency can potentially be enhanced by combining such zones and stimulating together in a single stage.
10) Fracture containment can be poor. Some zones can exhibit extreme upward and/or downward growth.
11) The effectiveness of fracture modeling can be enhanced through incorporation of microseismic data in model calibration.
12) Fracture asymmetry can occur due to a previously placed fracture altering the stressfield.
13) Procedures performed on a stage may affect previously stimulated nonisolated lower stages. (i.e. The pumping of frac balls or perfballs.)
14) Microseismic mapping can be successfully applied to monitor and optimize hydraulic fracture stimulations in the Devonian Sands.

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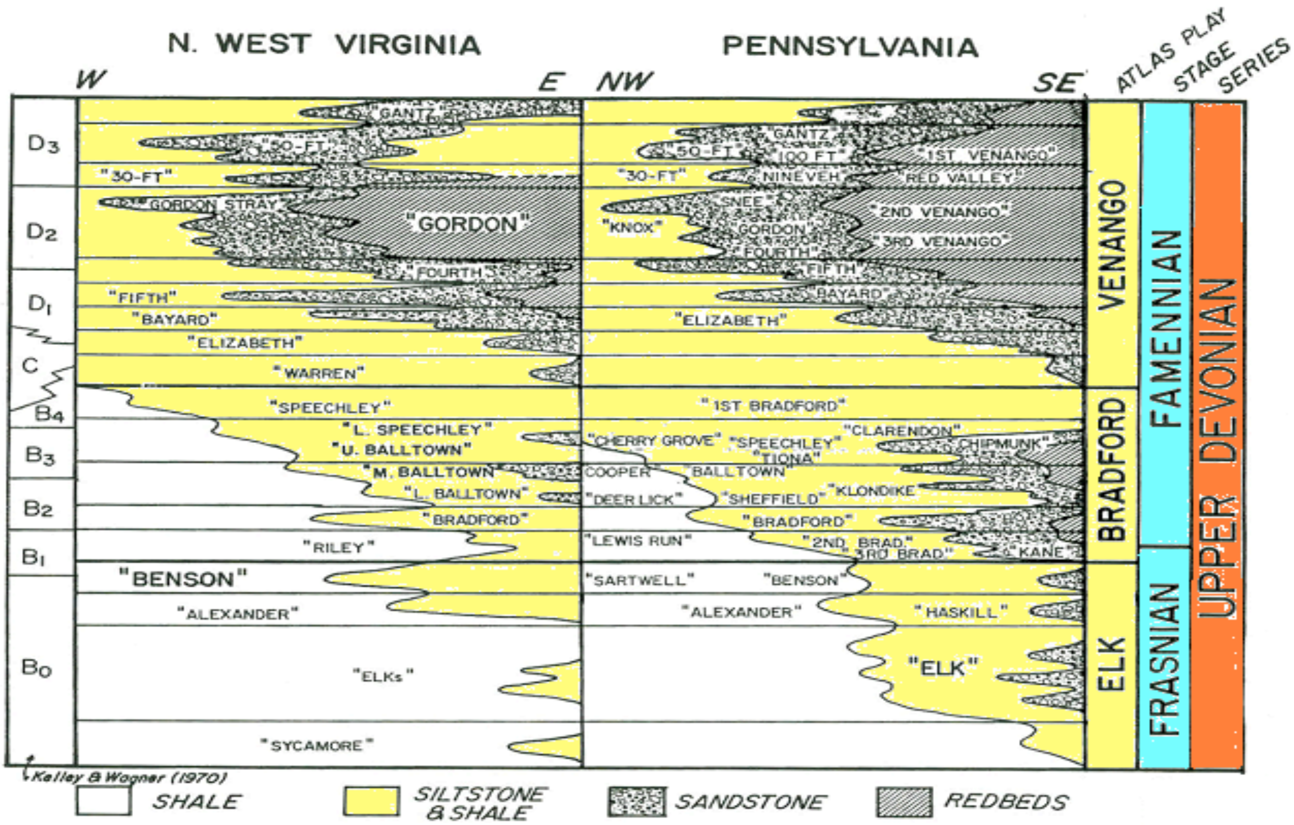

Figure 1 – Upper Devonian Stratigraphy (From Boswell, et al, 1996)

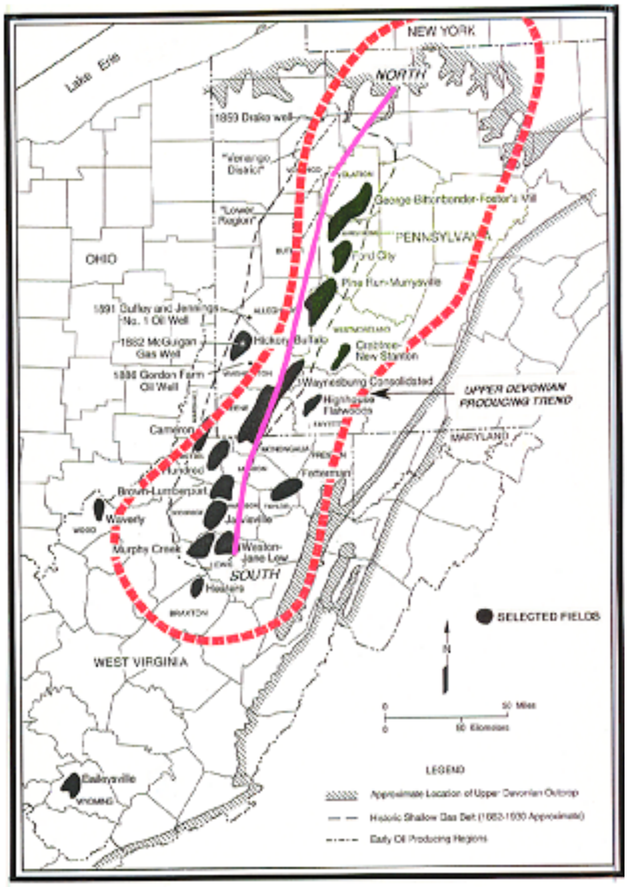

Figure 2 – Appalachian Basin Upper Devonian Trend

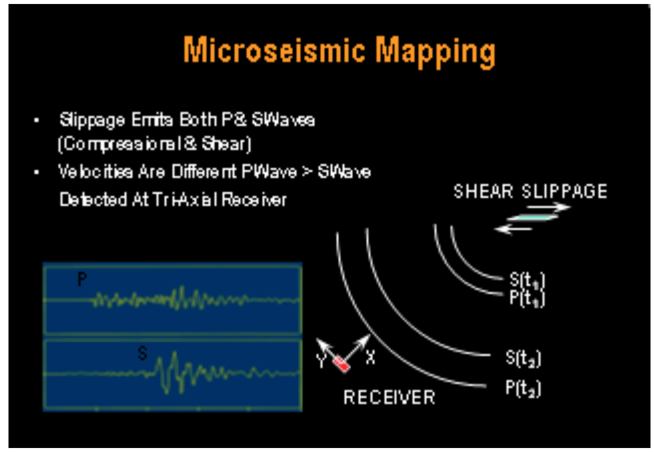

Figure 3 – Microseismic Event Components

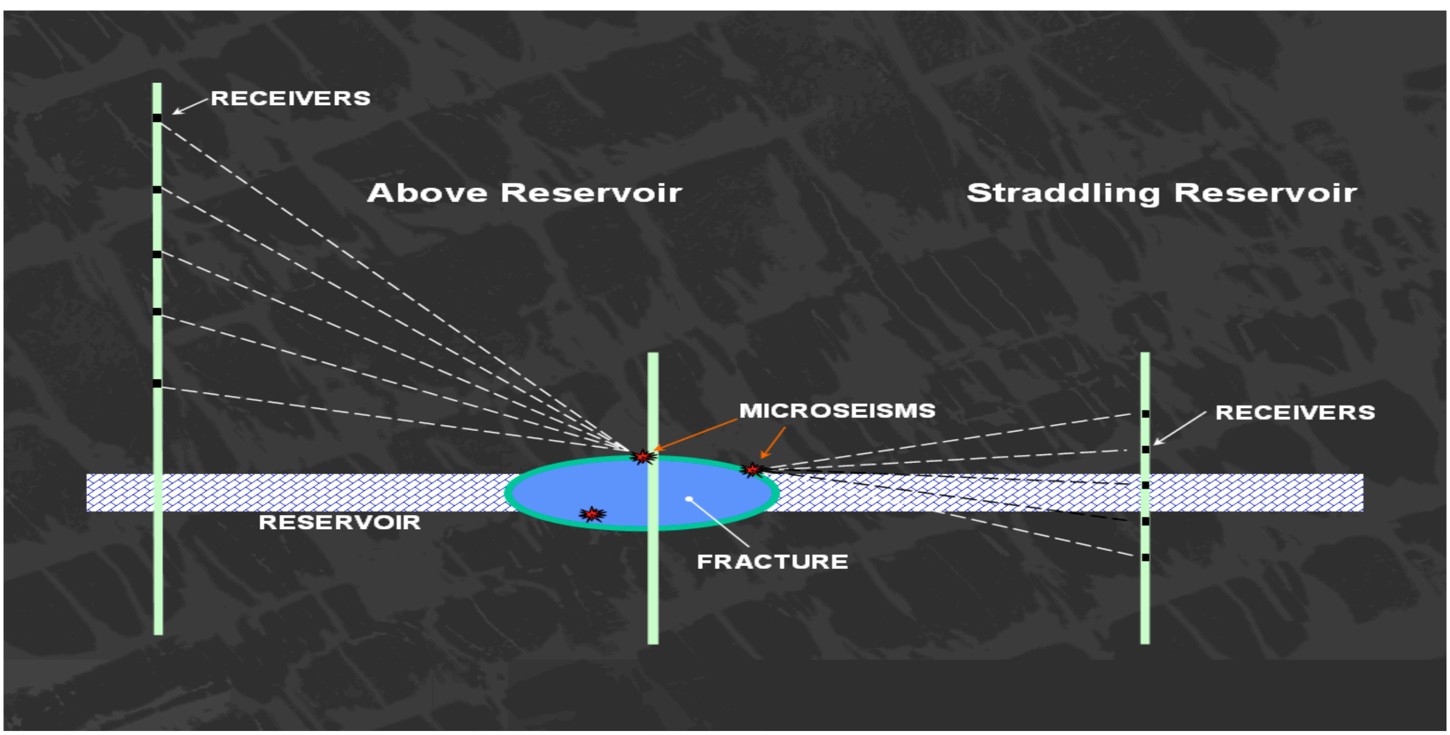

Figure 4 – Microseismic Event Location

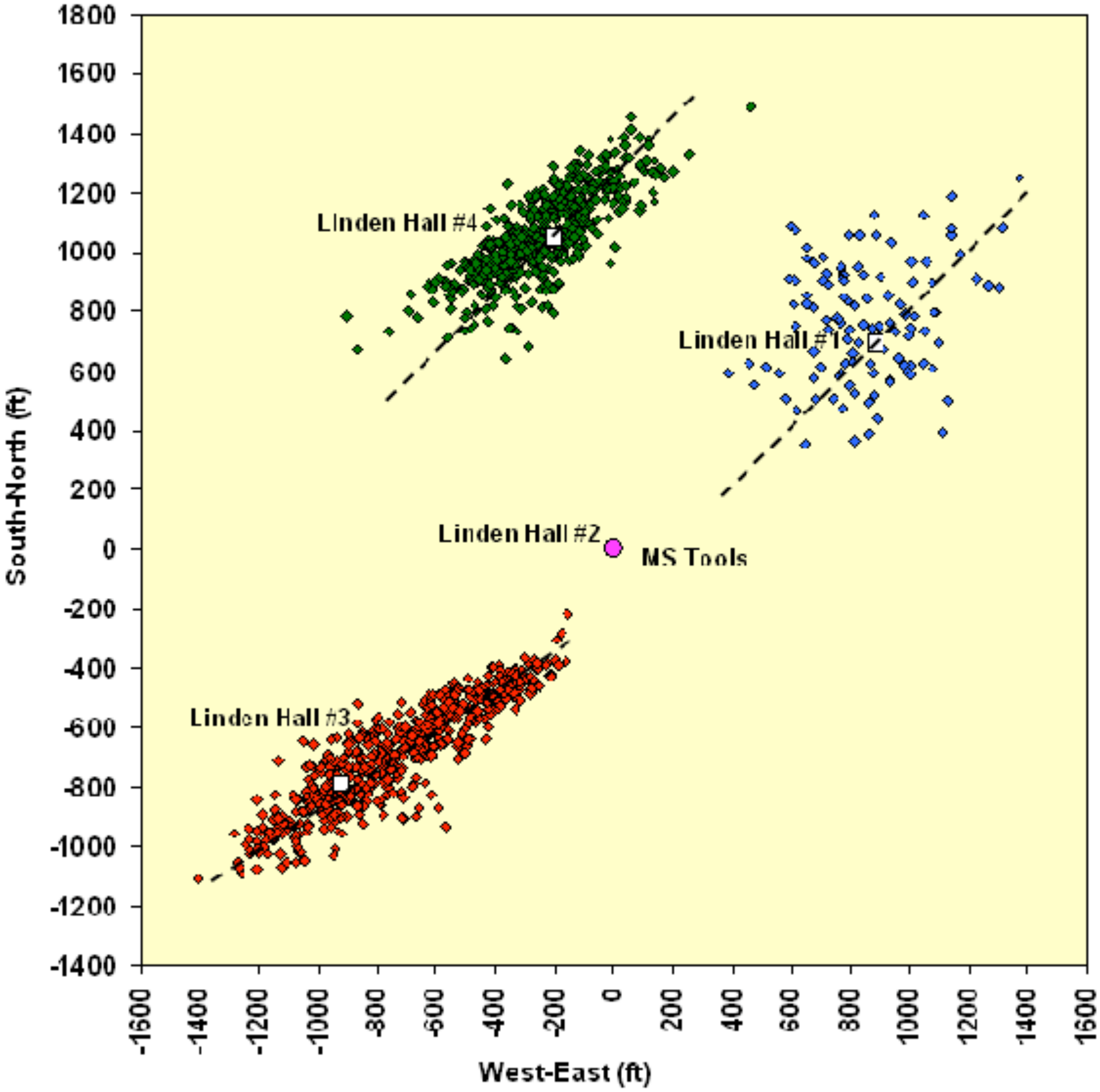

Figure 5 – Map View of Study Wells and Microseismic Events Detected

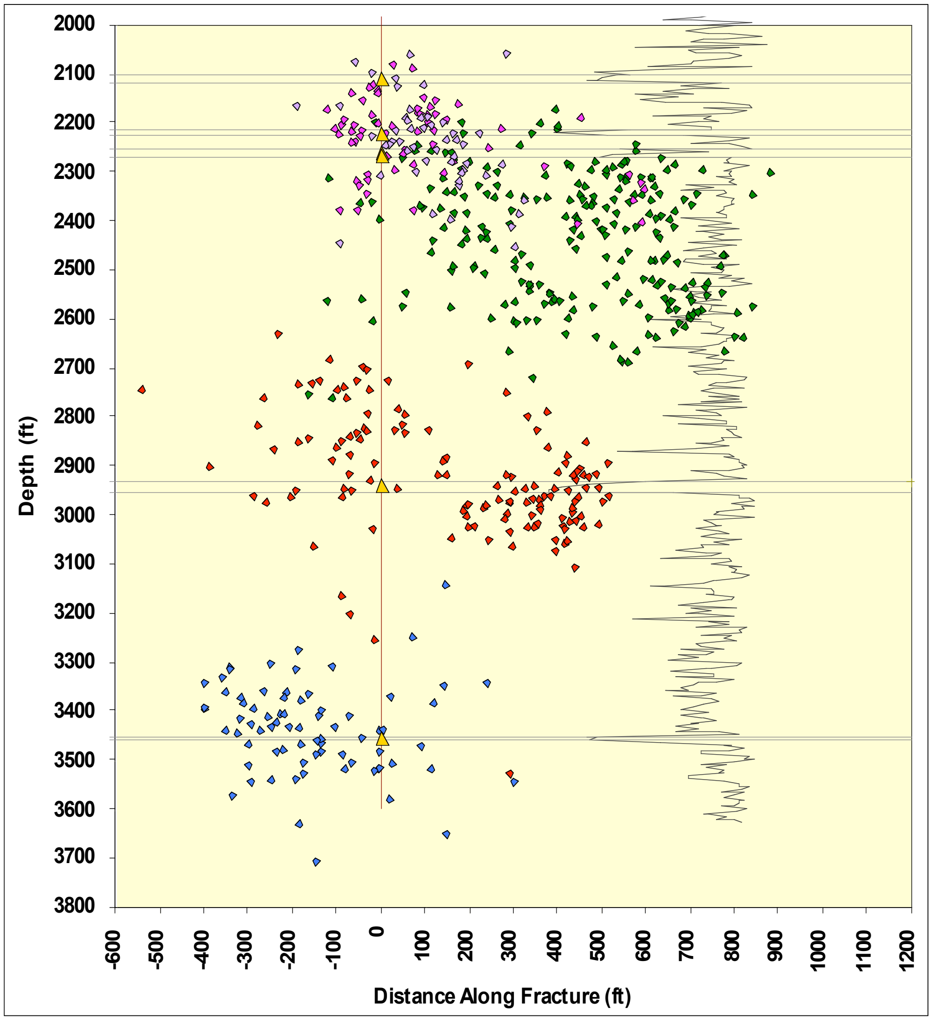

Figure 6 – Side View of Microseismic Events Detected During Stimulation of Linden Hall #3

Stage 1 Height Growth = 400 Feet, Half Length = 400 Feet, Perforated Interval = 11 Feet
Stage 2 Height Growth = 424 Feet, Half Length = 500 Feet, Perforated Interval = 8 Feet
Stage 3 Height Growth = 480 Feet, Half Length = 900 Feet, Perforated Interval = 13 Feet
Stage 4 Height Growth = 300 Feet, Half Length = 320 Feet, Perforated Interval = 51 Feet
Stage 5 Height Growth = 380 Feet, Half Length = 300 Feet, Perforated Interval = 12 Feet

		Volume	Proppant	Height	Half Length	Azimuth
LH#1	Stage1	18,889 gallons	30,500 lbs	206 feet	200 feet	N49W
	Stage 2	19,653	33,800	444	500	N45E
	Stage 3	18,140	34,300	300	300	N40W
LH#3	Stage1	28,935 gallons	56,700 lbs	400	400	N55E
	Stage 2	35,865	51,000	424	500	N55E
	Stage 3	33,817	48,000	480	900	N59E
	Stage 4	26,352	30,000	300	320	N55E
	Stage 5	36,819	52,000	380	300	N50E
LH#4	Stage1	36,299 gallons	50,000 lbs	520	600	N55E
	Stage 2	39,701	62,500	600	400	N50E
	Stage 3	30,974	45,000	475	400	N45E
	Stage 4	35,140	45,500	250	350	N40E

Table 1 – Summary of Treatment Parameters and Fracture Geometry From 12 Mapped Stages

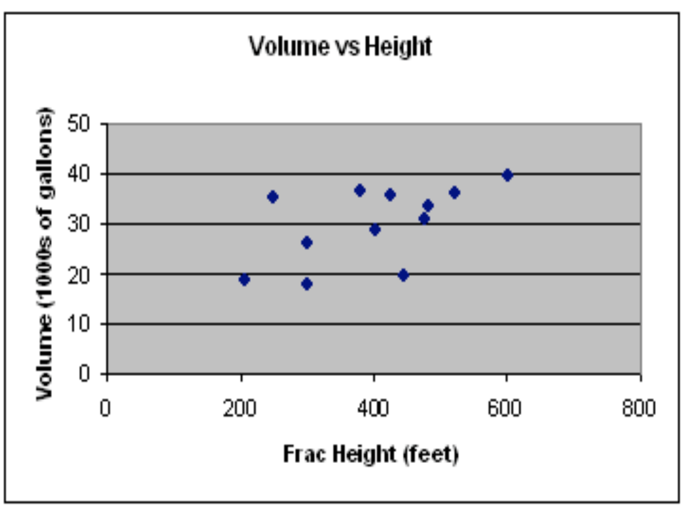

Figure 7 – Fracture Height vs Treatment Volume

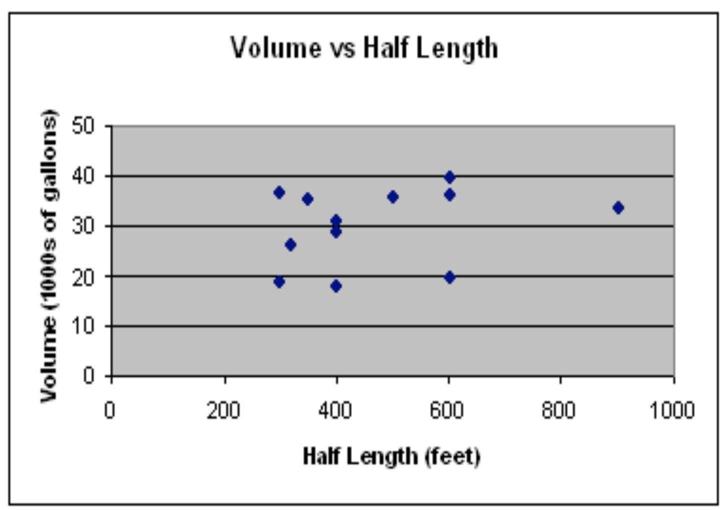

Figure 8 – Fracture Half length vs Treatment Volume

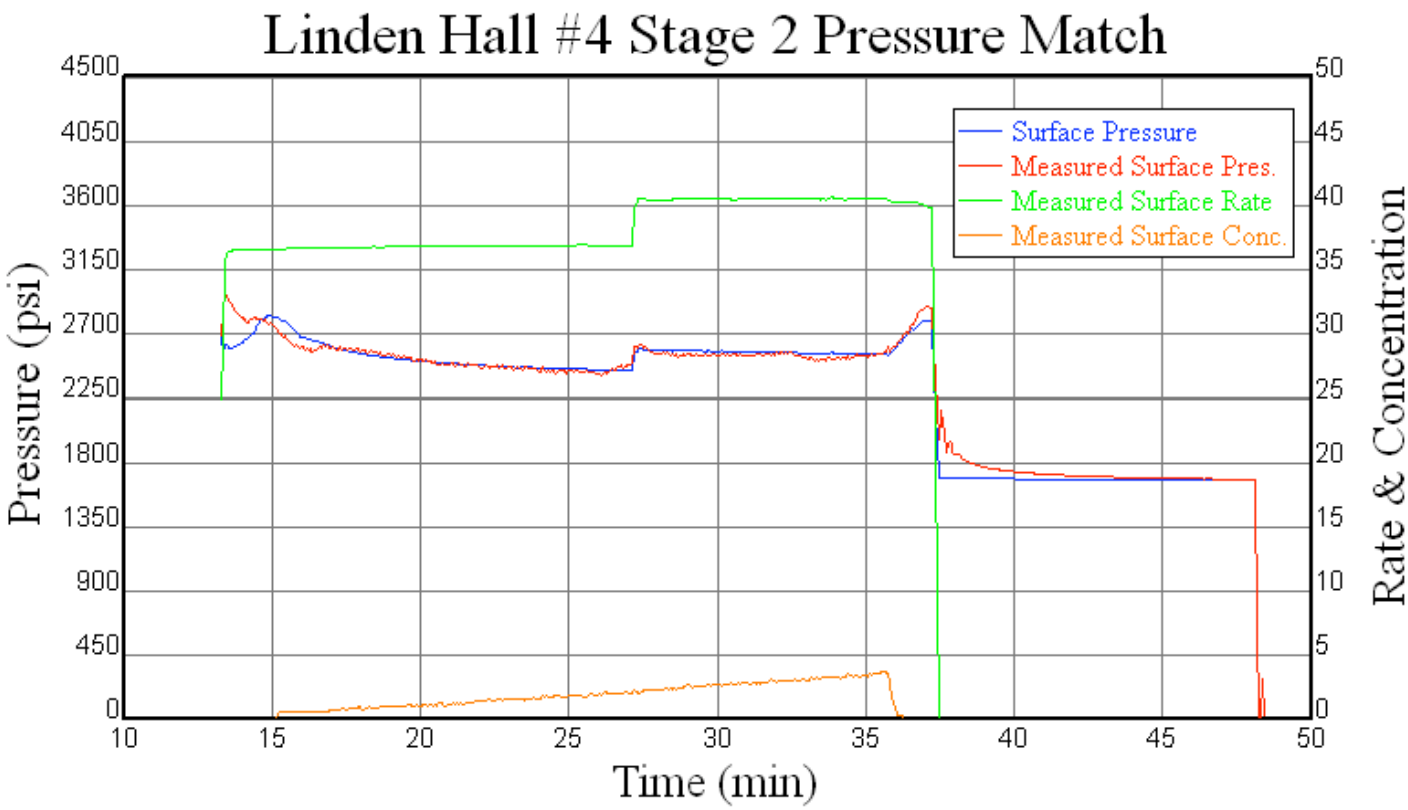

Figure 9 – Treatment Pressure History Match of Linden Hall #4, Stage #2

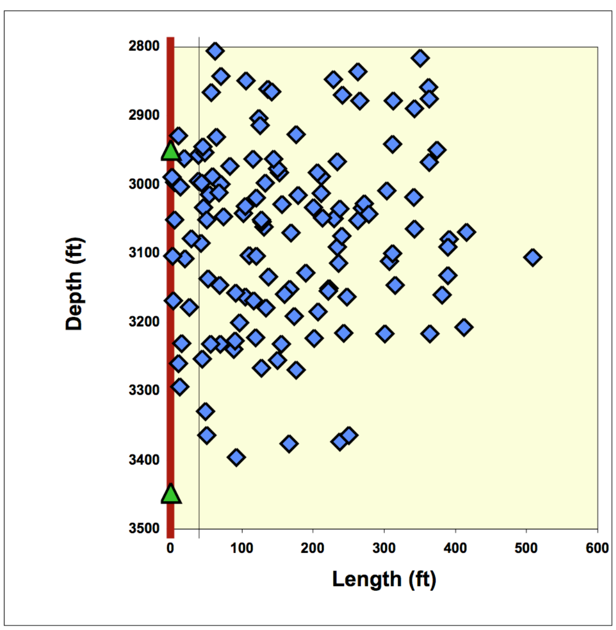

Figure 10 – Plot of Microseismic Events Mapped During Treatment of Linden Hall #4, Stage 2

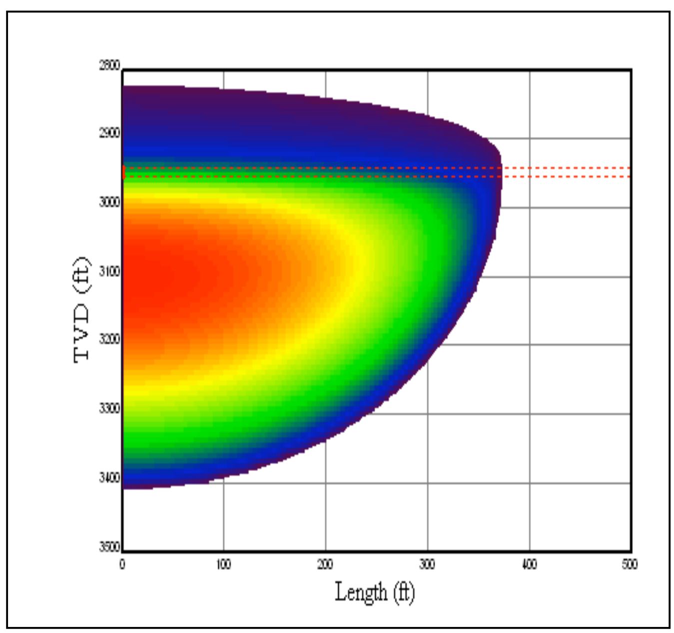

Figure 11 – Fracture Profile Generated From Fracture Model Treatment Pressure Matching