MAJOR PROJECT

ON

HYDRAULIC FRACTURING IN CBM WELLS

Submitted By

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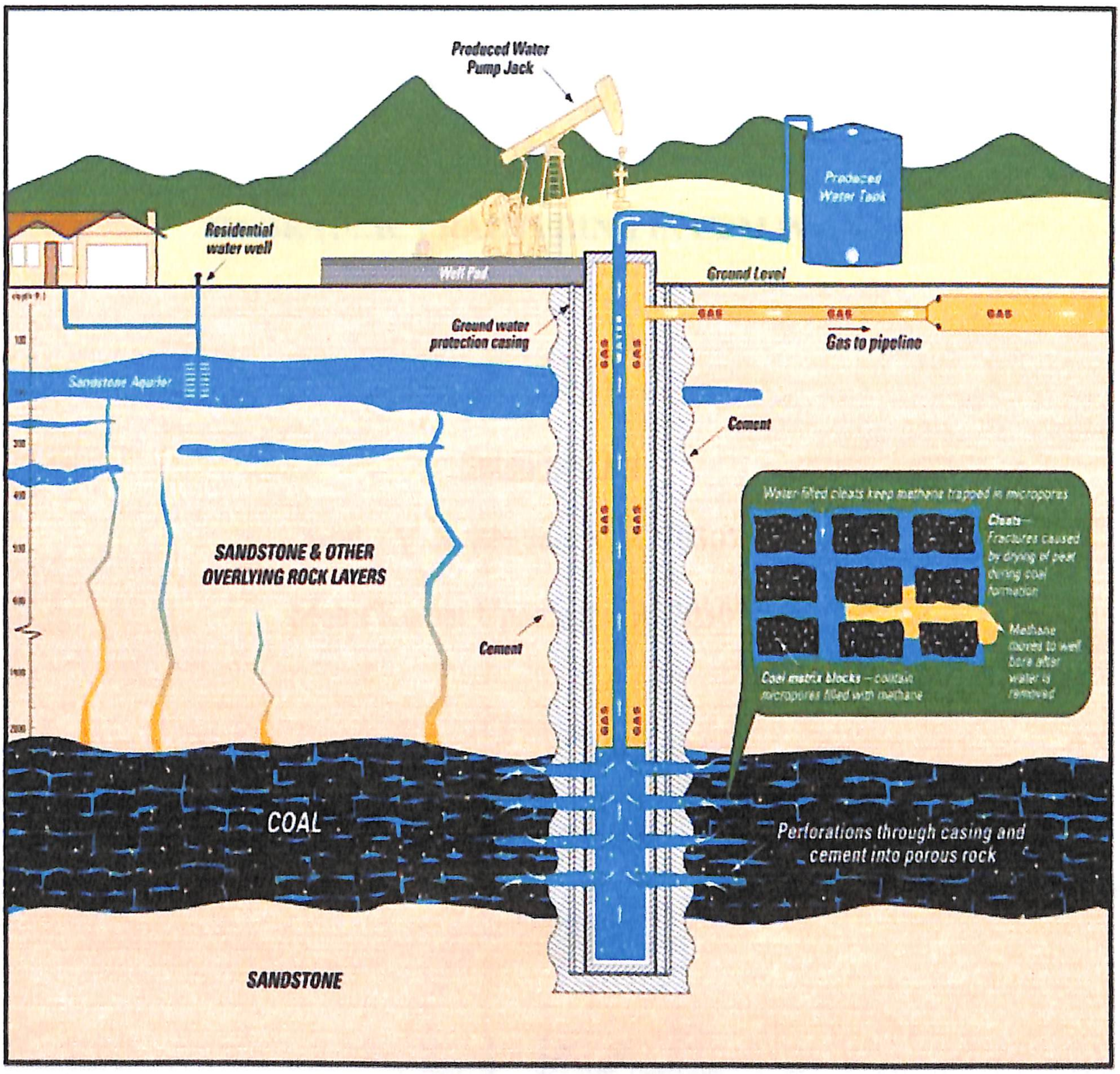

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Mohit Kumar Upadhyay **Aditya V. S. Bhadauria**

Certificate

This is to certify that Aditya V. S. Bhadauria and Mohit Kumar Upadhyay, *students of Intt. B.Tech (Applied Petroleum Engineering) + MBA (Upstream Asset Management) has written their thesis on* "**Hydraulic Fracturing in CBM Wells**" *under my supervision and have successfully completed the project within stipulated time.*

They have demonstrated high performance levels and dedication during the completion of his thesis.

Signature

16 May 2011

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Hydraulic Fracturing In Coalbed Methane Wells

Abstract

As exploitation of unconventional resources such as coalbed methane (CBM) reservoirs becomes increasingly essential, there is a growing need to develop hydraulic fracture treatment design for these reservoirs. In the case of high permeability, drilling fluids may enter the flow channels and later impair flow into the wellbore. In the cast of low permeability, the flow channels may not permit enough flow into the wellbore. In either case, the well may not be commercial because fluid cannot flow into the wellbore fast enough. It then becomes necessary to create an artificial channel that will increase the ability of the reservoir rock to conduct fluid into the wellbore. Such channels often can be created by hydraulic fracturing.

Most CBM wells require hydraulic fracturing to produce at commercial gas rates. It is important to understand that fracturing of coals is very different from fracturing conventional sandstone reservoirs. Coal is a naturally fractured material (cleat system) with very unique rock mechanical properties, and is inherently prone to complex and/or multiple fractures. This may include T-shaped, 'railroad track', or branched fractures.

This major project report includes an integrated approach to optimize hydraulic fracture treatments and addresses the associated problems encountered during the hydraulic fracturing process. Fracture fluid type, additives, In-situ stress conditions which have a large influence on the producibility of a particular coal zone is taken in to consideration.

Chapter 1

1.1 INTRODUCTION

The coalbed methane (CBM) industry began after the realization that large methane contents of coals could often be produced profitably if the seams were dewatered and if a permeable path to the wellbore could be established for the gas. Hydraulic-fracturing technology, developed in the oil and gas industry after 1948, proved to be the answer in many cases for facilitating dewatering and elevating gas production rates to economic levels.

Hydraulic fracturing is the process of pumping a fluid into a wellbore at an injection rate that is too high for the formation to accept in a radial flow pattern. As the resistance to flow in the formation increases, the pressure in the wellbore increases to a value that exceeds the breakdown pressure of the formation that is open to the wellbore. Once the formation "breaks-down", a crack or fracture is formed, and the injected fluid begins moving down the fracture. In most formations, a single, vertical fracture is created that propagates in two directions from the wellbore. These fracture "wings" are 180o apart and are normally assumed to be identical in shape and size at any point in time. In naturally fractured or cleated formations, such as gas shale or coal seams, it is possible that multiple fracture can be created and propagated during a hydraulic fracture treatment.

This chapter focuses on the following topics:

. About Coalbed methane (CBM)
. Worldwide distribution of cbm
. Cbm reserves in india
. Explored and Unexplored field present in India
. Future Coal Scenario

1.2 CBM (Coal Bed Methane)

Coalbed methane (CBM) or coalbed gas is a form of natural gas extracted from coal beds. In recent decades it has become an important source of energy in United States, Canada, and other countries including India. Methane burns more cleanly than any other fossil fuel and CBM technology has converted this significant energy source from a centuries-old mining hazard into an environmentally friendly fuel. Production of coalbed methane (CBM) in a short time has become an important industry, providing an abundant, clean-burning fuel in an age when concerns about pollution and fuel shortages preoccupy the thoughts of people around the globe. Other than in the U.S.A., CBM is being produced in Queensland, Australia and the United Kingdom. Pilot projects are underway in China and India.

The use of CBM has various possible advantages, such as providing a clean burning fuel, increasing substantially the natural gas reserve base, to improve safety of coal mining, to decrease methane vented to the atmosphere from coal mines that might affect global warming and to provide a means to use an abundant coal resource that is often too deep to mine.

Employed in the coalfields have been oilfield techniques, sometimes modified and improved. In many ways the CBM process has merged technologies from the oil industry and the coal industry. For example, during the preceding generation, methane was produced for local use from wells drilled into coals, but it took the fracturing of those coals and their dewatering, along with other oilfield technology, to increase production rates to commercial levels. Research generated by the activity delved into coal properties and associated phenomena on a scale no undertaken before for coal.

1.3 WORLDWIDE DISTRIBUTION OF CBM

On a global basis, coalbed methane now contributes more than 1TCF (trillion cubic feet) of gas per annum. Coalbed methane accounts for between 3 percent and 4 percent of all gas production in the U.S.A. Coalbed Methane resource appraisal, drilling and production testing are presently underway in at least a dozen other countries, and the proportion of non-US production can be expected to soar during the next 10 years. The world-wide reserves of CBM are estimated to be in the range of 7500 TCF.

China, the world's largest coal producer, has generated particular interest. Its coalbed methane resources are estimated to range from between 1,000 and 2,800 TCF, many times larger than its conventional gas potential. Chinese coal mine operations already extract gas from within the underground workings. Although modest, this production has demonstrated to the Chinese authorities the viability of the resource. As a result a number of areas have now been joint ventured with foreign companies with initial drilling showing promising results. On the basis in initial investigations, Bangladesh, too, is regarded as having the potential to produce moderate to large volumes of coalbed methane in close proximity to major markets.

In the Philippines and Indonesia, interest in coalbed methane is being sparked and Indonesia has about 400 TCF of reserves. Drilling success in Zimbabwe has demonstrated the commerciality of coalbed methane development in the country. In several parts of Eastern Europe, a number of coalbed methane ventures involving foreign investment and applications of U.S. technology are reported to have met with mixed success. Production tests in some regions are said to favour commercial production, which is anticipated when negotiations with regulatory authorities have been resolved. Australia is a major-player in the field of CBM, in last 12 years CBM production has increased from < 1Bcf /year to 127 Bcf /year.

The tempo of coalbed methane exploration has increased significantly in Australia since the entry of major international coalbed methane producers, such as Amoco and Conoco, and the involvement of major utilities such as Pacific Power and AGL, together with a number of smaller groups.

These efforts are backed by a major research effort which is modifying US technologies to suit local conditions.

Global coal distribution

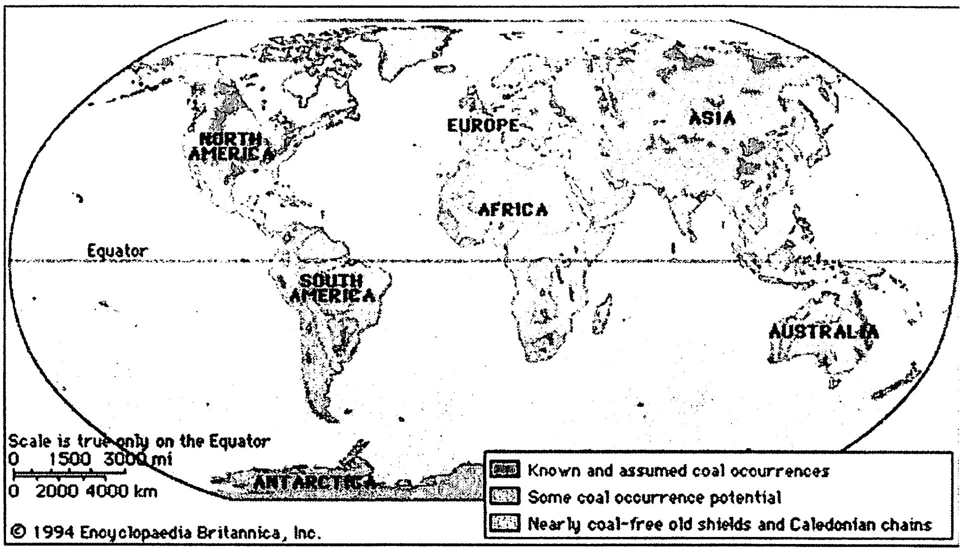
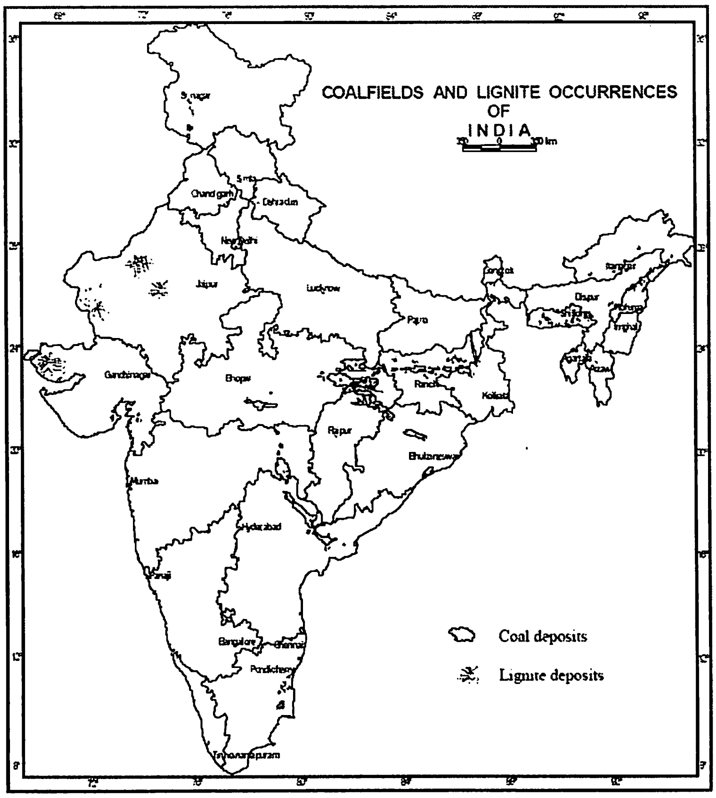


Fig 1 Global Coal Distribution

1.4 CBM RESERVES IN INDIA

India is among the top ten countries in coal resources, having an estimated coal reserve of 160 million metric tons, with an estimated methane resource of 850 BCM. The Indian coal is mainly confined to the Permian Gondwana basins and the tertiaries. Tertiary coals are widespread in Assam, Meghalaya, Arunachal Pradesh, Tamil Nadu, Rajasthan and Gujarat. Tertiary coals are generally found to be lignitic to sub-bituminous in rank and are generally considered to be unsuitable for coalbed methane target. However, tertiary coals in petroliferous basins of Cambay, Upper Assam and Assam–Arakan may be prospective due to reported higher gas content, which is probably stored in the coal after generation from deeper-lying hydrocarbon source beds or may be of biogenic origin. Methane emission studies from working mines of India reported most of the degree three gassy mines (> 10 cubic m/ton), are confined in the four Damodar Valley coal fields, viz. Raniganj, Jharia, Bokaro and North Karanpura in Bihar and West Bengal. In these areas, the thickest bituminous coals are extensively developed in the Barakar measurers and in Raniganj measures of Lower and Upper Permian age, respectively.

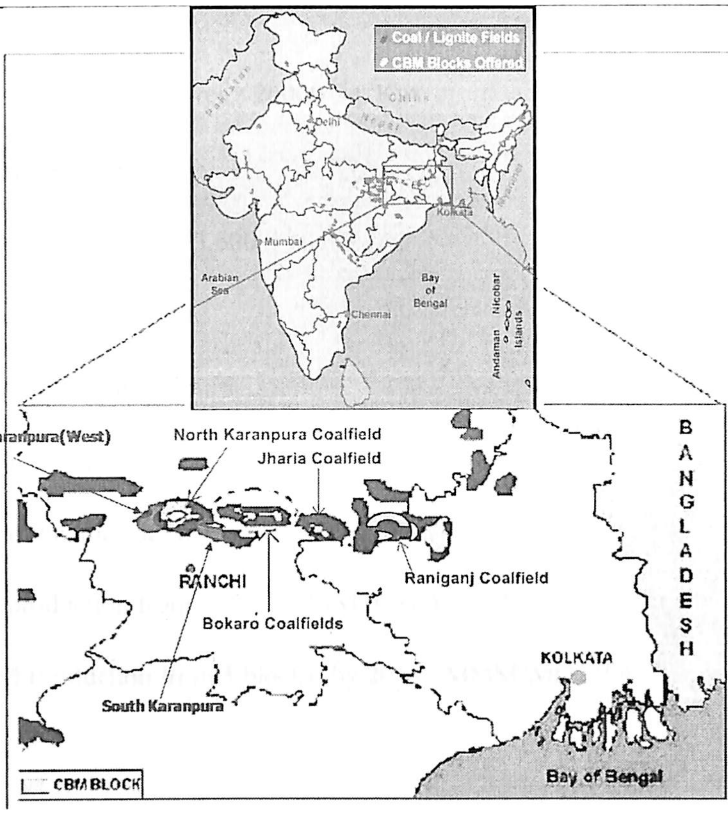


1.5 State wise CBM Resources in India

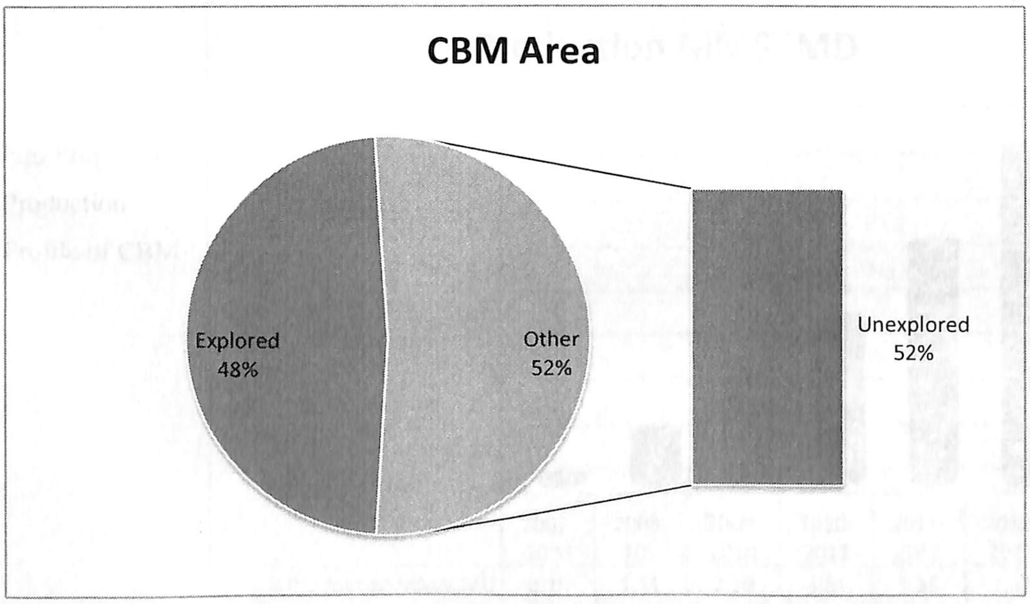
State	Estimate CBM Resource in (TCF)
Andhra Pradesh	3.50
Chattisgarh	8.50
Gujrat	12.40
Jharkand	25.50
Madhya Pradesh	7.70
Maharastra	1.20
North East	0.30
Orrisa	8.60
Rajasthan	12.70
Tamilnadu	3.70
West Bengal	7.70
Total	**91.80**

1.6 State Wise Blocks

State	Number Of Blocks
Jharkhand	6
West Bengal	4
Madhya Pradesh	5
Rajasthan	4
Chattisgarh	3
AndraPradesh	2
Maharastra	1
Gujtrat	1
Total	**26**



CBM Blocks in Damodar Valley



Exploration Status of CBM

Total available Coal Bearing Area : 26000 Sq. Km

Status of CBM Exploration

Area Opened Up ,Sq Km : 13,600

Total Resources , BCM : 1374

CBM wells Drilled so far : 230

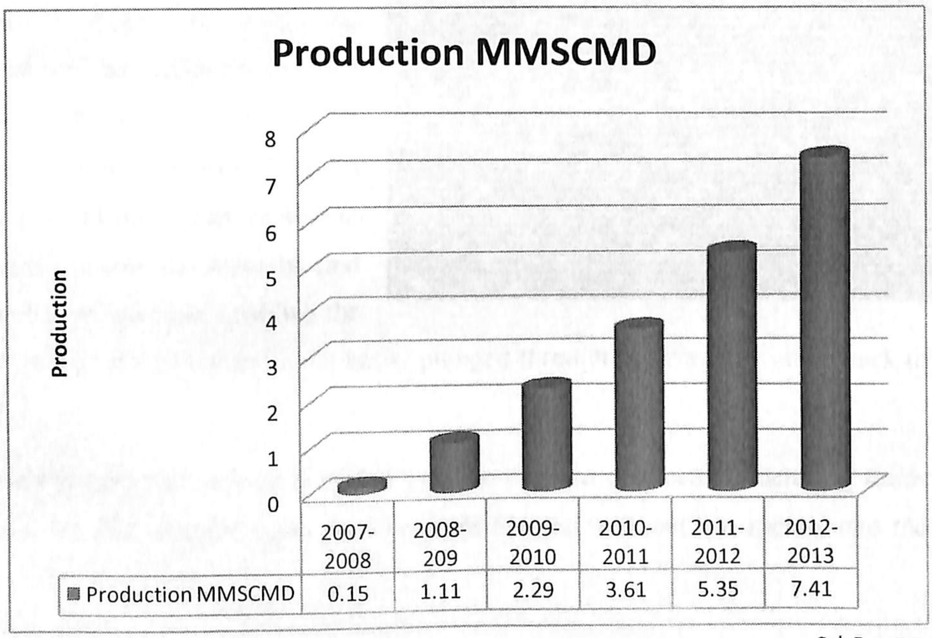
Expected production potential MMSCMD : 38

Commercial Production started from : 14.07.2007

Presented gas production from 3 blocks ,MMSCMD : 0.14

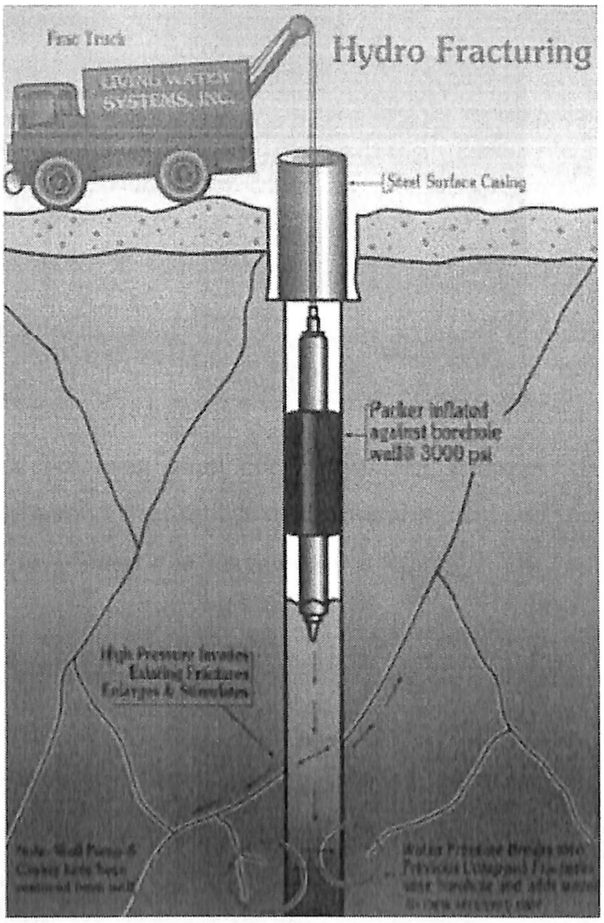
Expected CBM Production from 3 blocks by 2013 , MMSCMD : 7.4

Fig. Projected Production Profile of CBM



Chapter 2

2.1 Basics of Hydraulic Fracturing in CBM



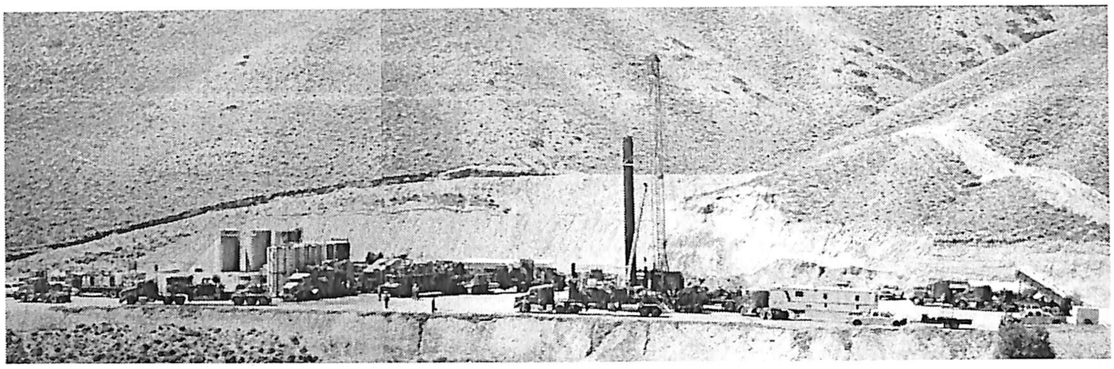
Coal is defined as a rock which contains at least 50 % organic matter by weight. The precursor of coal is peat, plant matter deposited over time in fresh-water swamps associated with coastal deltaic rivers. The coal resources from which coalbed methane is derived have similar geologic origins.

Coals are usually found in geologic formations that are approximately 65-325 million years old. Coal formation occurred during a time of moderate climate and broad inland oceans.

Hydraulic fracturing is a technique used by the oil and gas industry to improve the production efficiency of oil and coalbed methane wells. The extraction of coalbed methane is enhanced by hydraulically enlarging and/or creating fractures in the coal zones. The resulting fracture system facilitates pumping of groundwater from the coal zone, thereby reducing pressure and enabling the methane to be released from the coal and more easily pumped through the fracture system back to the well.

To initiate the process, a production well is drilled into the targeted coal beds. Fracturing fluids containing proppants are then injected under high pressure into the well and specifically into the targeted coal beds in the subsurface.

The fracturing fluids are injected into the subsurface at a rate and pressure that are too high for the targeted coal zone to accept. As the resistance to the injected fluids increases, the pressure in the injecting well increases to a level that exceeds the breakdown pressure of the rocks in the targeted coal zone, and the rocks "breakdown". In this way, the hydraulic fracturing process "fractures" the coalbeds (and sometimes other geologic strata within or around the targeted coal zones.

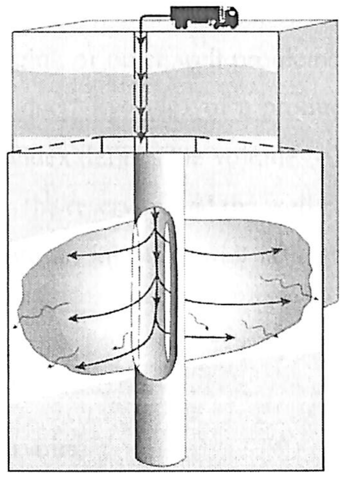


This process sometimes can create new fractures, but most often opportunistically enlarges existing fractures, increasing the connections of the natural fracture networks in and around the coalbeds. The pressure-induced fracturing serves to connect the network of fractures in the coalbeds to the hydraulic fracturing well.

The fracturing fluids pumped into the subsurface under high pressure also deliver and emplace the "proppant." The most common proppant is fine sand; under pressure, the sand is forced into the natural and/or enlarged fractures and acts to "prop" open the fractures even after the fracturing pressure is reduced. The increased permeability due to fracturing and proppant emplacement facilitates the flow and extraction of methane from coalbeds.

Methane within coalbeds is not structurally "trapped" by overlying geologic strata, as in the geologic environments typical of conventional gas deposits. Only about 5 to 9 percent of the coalbed methane is present as "free" gas within the joints and cleats of coalbeds. Most of the coalbed methane is contained within the coal itself .

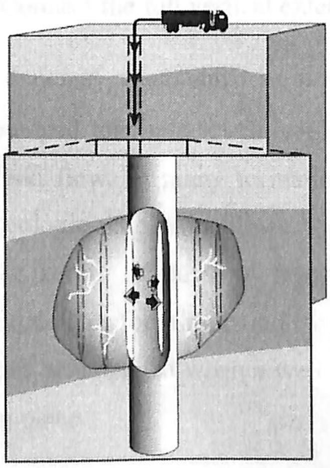
Before coalbed methane production begins, groundwater and injected fracturing fluids are first pumped out from the network of fractures in and around the coal zone. The fluids are pumped until the pressure declines to the point that methane begins to adsorb from the coal.



Coalbed methane production initially requires pumping and removing significant amounts of water to sufficiently reduce the hydrostatic pressure in the subsurface so that methane can absorb from the coal before methane extraction can begin. Coalbed methane is produced at close to atmospheric pressure. .In contrast, in the production of conventional petroleum-based gas, the production of gas is initially high, and as gas production continues over time and the gas resources are progressively depleted, gas production decreases and the amount of water pumped increases.

2.2 Why Fracturing Coals...??

Almost every coalbed targeted for methane production must be hydraulically fractured to connect the production well bore to the coalbed fracture network. Although the general hydraulic fracturing process is generally similar across the country, the details of the process can differ significantly from location to location depending on the site-specific geologic conditions. For example, although most hydraulic fracturing wells are completely cased except for openings at the targeted coal zone, many wells in the San Juan Basin are fractured by creating a cavity in the open-hole section. Also, in contrast to the typical fracturing job, many wells in the Black Warrior Basin are stimulated more than once. Here, when wells are open to multiple coal seams, the hydraulic fracturing process may involve several or multiple fracturing events, using from 2 to 5 hydraulic fracture treatments per well (depending on number of seams and spacing between seams).



Many coalbed methane wells are re-fractured at some time after the initial treatment in an effort to re-connect the wellbore to the production zones to overcome plugging or other well problems. In general, hydraulic fracture treatments are used to increase the productivity index of a producing well or the injectivity index of an injection well. The productivity index defines the volumes of oil or gas that can be produced at a given pressure differential between the reservoir and the well bore. The injectivity index refers to how much fluid can be injected into an injection well at a given pressure differential.

There are many different applications for hydraulic fracturing, such as:

•Increase the flow rate of oil and/or gas from low permeability reservoirs,

• Increase the flow rate of oil and/or gas from wells that have been damaged,

•Connect the natural fractures and/or cleats in a formation to the wellbore,

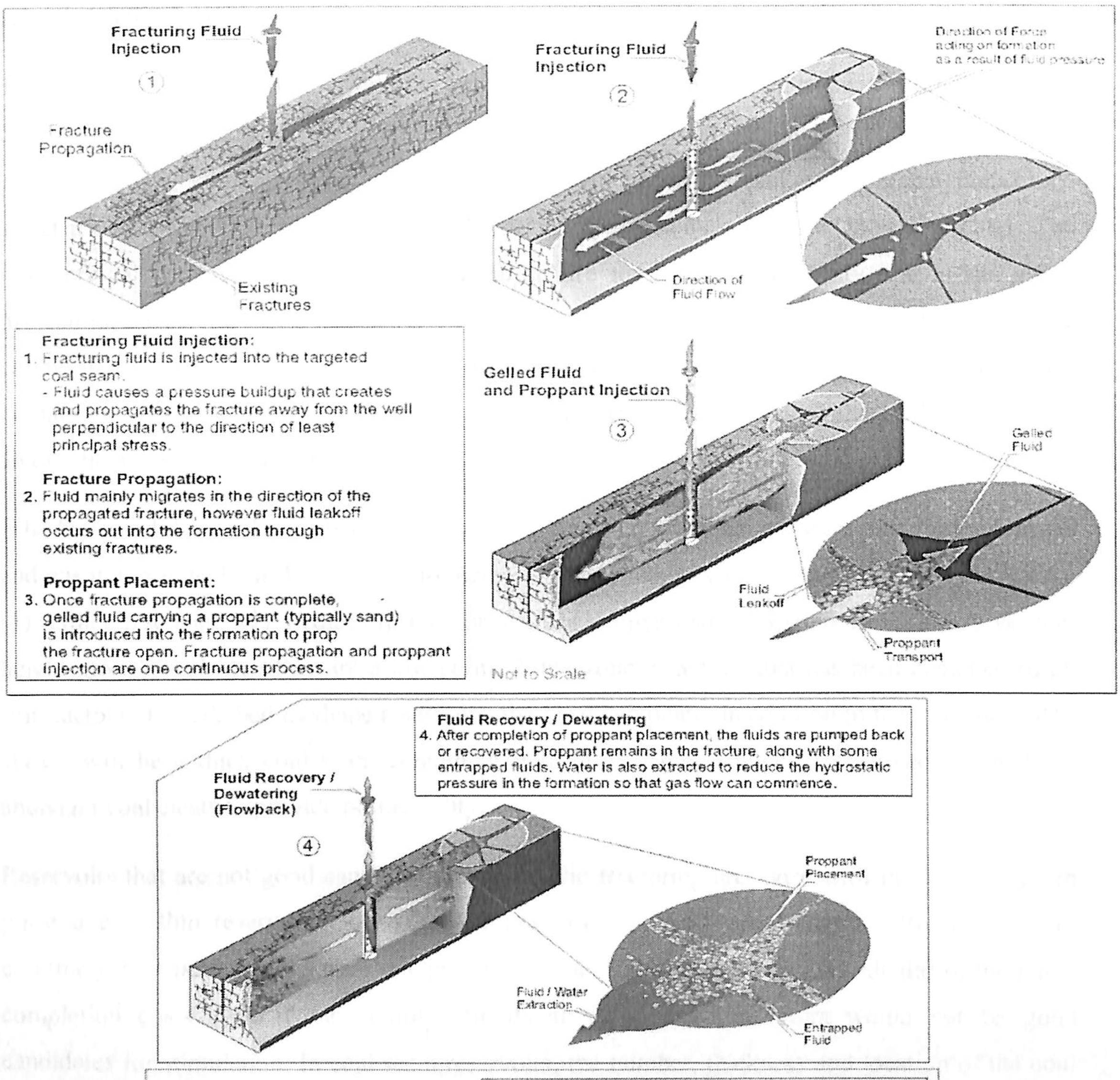
•Decrease the pressure drop around the well to minimize sand production,

• Decrease the pressure drop around the well to minimize problems with asphaltine and/or paraffin deposition,

• Increase the area of drainage or the amount of formation in contact with the wellbore, and

•Connect the full vertical extent of a reservoir to a slanted or horizontal well.

Obviously, there could be other uses of hydraulic fracturing, but the majority of the treatments are pumped for these seven reasons. A low permeability reservoir is one that has a high resistance to fluid flow. In many formations, chemical and/or physical processes alter a reservoir rock over geologic time. Sometimes, these digenetic processes restrict the openings in the rock and reduce the ability of fluids to flow through the rock. Low permeability rocks are normally excellent candidates for stimulation by hydraulic fracturing. Regardless of the permeability, a reservoir rock can be damaged when a well is drilled through the reservoir and when casing is set and cemented in place.



Fracturing Fluid Injection
1
Fracture Propagation
Existing Fractures
Fracturing Fluid Injection
2
Direction of Force acting on formation as a result of fluid pressure
Direction of Fluid Flow
Fracturing Fluid Injection:
1. Fracturing fluid is injected into the targeted coal seam.
- Fluid causes a pressure buildup that creates and propagates the fracture away from the well perpendicular to the direction of least principal stress.
Fracture Propagation:
2. Fluid mainly migrates in the direction of the propagated fracture, however fluid leakoff occurs out into the formation through existing fractures.
Proppant Placement:
3. Once fracture propagation is complete, gelled fluid carrying a proppant (typically sand) is introduced into the formation to prop the fracture open. Fracture propagation and proppant injection are one continuous process.
Gelled Fluid and Proppant Injection
3
Gelled Fluid
Fluid Leakoff
Proppant Transport
Not to Scale
Fluid Recovery / Dewatering
4. After completion of proppant placement, the fluids are pumped back or recovered. Proppant remains in the fracture, along with some entrapped fluids. Water is also extracted to reduce the hydrostatic pressure in the formation so that gas flow can commence.
Fluid Recovery / Dewatering (Flowback)
4
Proppant Placement
Fluid / Water Extraction
Entrapped Fluid
Methane Production
5. The flowback process initiates the recovery of fracturing fluids and the withdrawal of ground water out of the formation. Methane gas extraction follows.
Methane Extraction
5
Methane Flow

2.3 Well Selection

The success or failure of a hydraulic fracture treatment often depends on the quality of the candidate well selected for the treatment. Choosing an excellent candidate for stimulation often ensures success, while choosing a poor candidate will normally result in economic failure. To select the best candidate for stimulation, the design engineer must consider many variables. The most critical parameters for hydraulic fracturing are formation permeability, the in-situ stress distribution, reservoir fluid viscosity, skin factor, reservoir pressure, reservoir depth and the condition of the wellbore. The skin factor refers to whether the reservoir is already stimulated or, perhaps is damaged. If the skin factor is positive, the reservoir is damaged and could possibly be an excellent candidate for stimulation.

The best candidate wells for hydraulic fracturing treatments will have a substantial volume of oil and gas in place, and will have a need to increase the productivity index. Such reservoirs will have (1) a thick pay zone, (2) medium to high pressure, (3) in-situ stress barriers to minimize vertical height growth, and (4) either are a low permeability zone or a zone that has been damaged (high skin factor). For coalbed methane reservoirs, the ideal candidate, in addition to the 4 factors listed above, will be a thick coal seam containing both (1) a large volume of adsorbed gas and (2) abundant coal cleats to provide permeability.

Reservoirs that are not good candidates for hydraulic fracturing are those with little oil or gas in place due to thin reservoirs, low reservoir pressure, or small aerial extent. Reservoirs with extremely low permeability may not produce enough hydrocarbons to pay all the drilling and completion costs even if successfully stimulated; thus, such reservoirs would not be good candidates for stimulation. In coal seam reservoirs, the number, thickness and location of the coal seams must be considered when deciding if the coals can be completed and stimulated economically. If the coal seams are too thin or too scattered up and down the hole, the coals may not be ideal candidates for stimulation by hydraulic fracturing.

2.4 Developing Data Sets

For most petroleum engineering problems, developing a complete and accurate data set is often the most time consuming part of solving the problem. For hydraulic fracture treatment design, the data required to run both the fracture design model and the reservoir simulation model can be divided into two groups.

One group lists the data that can be "controlled" by the engineer. The second group reflects data that must be measured or estimated, but cannot be controlled. The primary data that can be controlled by the engineer are the well completion details, treatment volume, pad volume, injection rate, fracture fluid viscosity, fracture fluid density, fluid loss additives, propping agent type, and propping agent volume. The data that must be measured or estimated by the design engineer are formation depth, formation permeability, in-situ stresses in the pay zone, in-situ stresses in the surrounding layers, formation modulus, reservoir pressure, formation porosity, formation compressibility, and the thickness of the reservoir.

The most critical data for the design of a fracture treatment are, roughly in order of importance, (1) the in-situ stress profile, (2) formation permeability, (3) fluid loss characteristics, (4) total fluid volume pumped, (5) propping agent type and amount, (6) pad volume, (7) fracture fluid viscosity, (8) injection rate, and (9) formation modulus. Since most engineers have more work to do than time to do the work, the design engineer should focus most of his time on the most important parameters.

In new fields or reservoirs, most operating companies are normally willing to spend money to run logs, cut cores and run well tests to determine important factors such as the in-situ stress and the permeability of the major reservoir layers. By using such data, along with fracture treatment records and production records, accurate data sets for a given reservoir in a given field can normally be compiled. These data sets can be used on subsequent wells to optimize the fracture treatment designs. It is normally not practical to cut cores and run well tests on every well. Thus, the data obtained from cores and well tests must be correlated to log parameters so the logs on subsequent wells can be used to compile accurate data sets.

To design a fracture treatment, most engineers use pseudo 3-dimensional (P3D) models. Full 3D models exist; however, the use of full 3-D models is currently limited to supercomputers and research organizations. To use a P3D model, the data must be input by reservoir layer.

In some cases, coal seams will prevent fractures from growing vertically. Many coal seams are highly cleated, and when the fracture fluid enters the coal seam, it remains contained within the coal seam. In thick, highly cleated coal seams, the growth of the hydraulic fracture will normally be limited to the coal seam.The data used to design a fracture treatment can be obtained from a number of sources, such as drilling records, completion records, well files, open hole geophysical logs, cores and core analyses, well tests, production data, geologic records, and other public records, such as publications. In addition, service companies provide data on their fluids, additives and propping agents.

Table 1 illustrates typical data needed to design a fracture treatment and possible sources for the data.

DATA	UNIT	SOURCE
Formation Permeability	Md	Cores,Well Tests Correlations, Production Data
Formation Porosity	%	Cores, Logs
Reservoir Pressure	Psi	Well Tests, Well Files, Regional Data
Formation Modulus	Psi	Cores, Logs, Correlations
Formation Compressibility	Psi	Cores, Logs, Correlations
Poisson's Ratio		Cores, Logs, Correlations
Formation Depth	Ft	Logs, Drilling Records
In-situ Stress	Psi	Well Tests, Logs, Correlations
Formation Temperature	°F	Logs, Well Tests, Correlations
Fracture Toughness	psi	Cores, Correlations

Water Saturation	%	Logs.' Cores
Net Pay Thickness	Ft	Logs. Cores
Gross Pay Thickness	Ft	Logs, Cores, Drilling Records
Formation Lithology		Cores. Drilling Records, Logs, Geologic Records
Wellbore Completion		Well Files. Completion Prognosis
Fracture Fluids		Service Company Information
Fracture Proppants		Service Company Information

2.5 Properties of Coalbeds and Surrounding Formations

Coalbed depth and rock types in the coal zone have important fundamental influences on fracture dimensions and orientations. At depths of less than 1,000 feet, the direction of least principal stress tends to be vertical and, therefore, at these relatively shallow depths fractures typically have more of a horizontal than a vertical component.

Here, horizontal fractures tend to be created because the hydraulically induced pressure forces the walls of the fracture to open in the direction of least stress, creating a horizontal fracture. At these shallower depths, the horizontal fractures result from the low vertical stress due to the relatively low weight of overlying geologic material. Generally, in locations deeper than 1,000 feet, the least principal stress tends to be horizontal so vertical fractures tend to form. Vertical fractures created in these greater depths can propagate vertically to shallower depths and develop a horizontal component, In many coalbed methane basins, the depths, lithologic properties, and stress fields of the coal zones result in hydraulic fractures that are higher than they are long.

Naceur and Touboul state that the primary mechanisms controlling fracture height are contrasts in the physical properties of the rock strata within and surrounding the coal zone being fractured. Leakoff is the magnitude of pressure exerted on a formation that causes fluid to be forced into the formation. The fluid may be flowing into the pore spaces of the rock or into cracks opened and propagated into the formation by the fluid pressure. Toughness can be defined as the point at which enough stress intensity has been applied to a rock formation, so that a fracture initiates and propagates.

Another factor controlling fracture height can be the highly cleated nature of some coalbeds. In some cases, highly cleated coal seams will prevent fractures from growing vertically. When the fracturing fluid enters the coal seam, it is contained within the coal seam's dense system of cleats and the growth of the hydraulic fracture will be limited to the coal seam.

The low permeability of relatively unfractured shale may help to protect drinking water from being affected by hydraulic fracturing fluids in some basins. If sufficiently thick and relatively unfractured shales are present, they may act as a barrier not only to fracture height growth, but also to fluid movement. The lithology of coalbeds and surrounding formations is variable in the basins where coalbed methane is produced. Although common, the idealized coal cycle (with shales overlying coalbeds) is not always present in all coal basins or necessarily in all parts of any basin.

Differences in fracture behavior may also be due in part to very small layers or irregularities that exist in the rocks as part of the sedimentation process that created them. Therefore, a valid measurement of rock properties relevant to fracture behavior at one location may not adequately represent the properties of similar rock at another location. According to Warpinski, even microscopically-thin ash beds can influence hydraulic fracture propagation.

2.6 Natural Fracture Systems

Steidl, based on his "mined-through" studies, concluded that high coalbed methane production depends greatly on the presence of pre-existing natural fracture systems. Hydraulic fracturing tends to widen naturally occurring planes of weakness and rarely creates new fractures, as based on observations by Diamond and Diamond and Oyler in their mined-through studies.

Diamond and Oyler also noted that this opportunistic enlarging of preexisting fractures appears to account for those cases where hydraulic fractures propagate from the targeted coalbeds into overlying rock, and their studies found penetration into overlying layers in nearly half of the fractures intercepted by underground mines. Importantly, in several locations in the Diamond study sites, fluorescent paint was injected along with the hydraulic fracturing fluids and the paint was found in natural fractures from 200 to slightly more than 600 feet beyond the sand-filled ("propped") portions of hydraulically induced or enlarged fractures. It suggests that the induced/enlarged fractures link into the existing fracture network system and those hydraulic fracturing fluids can move beyond, and sometimes significantly beyond, the propped, sand-filled portions of hydraulically induced fractures. The mined-through studies did not conduct systematic assessments of the extent of the fractures into or through the roof rock shales that were immediately above the mined coal.

3.1 Fracture Mechanics

Fracture mechanics has been part of mining engineering and mechanical engineering for hundreds of years. No one is more interested in underground rock fractures than a miner working in an underground mine. In petroleum engineering, we have only used fracture mechanics theories in our work for about 50 years. Much of what we use in hydraulic fracturing theory and design has been developed by other engineering disciplines many years ago. However, certain aspects, such as poroelastic theory, are unique to porous, permeable underground formations. The most important parameters are in-situ stress, Poisson's ration, and Young's modulus.

3.2 Basic Rock Mechanics

The mechanical properties of the coal determine the reaction of the rock to imposed stresses of fracturing. Elastic properties determine the effect of imposed or in-situ stresses on existing natural fractures or previously created hydraulic fractures, directly affecting the permeability of the rock system. In coalbed reservoirs, rock mechanical properties and related stresses are of great concern.

Young's modulus is an elastic property of rock defined by that gives a measure of fractional elongation as a consequence of stress imposed on the rock.

$$E_x = \frac{\sigma_x}{\varepsilon_x}$$

Where

Ex = Young's modulus (psi)

σx = stress, x direction (psi)

εx = strain (x direction)

3.3 Stress

In-situ minimum stress differences of strata limit fracture height growth, and large differences in the strata of Young's modulus limit fracture height growth. Coal usually has a much smaller Young's modulus than the surrounding rock, and A vertical fracture propagates perpendicular to the minimum horizontal stress and is limited in height by bounding strata of high stress.

Fracture height is controlled by in-situ stresses of the formations A horizontal component of the fracture may be created at the coal and roof rock interface if the shear strength, τ, of the interface described by Eq is less than the tensional stress of the propagating fracture. Therefore, if a low coefficient of friction of the interface or a low normal stress acting on the interface or the product of these two parameters are present, slippage at the interface will occur to terminate the vertical growth of the fracture. The amount and type of fill material at the interface and the rugosity of the two faces determine τo and μf. The normal stress decreases at shallower depths.

$$\tau = \tau_o + \mu_f \sigma_n$$

where

τ = shear stress at interface to overcome cohesive and friction forces

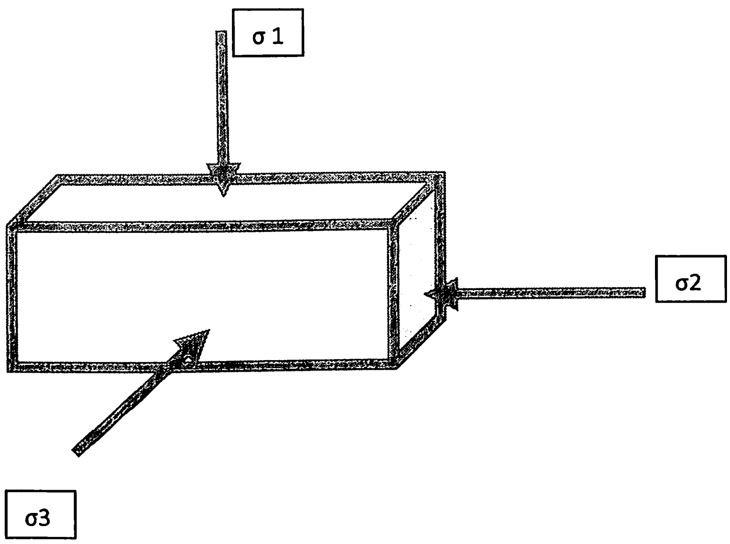
τo = cohesive shear strength of interface

σn = normal stress

μf= coefficient of friction

3.4 In-situ Stresses

Underground formations are confined and under stress. Fig. 3 illustrates the local stress state at depth for an element of formation. The stresses can be divided into 3 principal stresses. As shown $\sigma 1$ is the vertical stress, $\sigma 2$ is the maximum horizontal stress, while $\sigma 3$ is the minimum horizontal stress, where $\sigma 1 > \sigma 2 > \sigma 3$. This is a typical configuration for coalbed methane reservoirs. However, depending on geologic conditions, the vertical stress could also be the intermediate (σ2) or minimum stress (σ3). These stresses are normally compressive and vary in magnitude throughout the reservoir, particularly in the vertical direction (from layer to layer). The magnitude and direction of the principal stresses are important because they control the pressure required to create and propagate a fracture, the shape and vertical extent of the fracture, the direction of the fracture, and the stresses trying to crush and/or embed the propping agent during production. A hydraulic fracture will propagate perpendicular to the minimum principal stress (σ3). If the minimum horizontal stress is σ3, the fracture will be vertical and, we can compute the minimum horizontal stress profile with depth using equations.



The three principal compressive stresses.

$$\sigma_{min} \cong \frac{\nu}{1-\nu}\left(\sigma_{ob} - \alpha\,\sigma_p\right) + \alpha\,\sigma_p + \sigma_{ext}$$

Where:

σ min = the minimum horizontal stress (in-situ stress)

ν = Poissons' ratio

σob = overburden stress

α = Biot's constant

σp = reservoir fluid pressure or pore pressure

σext = tectonic stress

Poisson's ratio can be estimated from acoustic log data or from correlations based upon litho logy. For coal seams, the value of Poisson's ratio will range from 0.2 – 0.4. The overburden stress can be computed using density log data. Normally, the value for overburden pressure is about 1.1 psi per foot of depth. The reservoir pressure must be measured or estimated. Blot's constant must be less than or equal to 1.0 and typically ranges from 0.5 to 1.0. The first two (2) terms on the right hand side of Equations represent the horizontal stress resulting from the vertical stress and the Poroelastic behavior of the formation.

The tectonic stress term is important in many areas where plate tectonics or other forces increase the horizontal stresses. Poroelastic theory can be used to determine the minimum horizontal stress in tectonically relaxed areas and combines the equations of linear elastic stress-strain theory for solids with a term that includes the effects of fluid pressure in the pore space of the reservoir rocks The fluid pressure acts equally in all directions as a stress on the formation material. The "effective stress" on the rock grains is computed using linear elastic stress-strain theory.

3.5 Determining Stress Values

Stress profiles of the coal and other rock strata between coal groups may be obtained by pump-in microfracture tests. Microfractures involve pumping a small volume of fluid into the formation and measuring the instantaneous shut-in pressure (ISIP), which is close to the value of the minimum horizontal stress. The method is reliable when used in low-permeability rock having less than 1 md ofrestricted leakoff. Microfracturing provides stress measurements for the few discrete points tested. The procedure is relatively expensive and often neglected. However, an increasing emphasis is being placed on importance of in-situ stresses to CBM production.

Two important series of in-situ, state-of-stress (ISSOS) tests were conducted for the GRI .The steps used in their microfracture techniques were similar in each basin. The procedure is summarized as follows:

1. Isolate the test interval of the formation with straddle packers.

2. Inject 10–20 gal of fresh water at 4–6 gal/min.

3. Break the formation.

4. Extend the fracture at constant pressure for 1 minute.

5. After shut-in, monitor the pressure decline.

6. Take the ISIP as the minimum horizontal stress.

Lithology	Young's Modulus
Soft Sandstone	2-5 x 10^6 psi
Hard Sandstone	6-10 x 10^6 psi
Limestone Coal	8-12 x 10^6 psi
Coal	0.1-1 x 10^6 psi
Shale	1-10 x 10^6 psi

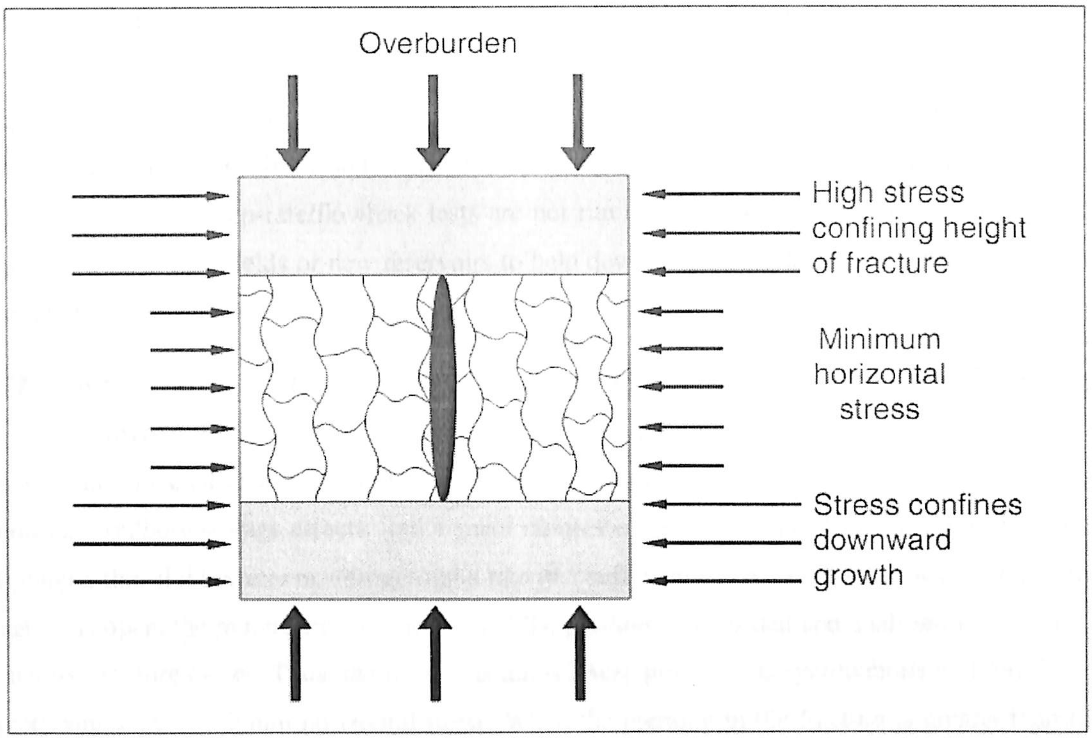


Fig : Fracture height confined by stresses.

3.6 Fracture Orientation.

A hydraulic fracture will propagate perpendicular to the least principle stress. In some shallow formations, the least principal stress is the overburden stress; thus, the hydraulic fracture will be horizontal. Horizontal fractures have been documented. In reservoirs deeper than approximately 1,000 ft, the least principal stress will likely be horizontal; thus, the hydraulic fracture will be vertical. The azimuth orientation of the vertical fracture will depend on the azimuth of the minimum and maximum horizontal stresses.

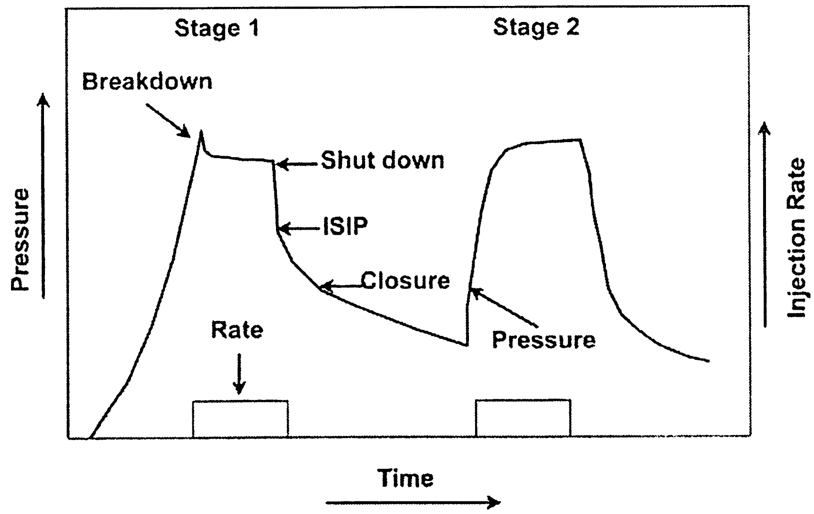
3.7 Well tests

3.71 Injection Tests The only reliable technique for measuring in-situ stress is by pumping fluid into a reservoir, creating a fracture, and measuring the pressure at which the fracture closes. The well tests used to measure the minimum principal stress are in-situ stress tests, step-rate/flow back tests, minifracture tests, and step-down tests. For most fracture treatments, mini fracture tests and step-down tests are pumped ahead of the main fracture treatment. As such, accurate data are normally available to calibrate and interpret the pressures measured during a fracture treatment. In-situ stress tests and step-rate/flowback tests are not run on every well; however, it is common to run such tests in new fields or new reservoirs to help develop the correlations required to optimize fracture treatments for subsequent wells.

3.72 In-Situ Stress Tests. An in-situ stress test can be either an injection-falloff test or an injection flowback test. The in-situ stress test is conducted with small volumes of fluid (a few barrels) and injected at a low injection rate (tens of gal/min), normally with straddle packers to minimize wellbore storage effects, into a small number of perforations (1 to 2 ft). The objective is to pump a thin fluid (water or nitrogen) at a rate just sufficient to create a small fracture. Once the fracture is open, the pumps are shut down, and the pressure is recorded and analyzed to determine when the fracture closes. Thus, the term "fracture-closure pressure" is synonymous with minimum in-situ stress and minimum horizontal stress. When the pressure in the fracture is greater than the fracture-closure pressure, the fracture is open. When the pressure in the fracture is less than the fracture-closure pressure, the fracture is closed. Multiple tests are conducted to ensure repeatability. The data from any one of the injection-falloff tests can be analyzed to determine when the fracture closes.

3.73 Minifracture Tests. Minifracture tests are run to reconfirm the value of in-situ stress in the pay zone and to estimate the fluid-loss properties of the fracture fluid. A minifracture test is run with fluid similar to the fracture fluid that will be used in the main treatment. Several hundred barrels of fracturing fluid are pumped at fracturing rates. The purpose of the injection is to create a fracture that will be of similar height to the one created during the main fracture treatment. After the minifracture has been created, the pumps are shut down, and the pressure decline is monitored. The pressure decline can be used to estimate the fracture-closure pressure and the total fluid leakoff coefficient. Data from minifracture treatments can be used to alter the design of the main fracture treatment, if required.

3.74 Step-Down Tests. For any injection-falloff test to be conducted successfully, a clean connection between the wellbore and the created fracture is needed. The main objective of an in-situ stress test and the minifracture test is to determine the pressure in the fracture when the fracture is open and the pressure when the fracture is closed. If there is excess pressure drop near the wellbore because of poor connectivity between the wellbore and the fracture, the interpretation of in-situ stress test data can be difficult. In naturally fractured or highly cleated formations, multiple fractures that follow tortuous paths are often created during injection tests.



When these tortuous paths are created, the pressure drop in the "near-wellbore" region can be very high, which complicates the analyses of the pressure falloff data. To determine the cause of near-wellbore pressure drop, step-down tests are run.

$$p_{pfr} = \frac{0.2369 i_{pf}^2 \rho}{d_{pf}^4 \alpha^2}.$$

If the near-wellbore pressure drop is caused by tortuosity, then the near-wellbore pressure drop will be a function of the injection rate raised to a power of one-half (0.5), as Eq. shows.

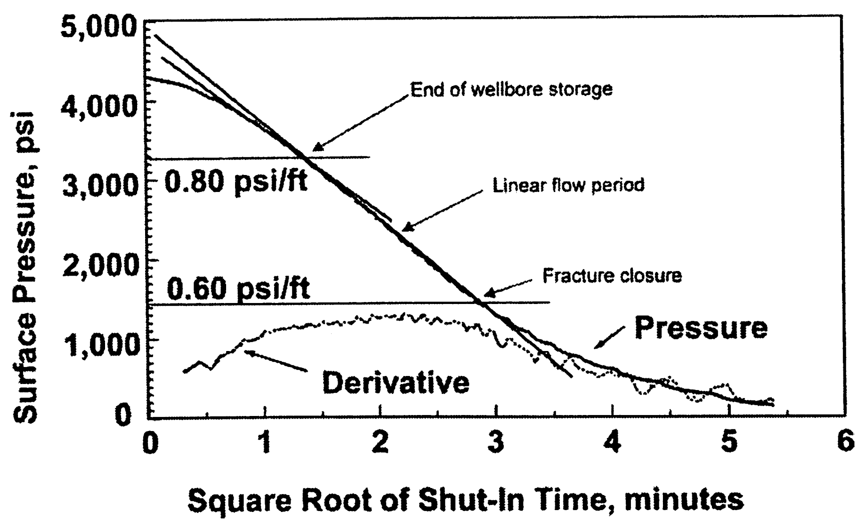
$$\Delta p_T = a \times Q^{0.5}$$

A graph of the value of near-wellbore pressure drop vs. injection rate will provide a clear indication of what is causing the near-wellbore pressure drop. graph of pressure drop vs. injection rate will be concave upward when the pressure drop is dominated by tortuosity and will be concave downward when the pressure drop is dominated by perforation friction.

3.8 Net Pressure. The reason for computing values of in-situ stress and conducting stress tests, minifracture tests, and step-down tests is to compute the net pressure in the fracture. The net pressure is the difference between the actual pressure in the fracture and the minimum in-situ stress,

$$p_n = p_f - \sigma_{min}$$

σmin increases near the tip of the fracture as propagation occurs. The net pressure profile controls both the racture height and fracture width distribution along the fracture length. The value of net pressure is important because the engineer needs to know for which value to design the main fracture treatment, to perform onsite analyses of the fracturing pressures, and to perform postfracture analyses of the fracturing pressures. One of the best methods to analyze a fracture treatment is to use a fracture propagation model to analyze the net pressures measured during a fracture treatment.



Chapter 4

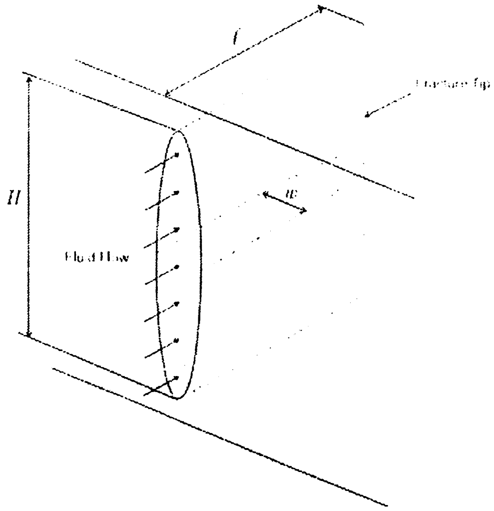
4.1 Hydraulic Fracturing Models

The first fracture treatments were pumped just to see if a fracture could be created and if sand could be pumped into the fracture. In 1955, Howard and Fast 15 published the first mathematical model that an engineer could use to design a fracture treatment. The Howard and Fast model assumed the fracture width was constant everywhere, allowing the engineer to compute fracture area based upon fracture fluid leakoff characteristics of the formation and the fracturing fluid.

4.1 1 2D Fracture Propagation Models

The Howard and Fast model was a two-dimensional (2D) model. When using a 2D model, the engineer fixes one of the dimensions (normally the fracture height), then calculates the width and length of the fracture. With experience and accurate data sets, 2D models can be used with confidence because the design engineer can accurately estimate the created fracture height beforehand. **Figs.** Shows two of the most common 2D models used in fracture treatment design. The PKN geometry is normally used when the fracture length is much greater than the fracture height, while the KGD geometry is used if fracture height and length are similar.

The design engineer must always compare actual results with the predictions from model calculations. By "calibrating" the 2D model with field results, the 2D models can be used to make design changes and improve the success of stimulation treatments. If the correct value of fracture height is used in a 2D model, the model will give reasonable estimates of created fracture length and width, provided, of course, that other parameters, such as in-situ stress, Young's modulus, formation permeability and total leakoff coefficient are also entered correctly. It is desirable to use 2D models for years due to the lack of computing power. Today, with high-powered computers available, Pseudo 3Dimensional (P3D) models are used . P3D models are better than 2D models for most situations because the P3D model computes the fracture height, width and length distribution using the data for the pay zone and all the rock layers above and below the perforated interval.



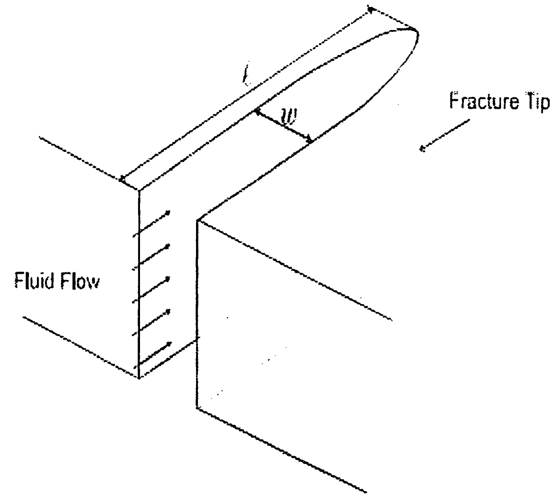


Fig. Schematic showing PKN fracture geometry Fig Schematic showing KGD fracture geometry.

4.1 2 3D Fracture Propagation Models

Clifton provides a detailed explanation of how 3-Dimensional fracture propagation theory is used to derive equations for programming 3D models, as well as P3D models. Fig. illustrates typical results from a P3D model. P3D models give more realistic estimates of fracture geometry and dimensions, which can lead to better designs and better wells. P3D models are used to compute the shape of the hydraulic fracture as well as the dimensions.

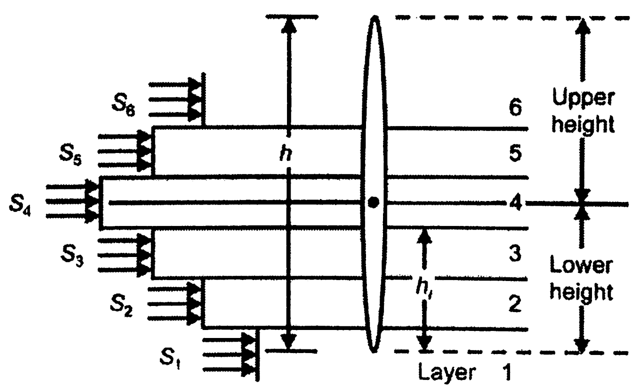


Fig. Width and height from a P3D model.

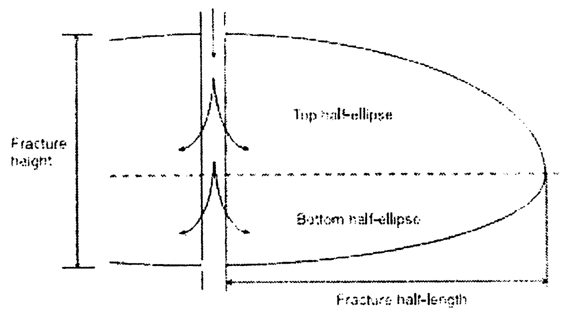


Fig .fracture geometry based on pseudo 3D

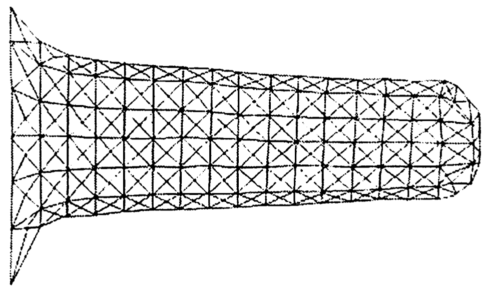


Fig. planar 3D fracture geometry

4.2 Design Objectives

Historically, the emphasis in fracturing low-permeability reservoirs was on the productive fracture length xf. For higher permeability reservoirs, the conductivity kfw is equally or more important, and the two are balanced by the formation permeability k. This critical balance was first discussed by Prats, more than 10 years after the introduction of fracturing, with the important concept of dimensionless fracture conductivity CfD:

$$C_{fD} = \frac{k_f w}{k x_f}.$$

This dimensionless conductivity is the ratio of the ability of the fracture to carry flow divided by the ability of the formation to feed the fracture. Generally, these two production characteristics should be in balance. In fact, for a fixed volume of proppant, maximum production is achieved for a value of CfD between 1 and 2, with an analogy to highway design. Prats also introduced another critical concept, the idea of the effective wellbore radius rw′. A simple balancing of flow areas between a wellbore and a fracture gives the equivalent value of rw′ for a propped fracture .

$$r_w' \approx \frac{2}{\pi} x_f .$$

However, this simple flow area equivalence ignores the altered pore pressure field around a linear transient flow. For pseudoradial flow. Cinco-Ley expressed rw′ as a function of length and CfD. The chart in **Fig.** (equivalent to Prats) can be used (when pseudoradial flow is appropriate) as a powerful reservoir engineering tool to assess possible postfracture productivity benefits from propped fracturing. For example, the folds of increase (FOI) for steady-state flow can be defined as the post-fracture increase in well productivity compared with prefracture productivity calculated from

$$FOI = \frac{\ln\left(r_e / r_w\right) + s}{\ln\left(r_e / r_w'\right)},$$

where re is the well drainage or reservoir radius, rw is the normal wellbore radius, and s is any prefrac ture skin effect resulting from wellbore damage, scale buildup, etc. An equivalent skin effect sf resulting from a fracture is

$$s_f = -\ln\left(r_w' / r_w\right)$$

for use in reservoir models or other productivity calculations. above Equation provides the long-term FOI. Many wells, particularly in low-permeability reservoirs, may exhibit much higher (but declining) early time, transient FOI. The preceding relations are for transient pseudo radial flow before any reservoir boundary effects.

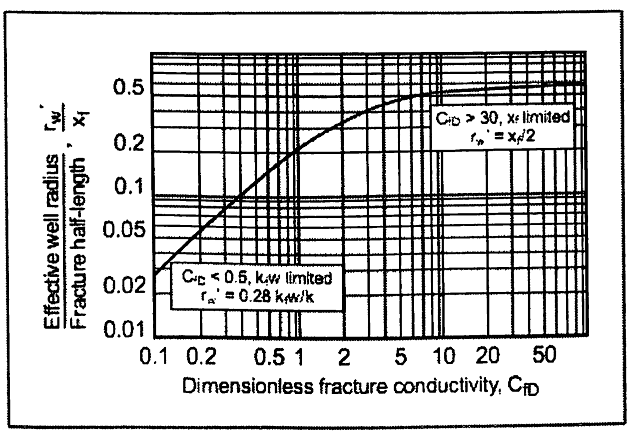


Fig Equivalent wellbore radius as a function of dimensionless fracture conductivity and fracture length.

Rock and Fluid Mechanics

Rock and fluid mechanics (along with fluid loss) considerations control the created fracture dimensions and geometry (i.e., fracture height hf, length L and width w). These considerations all revolve around the net pressure Pnet. However, Pnet, which controls hf and L, is itself a function of hf and L, and the various physical behaviors connecting height, net pressure, width, etc., interact in many ways. This makes simple statements about the relative importance of variables difficult or impossible. However, the basic physical phenomena controlling fracture growth are understood and are well established.

4.3 Material balance

The major equation for fracturing is material balance. This simply says that during pumping a certain volume is pumped into the earth, some part of that is lost to the formation during pumping, and the remainder creates fracture volume (length, width and height). It is the role of fracture models to predict how the volume is divided among these three dimensions. The volume pumped is simply

$$V_i = q_i \times t_p,$$

Where qi is the total injection rate and tp is the pumping time for a treatment. Equally simple, the fracture volume created during a treatment can be idealized as

$$V_f = h_f \times \overline{w} \times 2L = \eta \times V_i,$$

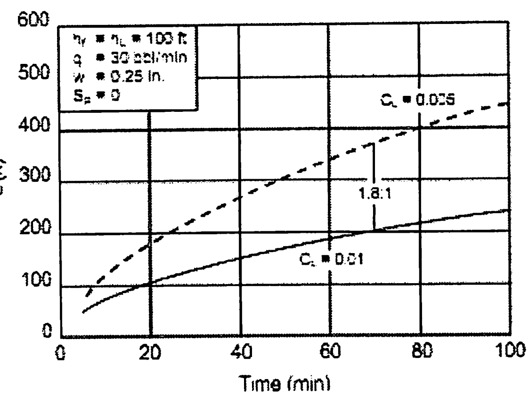
where hf is an average, gross fracture height, w is the average fracture width, L is the fracture half-length or penetration, and η is the fluid efficiency. Finally, as discussed by Harrington et al. and Nolte, the volume lost while a hydraulic fracture treatment is being pumped can be approximated by

$$V_{Lp} \cong 6C_L h_L L \sqrt{t_p} + 4Lh_L S_p,$$

where CL is the fluid-loss coefficient (typically from 0.0005 to 0.05 ft /min1/2), hL is the permeable or fluid-loss height, and Sp is the spurt loss (typically from 0 to 50 gal/100 ft 2). Because material balance must be conserved, Vi must equal VLp plus Vf, and Eqs.can be rearranged to yield showing a general relation between several important fracture variables and design goals

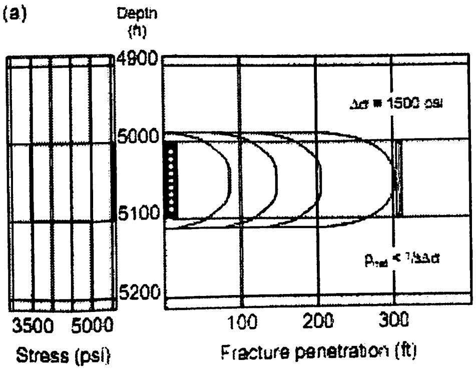
$$L \cong \frac{q_i t_p}{6C_L h_L \sqrt{t_p} + 4h_L S_p + 2\bar{w}h_f},$$

4.4 Fracture height



Equation demonstrates that fracture height hf and fluid-loss height hL are important parameters for fracture design. Loss height is controlled by in-situ variations of porosity and permeability. Fracture height is controlled by the in-situ stresses, in particular by differences in the magnitude or level of stress between various geologic layers. Height is controlled by the ratio of net pressure to stress differences Δσ, as shown in Fig., where Δσ is the difference between stress in the boundary shales and stress in the pay zone. Ignoring any pressure drop caused by vertical fluid flow, the relation among fracture height, initial fracture height, pnet and Δσ can be calculated as demonstrated by Simonson This relation is included in Fig .

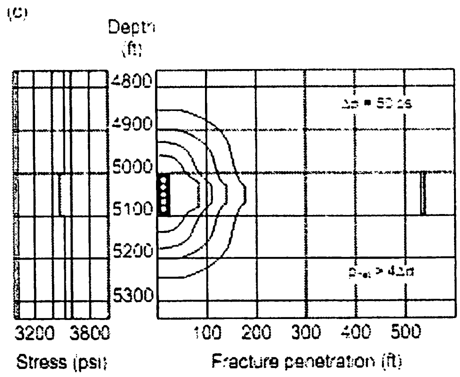
(a)



For cases when pnet is relatively small compared with the existing stress differences (e.g., less than 50% of Δσ), there is little vertical fracture growth and the hydraulic fracture is essentially perfectly confined. This gives a simple fracture geometry and increasing net pressure.

For cases when pnet is much larger than the existing stress differences, vertical fracture height growth is essentially unrestrained. Again, the geometry is a fairly simple radial or circular fracture and declining net pressure.

For more complex cases when pnet is about equal to Δσ, fracture geometry becomes more difficult to predict, and significant increases in height can occur for small changes in net pressure. for this case, the viscous pressure drop from vertical flow retards fracture height growth, and the equilibrium height calculations in Fig. are no longer applicable.



4.5 Fracture width

Consider a slit in an infinite elastic media (i.e., the earth). Also consider that the slit is held closed by a racture closure stress but is being opened by an internal pressure equal to the closure stress plus a net pressure pnet. Under these conditions the slit opens into an elliptical shape, with a maximum width.

$$w_{max} = \frac{2p_{net}d}{E'},$$

where E′ is the plane strain modulus (E′ = E/(1 –v2), v is Poisson's ratio and typically equals about 0.2), and d is the least dimension of the fracture. For a confined-height fracture with a tip-to-tip length greater than hf, d equals hf. This shows a direct relation between net pressure and width and introduces an important material property, the plane strain modulus. However, because typically v2 < 0.1, the plane strain modulus seldom differs from Young's modulus E by a significant amount.

4.6 Fluid mechanics and fluid flow

The major fluid flow parameters are the fluid viscosity μ and injection rate qi. The rate also effects the pump time and hence is important to fluid-loss and material-balance considerations, as discussed previously. Both parameters are critical for proppant transport, and both parameters also affect net pressure and thus affect fracture height and width.

As example, consider a Newtonian fluid flowing laterally through a narrow, vertical slit. For laminar flow, the pressure drop along some length Δx of the slit is

$$\frac{\Delta p_{net}}{\Delta x} = \frac{12\mu q}{h_f w^3}.$$

Assuming a simple case of a long, constant-height and -width fracture with two wings and zero fluid loss (i.e., the flow rate in each wing is q = qi /2) and also assuming zero net pressure at the fracture tip, relationship for fracture width can also be used

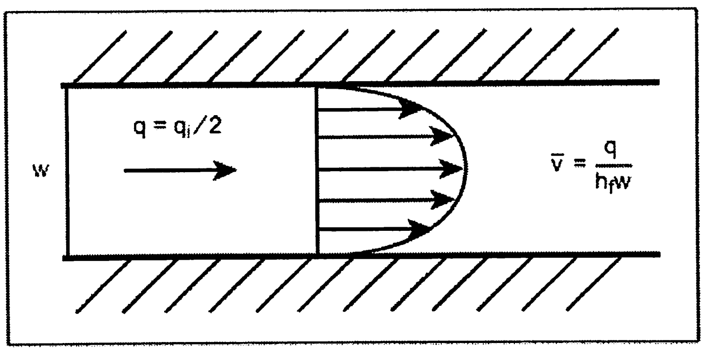


Fig . Fluid flowing laterally through a narrow vertical fracture.

$$p_{net} = \frac{E'^{3/4}}{h_f}\{\kappa\mu q_i L\}^{1/4},$$

where κ is a constant to provide an equality for this expression. Thus, as a result of viscous forces alone, net pressure inside the fracture develops as a function of the modulus, height and (qμ)1/4. From the nature of this relation, however, it is clear that modulus and height are much more important in controlling net pressure than are pump rate and viscosity, the effect of which is muted by the small exponent for the relation.

4.7 Fracture mechanics and fracture tip effects

The fluid mechanics relations show pnet related to modulus, height, fluid viscosity and pump rate. However, in some cases, field observations have shown net pressure to be greater than predicted by Eq.. In such cases the fluid viscosity has a smaller effect on fracture . this is probably because the simple relation in Eq. assumes no net pressure at the fracture tip; i.e., fracture tip effects or fracture propagation effects are ignored. When tip effects are taken into account, the fracture width is affected by both fluid viscosity and tip effect. For a positive tip pressure, the net pressure equation becomes

$$p_{net} \approx \left[\frac{E'^3}{h_f^4} \{ \kappa \mu q_i L \} + p_{tip}^4 \right]^{1/4},$$

where ptip is the pressure required at the fracture tip to open new fracture area and keep the fracture propagating forward.

This simple relationship serves to illustrate that there are always two components to net pressure: a viscous component and a fracture tip effects component. The relative magnitude of the two effects varies from case to case, and because of the small exponent, the combined effects are much less than the direct sum of the individual effects. For example, when the viscous component and the tip component are equal, the net pressure is increased by only 20% over that predicted when one of the com ponents is ignored.

Fracture toughness and elastic fracture mechanics The fracture tip propagation pressure, or fracture tip effect, is generally assumed to follow the physics of elastic fracture mechanics. In that case, the magnitude of the tip extension pressure ptip is controlled by the critical stress intensity factor KIc (also called the fracture toughness).

On the other hand, modeling clay has low strength, but the presence of a flaw or fracture does not significantly reduce the strength. From elastic fracture mechanics, for a simple radial or circular fracture geometry with a pene tration of L, the fracture tip extension pressure is and it decreases as the fracture extends. For even a small fracture penetration of 25 ft, this gives a tip extension pressure of 29 psi, whereas viscous pressures are typically 10 or more times larger.

4.8 Apparent Fracture Toughness

Field data typically show fracture extension pressure to be greater than that given by Eq. with 100 to 300 psi as typical values and even higher values possible. This difference is due to several behaviors not included in elastic fracture mechanics calculations. One important (and long-recognized) consideration is that the fracturing fluid never quite reaches the fracture tip; i.e.. thereis a "fluid lag" region at the tip that increases the apparent toughness and tip pressure. In other cases, tip pressure may be even greater. Other tip phenomena include nonelastic rock deformation near the fracture tip and tip plugging with fines, with these mechanisms acting alone or in conjunction with the fluid flow and/or fluid lag phenomena.

Measured values for tip extension pressure that are higher than predicted from laboratory measured rock toughness KIc can be accounted for in hydraulic fracture calculations through the use of the effective, or apparent, fracture toughness KIc-apparent. In practice,because KIc-apparent is not a material constant, the tip effects should be defined or calibrated by fracturing pressure data for a particular situation.

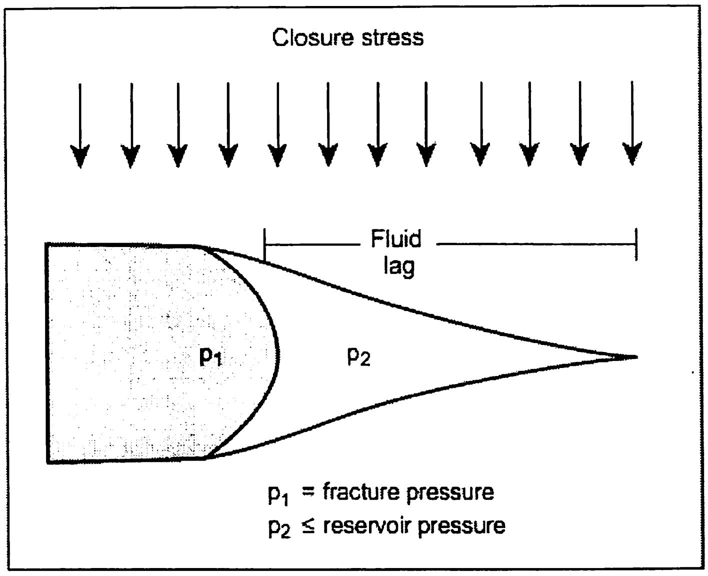


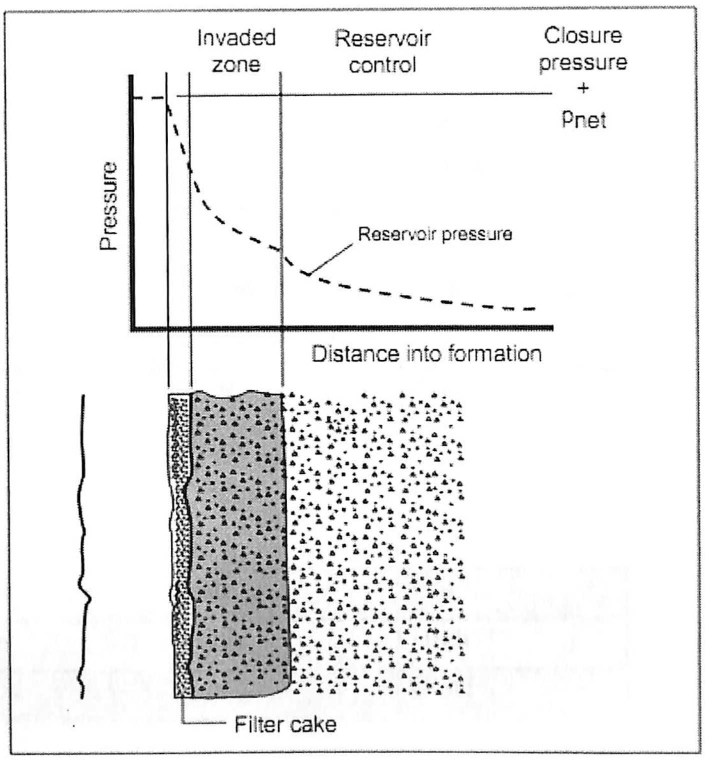
Fig. Unwetted fracture tip (fluid lag).

4.9 Fluid loss

As seen from the material balance, fluid loss is a major fracture design variable characterized by a fluid-loss coefficient CL and a spurt-loss coefficient Sp. Spurt loss occurs only for wall-building fluids and only until the filter cake is developed. For most hydraulic fracturing cases, the lateral (and vertical) extent of the fracture is much greater than the invasion depth (perpendicular to the planar fracture) of fluid loss into the formation. In these cases, the behavior of the fluid loss into the formation is linear (1D) flow, and the rate of fluid flow for linear flow behavior is represented by Equations.

The first mechanism is the wall-building characteristics of the fracturing fluid, defined by the wall building coefficient Cw. This is a fluid property that helps control fluid loss in many cases. For most fracturing fluid systems, in many formations as fluid loss occurs into the formation, some of the additives and chemicals in the fluid system remain trapped on or near the formation face, forming a physical filter -cake barrier that resists fluid loss.

Outside of the filter cake is the invaded zone, which is the small portion of the formation that has been invaded by the fracturing fluid filtrate. This mechanism is the filtrate effect, or invaded zone effect, and it is characterized by the viscosity or relative permeability control coefficient Cv. As Cv can be calculated, and this parameter is governed by the relative permeability of the formation to the fracturing fluid filtrate kfil, the pressure difference Δp between the pressure inside the fracture (i.e., closure pressure + Pnet) and the reservoir pressure, and the viscosity of the fracturing fluid filtrate μfil.. Other cases are where a clean fluid is used such that no filter cake develops or for fracturing high-permeability wells where no filter cake develops and high-viscosity crosslinked gel may be lost to the formation (i.e., μfil is very high).



5.1 Types of Fracturing Fluids for Coal

For methane production rates to be economical, permeability of the formation must be adequate. Permeability of the coalseam depends on the natural fracture system and the connection of the fracture system to the wellbore. Connecting the fissures to the wellbore must be by hydraulic fracturing or by regionally limited cavity completions. There has been uncertainty in the industry on the choice of the proper fracturing fluid—whether to use linear polymer, cross linked gel, water with proppant, water without proppant, or nitrogen foam.

The history of changing popularity of each of the preceding fluids reflects the uncertainty. Cost, formation damage, proppant placement, and propped fracture length dictate the choice. Table below summarizes the general attributes of the fluid selections, and it is surmised from the tabulation that either crosslinked gels or nitrogen foams would be preferred.

	Cost	Formation Damage	Propant Displacement	Propped Length
Water w/o proppant	Good	Good	Poor	Poor
Water w/ proppant	Good	Good	Poor	Poor
Linear Gel	Fair	Poor	Fair	Fair
Crossinked gel	Fair	Poor	High	HIgh
Nitrogen foam	High	Good	Good	Good

5.2 Cross linked Gels

In the many CBM wells that have been fractured in the San Juan basin. the fracturing fluid most frequently used has been a 30–35 lb per 1,000 gal HPG in 2% KCl water solution cross linked with the borate ion. Polymer content of the gel is minimized to reduce residual unbroken gel, cost, and additional produced-water treatment requirements to meet BOD specifications. The water-soluble HPG polymer is derived from guar by combining it with propylene oxide to achieve a polymer with less residue and higher temperature stability. The structure of HPG is presented in Fig. It contains one galactose unit to two mannose units as the basic repetitive group of the polymer chain.

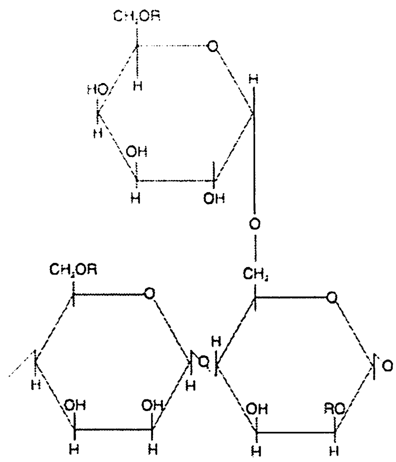


Fig HPG Structure

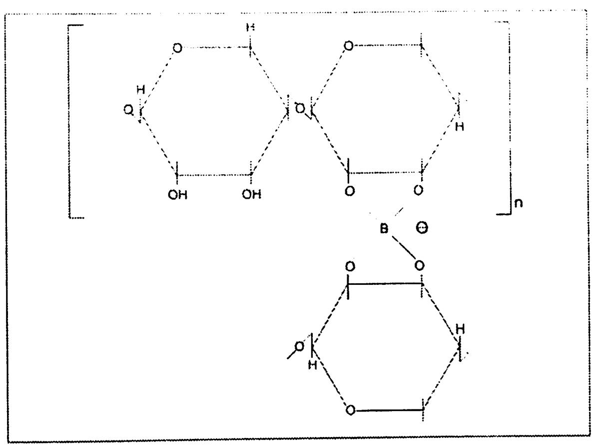


Fig HPG crosslinked with Borate

Crosslinking increases viscosity of the fluid with a minimum amount of polymer. The borate ion's most commonly used as the crosslinker in CBM fracturing fluids. It links the polymer as shown in Fig. above.

The gel is shear thinning but reforms its structure with the borate ion crosslinker, making it easy to work with in the field. Apparent viscosity of the borate-crosslinked gel is high, and it provides excellent proppant transport. At the temperatures encountered in CBM wells, structures of the gel are stable and thus provide the viscosity needed for sand transport. San Juan basin temperatures of 105 to 120°F are in ranges that provide good proppant transport by fracturing fluids.

The relationship of apparent viscosity to temperature for one HPG gel with borate crosslinker is given in Equation Note that the apparent viscosity of HPG without crosslinker follows the relationship with temperature of Eq. The gel's apparent viscosity is much higher, but its viscosity decreases at the same rate as the polymer solution at temperatures encountered in CBM wells; the gel viscosity declines with temperature according to Eq..

$$\mu_a = \beta \, e^{\alpha/T}$$

μa = apparent viscosity

ß , α = constants

T = absolute temperature

Higher temperatures above those encountered in CBM wells break the gel abruptly, and its viscosity declines to that of the base polymer solution.

Fracturing with gels maximizes the fracture length and increases proppant loading over longer distances. Good results have been reported in the San Juan basin. HPG polymers crosslinked with the borate ion as 30–35 lb of polymer per thousand gallons of solution are commonly used; less than 10 lb/gal of 20/40-mesh sand is common.

When compared to water as the fracturing fluid, crosslinked polymers have four possible disadvantages.

1. The cost is higher.

2. Chemicals in the gelled fluid may alter the surface properties of the coal.

3. The polymer or gel may plug flow channels. Gel may penetrate into the coal 50 ft from the vertical fracture and be trapped upon closure.

4. Breakers added to the gel may be inadequate and leave unbroken gel in seams.

5.3 Water

Water has been used as the ultimate cheap, non damaging fracturing fluid but with the major deficiency of reduced sand transport. Less than 5 lb/gal of a 12/20-sand has been used. Fracturing with water in coalbeds may pump only 1–1.5 lb/gal of sand without screenout; if the water flow rate is increased to carry more sand, the height of the fracture may grow. Excessive height growth of the fracture in and/water fracturing increases the problem of sand settling from the water. Propping a limited portion of the fracture is indicated in Fig. from a simulation run by Amoco6 to match the results of fracturing the Black Creek group in Alabama with water-carrying sand. Possibly, only one-third of the seams in the group were propped by the sand.

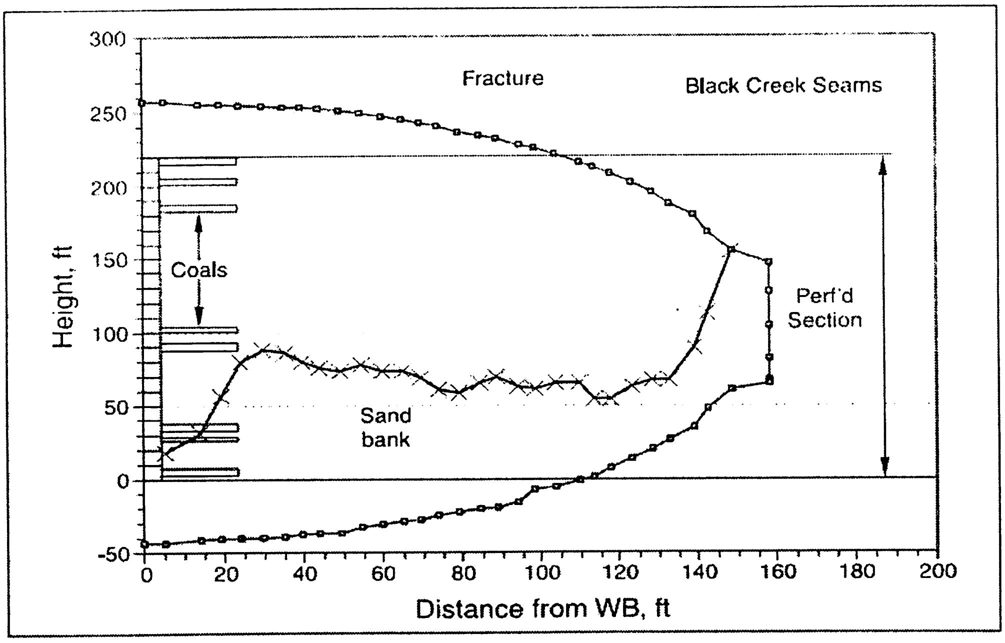


Fig Schematic of proppant distribution in water fracture

If in-situ shear stresses cause slippage at the interface during fracturing, the rugosity of the faces may provide a propped fracture. Some successes with water fracturing in thin, multiple seams have been seen. It is possible that water fracturing without sand creates fractures of less width and less stress redistribution. These restricted widths may close face cleats parallel to them less than wider fractures propped with sand, where closing of the parallel face cleats would divert gas flow to the less permeable butt cleats.

5.4 Comparison of Gel and Water

A field study in the of basins compared water fracturing with gelled-fluid fracturing under controlled conditions. Twenty-three wells were fractured, with water-soluble cross linked polymer and 10 with water. The selected wells were interspersed to avoid bias of location. Characteristics of the water and water-gel treatments are compared in Table. The tabulation shows approximately a 50% cost saving from the water-fracturing treatment, but the gel fluid transported more than twice as much proppant. The coals were of good permeability and boreholes were cased and perforated as indicated in Table. After 12 months of production, the water-fractured wells had 20% more methane production with less formation water production.

Characteristic	Water	Gel
Chemicals	No polymer	Borate crosslink, HPG, 30 lb/1,000 gal
Proppant	<5 lb/gal 12/20 70,000 lb/zone	10 ppg 12/20, 100,000 lb/zone
Flow rate, bbl/min	50 to 60	40
Number of wells	10 Oak Grove	13 Oak Grove
Production	12 months	12 months
Cost, USD	$28,000	$50,000
Efficiency, %	<20	50 to 80

Table :Comparison of Water and Gel Fractures

The comparison was broadened to include the results from additional fracturing fluids in the San Juan basin as well as the Warrior basin. Sandless water fractures, water with sand fractures, crosslinked gel fractures, sandless water refractures, and cavity completions were compared.

Basin	X	Y	Gas Production X/Y	Stimulation Cost X/Y
San Juan	Cavity	Gel	5 to 10	11.0
San Juan	WFS	Gel	2.5	0.5
Black Warrior (Oak Grove)	WFS	Gel	1.2 to 1.4	0.5
Black Warrior (Oak Grove)	WFS	SWF	1.9	2.0
Black Warrior	SWF refracture	Gel original fracture	2.0	0.25

Table :Comparisons of Stimulation Treatments

The results indicate a cost savings with the water, formation damage with gels, and a need for proppant support of the fracture. A special case is indicated in the San Juan basin where a good permeability and cleat system are sensitive to formation damage.

5.5 Foam

Nitrogen foam is a gas-in-water emulsion made stable by the addition of a surfactant and a viscosifying agent, such as HEC or HPG. The quality of the foam, or volume percentage of nitrogen in the foam, may range from 60–90%. Nitrogen foam reduces formation damaging effects of the fracturing fluid for the following reasons:

- The nitrogen provides energy to clean the fracturing fluid from the formation.
- The foam requires about 70% less water than a gel.
- HEC is used at reduced levels and is a less damaging viscosifier.
- Foam has better leakoff characteristics.

In addition to assisting fluid cleanup, the nitrogen released from the foam acts to enhance methane desorption and production. The mechanism is to reduce partial pressure of methane in the coal, thereby creating a concentration gradient for diffusion of methane from the micropores. Nitrogen does not cause appreciable swelling of the coal because it is less readily adsorbed than the methane. Carbon dioxide, if used in the foam, could induce detrimental matrix swelling because it is preferentially adsorbed by the coal.

Advantages of nitrogen foam as a fracturing fluid may be summarized as follows:

- Cleans up quickly from the induced fracture.
- Leaves virtually no unbroken fluid.
- Leaves a minimum residue to plug the reservoir.
- Inflicts minimum damage to coal.
- Enhances CH_4 desorption by lowering CH_4 partial pressure.
- Provides good proppant transport.
- Reduces leakoff.

The **Disadvantages** of a foam fracturing fluid for coals are as follows:

• More expensive.

• More difficult quality control.

• Difficult to characterize rheologically.

A laboratory analysis of permeability damage to Warrior basin coal (Blue Creek seam) from flow contact with a 70% nitrogen foam showed a high recovery of permeability after the test. The continuous phase of the foam was 2% KCl in water, viscosified with HEC polymer as 30 lb of polymer per 1,000 gal of liquid. The results in Fig. illustrate the non damaging aspects of N2 foam fracturing fluids, 33 as 78% of the permeability had been recovered shortly after foam treatment, and improvement was continuing at that time. Although more expensive than HPG, the HEC polymer is less damaging to the formation.

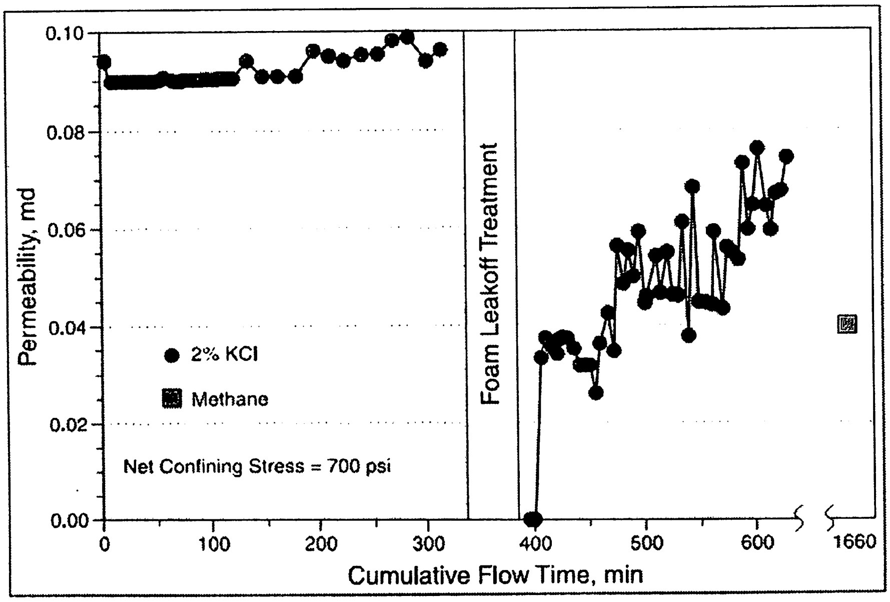


Fig Non damaging aspects of foam

5.6 Proppant Considerations

Sand proppant has sufficient strength for CBM applications, so it is the economical and practical choice. Some common problems encountered in conventional fracturing involving proppant are magnified in coalbed fracturing:

(1) embedment of proppant into the matrix of the soft formation

(2) trapping of large volumes of fines by the proppant

(3) leakoff of the sand-bearing fluid into secondary fissures and cleats,

(4) transport of the proppant through a tortuous path

Because of the soft, elastic properties of coal, proppant embeds in the coal matrix to reduce conductivity. In doing so, it causes spalling of the fracture face. Consequently, the coal chips that collect in the sandpack further contribute to the deterioration of fracture conductivity. As described by Eq the initial width of the packed sand in the fracture is decreased to eventually give an effective sandpack width, Weff

$$W_{eff} = W_i - \Delta W_c - \Delta W_{emb} - \Delta W_s$$

where

Weff= effective sandpack width

Wi= initial sandpack width

ΔWc = sandpack compression

ΔWemb = sand embedment

ΔWs = sand width loss due to spalling

Hardness of coal, the property affecting embedment, is difficult to measure in the laboratory because of the randomness of fissures and the introduction of fractures from handling of the sample. A general indication of the susceptibility to proppant embedment as a function of coal rank. It is evident Higher loadings of the proppant in the fracture will alleviate the problem.

Three other problems—fines, leakoff, and tortuous path—might be alleviated by proper selection of size distribution for proppant and their schedule of introduction.

5.6 1 Proppants

Proppants are used to hold the walls of the fracture apart to create a conductive path to the wellbore after pumping has stopped and the fracturing fluids has leaked off. Placing the appropriate concentration and type of proppant in the fracture is critical to the success of a hydraulic fracturing treatment. Factors affecting the fracture conductivity are

- proppant composition
- physical properties of the proppant
- proppant-pack permeability
- effects of postclosure polymer concentration in the fracture
- movement of formation fines in the fracture
- long-term degradation of the proppant.

Physical properties of proppants

The physical properties of proppants that have an impact on fracture conductivity are

- proppant strength
- grain size and grain-size distribution
- quantities of fines and impurities
- roundness and sphericity
- proppant density.

To open and propagate a hydraulic fracture, the in-situ stresses must be overcome. After the well is put on production, stress acts to close the fracture and confine the proppant. If the proppant strength is inadequate, the closure stress crushes the proppant, creating fines that reduce the permeability and conductivity of the proppant pack.

Proppant grain roundness is a measure of the relative sharpness of the grain corners, or grain curvature. Particle sphericity is a measure of how close the proppant particle or grain approaches the shape of a sphere. If the grains are round and about the same size, stresses on the proppant are more evenly distributed, resulting in higher loads before grain failure occurs.

Angular grains fail at lower closure stresses, producing fines that reduce fracture conductivity. Proppant density has an influence on proppant transport because the settling rate increases linearly with density. Therefore, high-density proppants are more difficult to suspend in the fracturing fluid and to transport to the top of the fracture. Placement can be improved in two ways: using high-viscosity fluids to reduce settling or increasing the injection rate to reduce treatment time and the required suspension time.

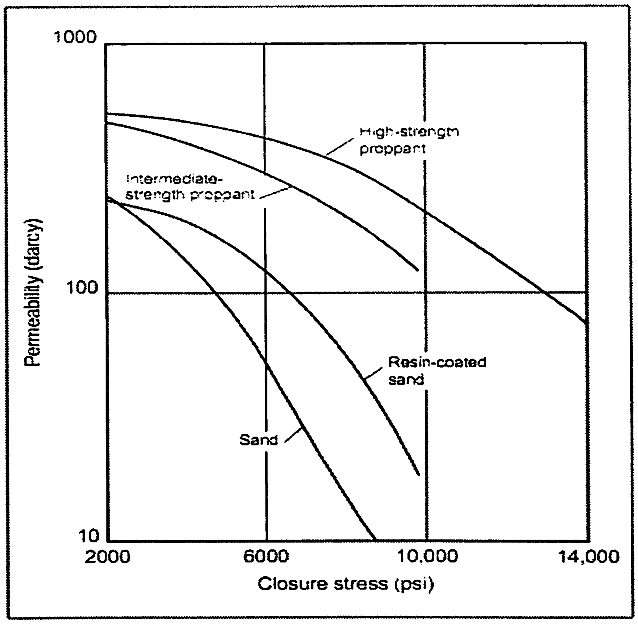


Fig . Strength comparison of various types of proppants.

Unique Problems in Fracturing Coals

Most anomalies in fracturing coals result from uncommon values of properties of the coal reservoir, such as rock mechanical properties and extensive natural fractures in the coals. As a consequence of these coal reservoir properties, induced fractures are very sensitive to complex in-situ stress profiles and the altering of those stresses when drilling and fracturing. Treating pressures may be higher than conventional reservoir fracturing.

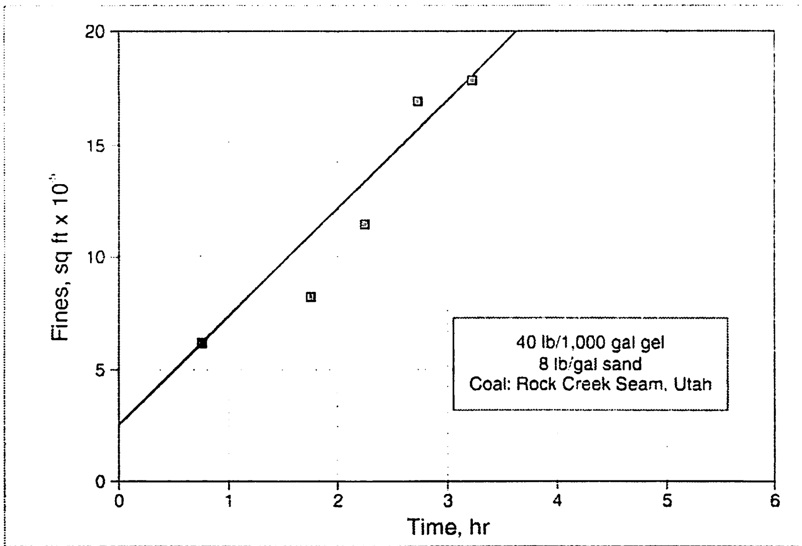
The organic composition of the reservoir rock makes it susceptible to damage. Fluid damage to the coals occurs by two mechanisms. First, the organic surface of the coal is especially susceptible to fluid damage by adsorption of chemicals from the fracturing fluid or drilling fluid. Second, the fluids may become trapped in the intricate fissure network that constitutes the flow path. Perhaps the more pervasive problem is the trapped fluids.

6.1 Fines

Fines contribute to elevated pressures during fracturing. Fines are known to deteriorate fracture conductivity with time, possibly packing into secondary and tertiary natural fractures to damage permeability. Fines could load the fracturing fluid to increase its viscosity and consequently increase pressure drop as the more viscous fluid moves through the fracture. Parting of the coal could create rubble and fines near the wellbore for a more tortuous flow path. The fines could pack in the tips of developing fissures or bridge elsewhere in the fracture to cause higher treating pressures

Laboratory burst-tests verify the generation of fines but in volumes that will not load the fracturing fluid appreciably. More important effects on treating pressures come from fines concentrating near the wellbore to create high pressure drops in the fluids flowing through them. Injection falloff tests in CBM wells that reveal high skin factors are indicative of this.

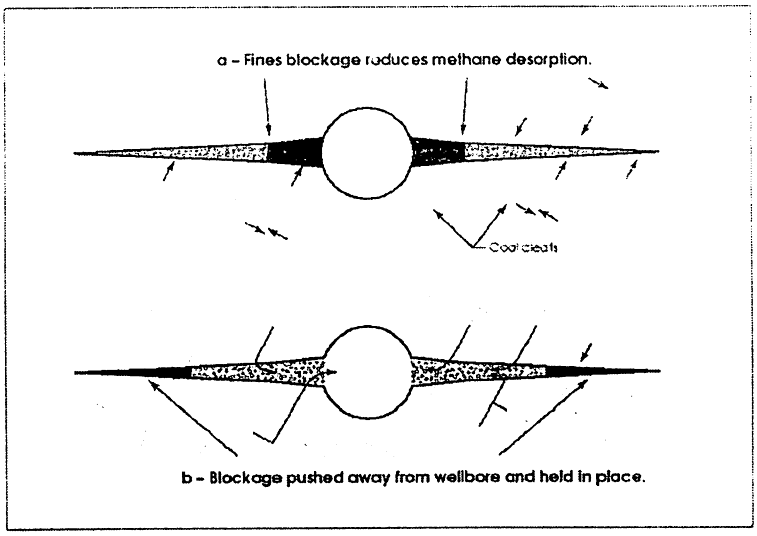
Fines are also created from the attrition of the fracturing fluid, loaded with sand, flowing past the coal surface. A tortuous fluid path causing high-velocity fluid flow, such as near the wellbore or through opened butt or tertiary cleats, would contribute to the attrition of fines. Shear stresses on the coal that move one face of the fracture or cleat relative to the other face would also be expected to generate fines.



Perforating only in the rock partings between seams proved effective at Rock Creek in preventing pump repairs and work-over's, primarily because fewer fines were generated. Since the fracturing fluid loaded with sand increases in abrasiveness with velocity, most damage occurs in the vicinity of the wellbore there the cross-sectional area of the flow channel is smallest and the velocity of the fracturing fluid is greatest.

In the case of thin, multiple seams, perforating in the inorganic rock avoid the high attrition of coal fines near the wellbore. Perforating in an acceptable rock parting may later help remove coal fines entrained with production fluids by screening those fines in the sand-propped fracture of the inorganic rock before they concentrate at the wellbore. In many cases, it is desirable to perforate only the coalseams to avoid directing the hydraulic fracture treatment into a lower-stress sandstone or carbonate.

A post-fracture service that helps remove wellbore damage and coal fines blockage through a powerful backflush has been developed. The mobility of the fines is then restricted with a proprietary chemical formulation that makes the surface of the coal particle "tacky," enabling them to stick together and cling to formation features away from the critical flow paths in the proppant pack. Fig. shows how fines "clots" can accumulate near the wellbore in the pack. The thin carrier fluid is pumped under high pressure into the damaged fractures, helping break down the clots of coal fines and displacing them to the outer limits of the fracture system. The clots are immobilized at the far reaches of the pack, restoring conductivity to the wellbore.



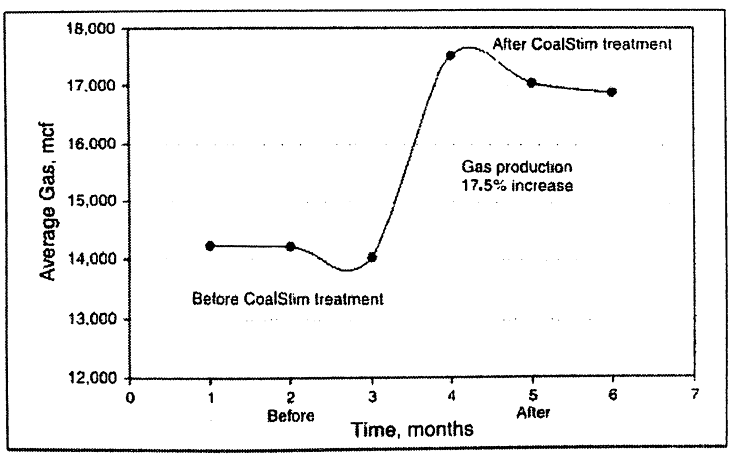


Fig. Production increase from controlling fines

another improvement in fines control is the use of a surface modification agent (SMA) on the surface of the proppant grains during hydraulic fracturing that provides several benefits:

• Helps maintain a high well production rate for a longer period of time.

• Enhances the frac fluid cleanup .

• Reduces proppant settling to help improve permeability of the proppant pack.

• Helps reduce proppant flowback.

• Adds surface modification agent (SMA) on-the-fly to help eliminate leftover coated proppant.

• Stabilizes the proppant pack/formation interface to reduce the intrusion of formation material into the proppant pack.

With the amount of fines generated during a stimulation treatment, a stabilized pack/formation interface is critical to maintaining conductivity through the proppant pack. Intrusion of fines into the pack is the major cause of production decline in a CBM producer. Besides plugging the pack, fines can be the beginning point for scale precipitate formation. Using SMA, the operator can place the rod pump below the lowest perforations, allowing a more efficient de-watering of all coals. All CBM projects can benefit from lowering the pumps to provide lower backpressure on the coals.

6.2 Fluid Damage.

The organic surface of coal has the potential of being damaged from adsorption of ingredients of the fracturing fluid (or drilling fluid) in a manner unlike that of the inorganic surfaces of conventional reservoirs. Adsorption and physical entrapment of polymer molecules in the coal obstructs butt and face cleats, tertiary fissures, and micropore openings to restrict methane desorption, diffusion, and Darcy flow. Molecules small enough to enter the micropores, such as CO2, that are strongly adsorbed in the micropores cause swelling of the coal matrix with attendant permeability reduction. The degree of swelling is dependent upon the affinity of the adsorbate for the solid surface.

A possible problem of chemicals in crosslinked gels altering permeability by matrix swelling from adsorption has been investigated by Puri, et al. 9 Cores of 3.5-in. diameter (from the San Juan basin) and 2.0-in. diameter (from the Warrior basin) were evaluated in the laboratory by Amoco for polymer damage to permeability. The flow tests were structured to isolate permeability damage from sorption effects and to minimize extraneous effects of cleats physically bridging and packing with gel. The gel in the tests had been broken and the fracturing fluid filtered. It was found that

HPG decreased permeability by a factor of 10 in each of the two coals. In Fig., the Fruitland coal exhibits a precipitous decline in permeability simultaneously with the commencing flow of the fracturing fluid. After deterioration of permeability from sorption, permeability could not be reinstated. The damage as mostly irreversible.

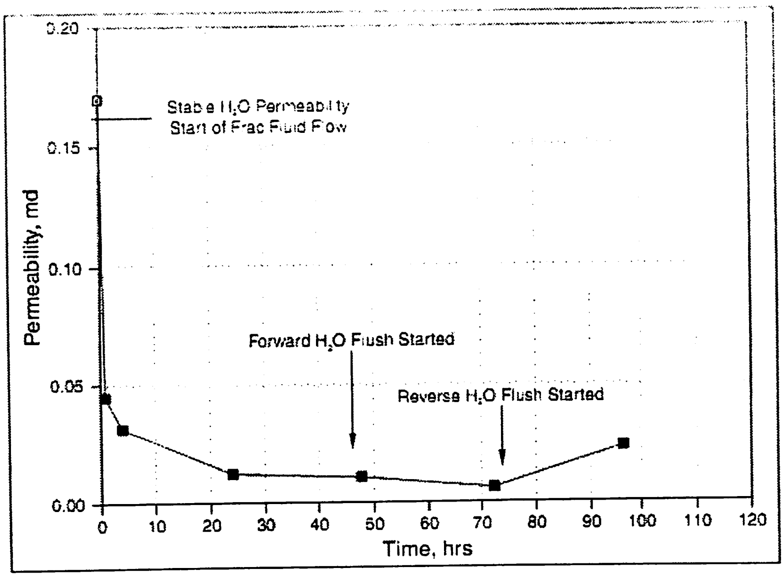


Fig . Gel damage, San Juan core

In Fig., the higher permeability Warrior basin coal demonstrated a similar damage from the broken polymer in the Amoco test. It is recognized that the primary and secondary cleat system as well as the tertiary fissures of coals represent the flow system for future gas production and must be protected during the drilling or completion process. Besides chemical damage of gels to the organic surface, blockage of the natural fractures can occur as high treating pressures open fissures for fluid invasion and as the gels become trapped by closure; filter cakes may not limit fluid invasion as in sandstone formations. Mine back has revealed unbroken gels in fractures far from the wellbore at extended times after treatment. An estimated 25% of the gel remained in the formation in an Oak Grove, Alabama test conducted by Amoco.

It should be emphasized that fracturing with gel fluids has produced many successful wells that are economical and operate with no apparent deleterious effects from the fluid. However, gel damage does often occur, and it can be substantial. At the Rock Creek test site, remedial treatments of poorly performing wells were conducted. The criteria for selecting the wells for corrective action were as follows. The criteria reflect the probability of the original fracturing fluid damaging the coal:

- Original stimulations used guar-based fracturing fluids with an enzyme breaker.

- Fluid returned at high viscosity after fracturing.

- Some wells underachieved in the midst of good performers. The restimulation of Well P3 at Rock Creek is a classic example. HPG gel had been used originally to fracture the well. Production rates from the well were retarded at 65 Mcf/D. The well was refractured with nitrogen foam containing hydroxyethyl cellulose (HEC). After the remedial treatment, production reached 380 Mcf/D ..

6.3 Excessive Treating Pressures

A higher pressure than ordinary may be necessary to initiate a fracture in coal. With normal expectations of overburden pressure gradient of 1.0–1.2 psi/ft and of minimum horizontal stress of 0.6–0.8 psi/ft, the pressure to initiate the fracture should be approximately 100 psi greater than the minimum horizontal stress to create a vertical fracture, 5 or no more than a 1 psi/ft gradient. Instead, a fracture gradient greater than 1.0 psi/ft is often encountered in coals. A survey of the fracturing gradients encountered in the Black Warrior basin of Alabama indicated the distribution as presented in Fig.

It is evident that most of the fracture gradients in the Warrior basin exceed the normal 1.0-psi/ft gradient. Note that some pressures exceeded 2.0 psi/ft. The preponderance of wells were within the 1.0–2.0-psi/ft range. Only about 20% of the wells exhibited gradients less than 1.0 psi/ft

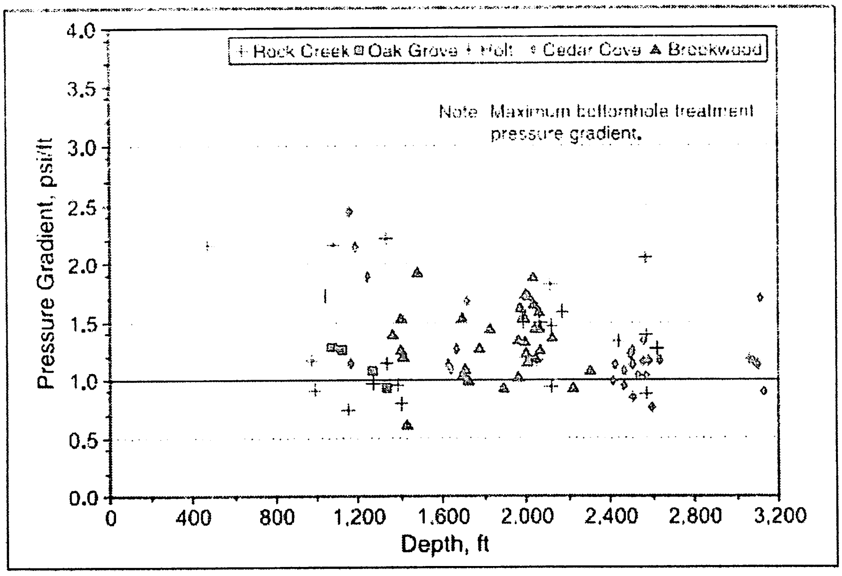


Fig. High fracture gradients in Warrior basin

.The following mechanisms have been postulated to account for the higher than expected fracturing resources in coal:

1. Borehole instability or perforating causes rubble at the point of fracture initiation. Any stress relief of the coals results in breakup of the coal block. Drilling the wellbore, perforating, and even fracturing realign stresses surrounding the borehole. The unconsolidated coal chips retard initiation of the hydraulic fracture.

2. Bursting of the rock at fracture initiation generates fines that bridge the crack near the wellbore. Further from the wellbore, the accumulation of fines and chips blocks the fracturing fluid front, redirecting the path of the fracture.

3. Tortuous fracture path develops as the path follows cleats, slippage at joints occurs, and horizontal components at the rock interface develop. A tortuous path may develop at the wellbore if the perforations are not aligned with the maximum horizontal stress.Otherwise, the fracture may propagate radially until extending in the direction of maximum horizontal stress. The tortuous path causes greater pressure drops in the fluid, requiring higher pressures to open the apertures sufficiently for sand traverse.

4. A network of fractures, multiple fractures, and parallel fractures develops. These have been documented in minethroughs. They tend to divert fracturing fluid, necessitating higher pressures to propagate the primary fracture.

5. Fracture tip anomalies occur from fines at the tip or fluid lag. This is similar to 3, but it occurs at the fracture tip.

6. Raising pore pressures near the wellbore makes the coal subject to failure. The proposed mechanisms causing high fracturing pressures are depicted in Fig. 8.13. The most likely causes of the high fracturing pressures are rubble near the wellbore from poroelastic effects, tortuous path near the wellbore and beyond, and multiple fractures.

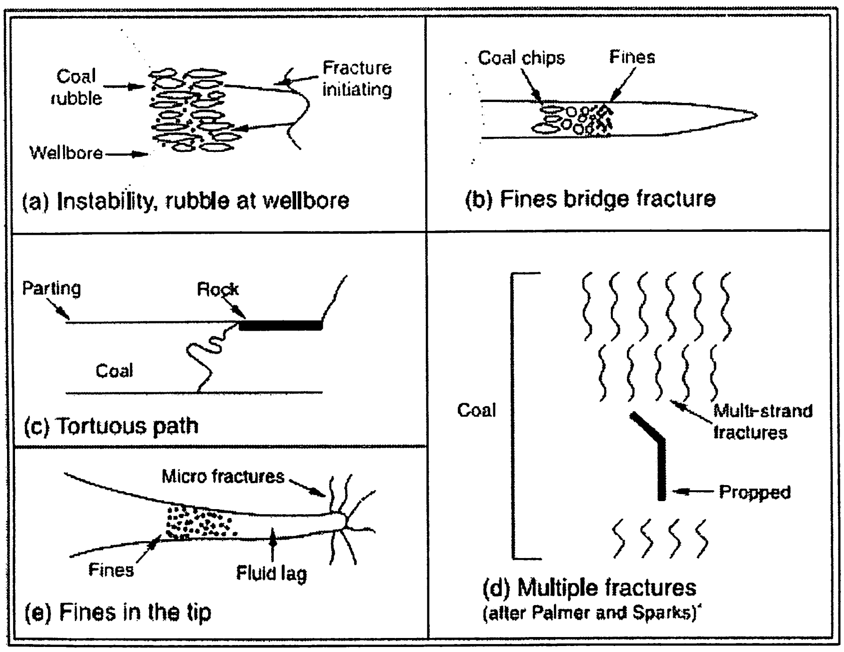


Fig. Mechanisms causing excessive fracturing pressures

Laboratory and simulator uses of field data by Khodaverdian, McLennan, and Jones indicate that coal fragments in the fracture near the wellbore help cause the high pressures. The pressures in the fracture as a function of distance from the wellbore show the effect of near-wellbore damage, as pressures drop off rapidly a short distance from the well.

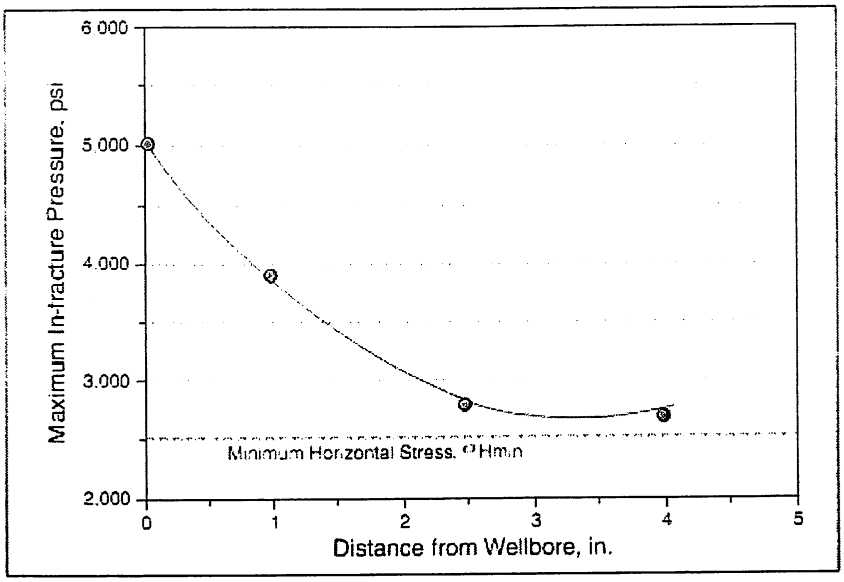


Fig. Near-wellbore damage

Fluid leakoff from the fracturing process increases pore pressure to the extent that mechanical properties of coal deteriorate near the wellbore. Young's modulus decreases and Poisson's ratio increases in such instances, thereby increasing the fines generation and causing the failure of the coal matrix. In the case of multiple, thin seams, perforating below the coalseam or in the parting between seams, if the bounding rock is suitable, reduces coal rubbling from perforations, fines generation from the bursting of the coal at fracture initiation, and attrition of fines from the high velocity of the fluid near the wellbore. It also may avoid degrading poroelastic effects. The five proposed mechanisms presented in Fig. may work in consort or individually. Most have been verified. The amount of the pressure drop due to each mechanism is unknown in the coal fracturing process.

6. 4 Leakoff

Historically, when coalseams were encountered in the hydraulic fracturing of conventional formations, the coal acted as a barrier to fracture growth because of fluid leakoff, elastic properties of the coal, and the likelihood of slippage at the coal-rock interface. With the advent of the CBM process and the objective to penetrate or stay within the bounds of the coal, the problem of leakoff became magnified.

The following deleterious effects result from leakoff in coals:

- Loss of fluid limits penetration of the fracture.
- Fracturing efficiency decreases.
- Formation damage likely occurs.
- Screenout probability increases.

The severity of the leakoff problem in coals is substantiated from mineback observations. For example, cement was observed in a natural fracture in the roof of a coal mine 133 ft from the wellbore at Oak Grove in the Black Warrior basin. In another instance, unbroken gel was spotted in a fracture 7 months after the stimulation was completed.

In a third case of eight field treatments in a government-sponsored test where fluorescent paint was part of the fluid system during fracturing, paint was observed as far as 630 ft from the wellbore in unpropped face and butt cleats. The paint in some intercepted fractures revealed stair-stepped butt and cleat joints propagating through the coal. In extensive natural fracture networks of coals, the pressures imposed during hydraulic fracturing open the fissures to compound the leakoff problem. This factor may be accentuated in the fairway section of the San Juan basin where the rank coal has an elaborate network of cleats, closely spaced, including superposed tertiary cleats from a reoriented stress field. The high-permeability coal in the fairway is more susceptible to leakoff of fracturing fluids upon pressurizing, and greater damage to the coals may result from fracturing with gels.

Penny and Conway addressed the leakoff problem in laboratory experiments with 3.5-in. × 2.9-in. mined coal samples taken from the Fruitland formation of the San Juan basin. Because of the randomness of the cleat system, the permeabilities of the samples ranged from 1 to 100 md with an average value in his tests of 40 md. Although 1-md samples were impermeable to all fracturing fluids, both crosslinked and noncrosslinked HPG fluids moved into the natural fractures of the 40-md samples unhindered by any filter-cake buildup at modest driving pressure differentials . Note that no filter cake develops to obstruct leakoff at any pressure. At the higher pressures, loss of fluid increased.

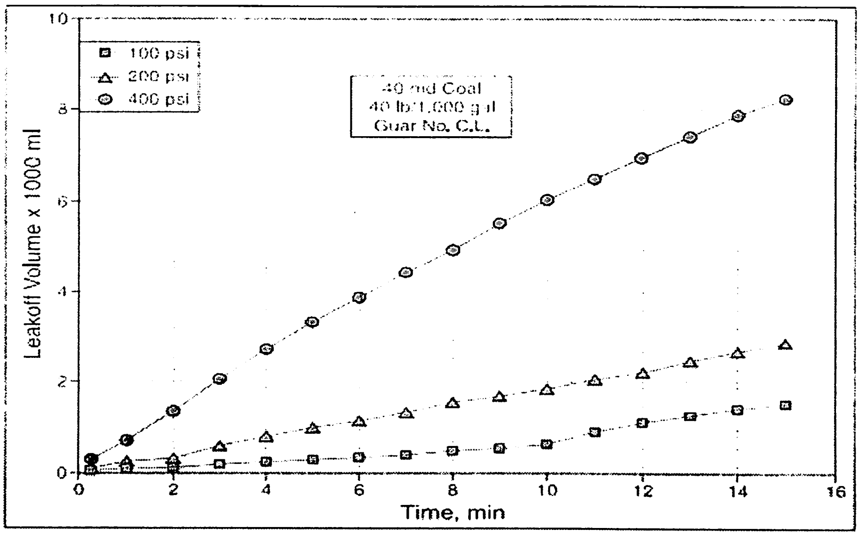


Fig. Leakoff in Fruitland cores

Although the polymers do not bridge the cleat openings to initiate a filter cake, it is possible to do so with the correct proppant size. The proppant may bridge the gap and polymer build upon it to prevent leakoff. The bulk of the fracturing fluid and larger size proppant is then diverted to a primary induced fracture. It is intimated that multiple fractures might be reduced to a single dominant fracture and tortuosity of the single fracture reduced by use of proppant slugs. Slugs of 100-mesh or 40/70-mesh sand early in the pad could direct the fluid and proppant to a single fracture.

Sand of 100-mesh in concentrations as low as 2 lb/gal proved effective in reducing leakoff to an insignificant level by facilitating the formation of a filter cake.

leakoff progressed unabated until the 100-mesh sand was added. Immediately, a filter cake formed to eliminate the loss of fluid at the higher 400-psi test condition. The results have implications for reducing fluid damage to the coals and for creating a single dominant hydraulic fracture. A leakoff coefficient, Cw, may be calculated using Eq. below to provide an approximation of how much fluid will leak into the formation, affecting height and penetration of the fracture.

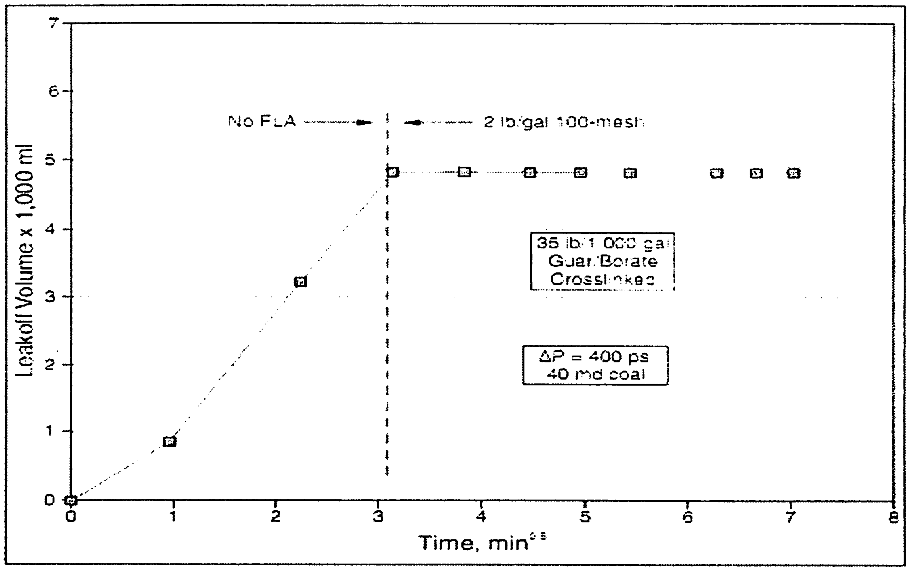


Fig. Leakoff prevention in Fruitland core

$$C_w = 0.0328 \frac{m}{2A}$$

where

Cw = leakoff coefficient, ft/min $^{1/2}$

m = slope of fluid-loss curve (filtrate volume/ (flow time)$^{1/2}$, ml/min $^{0.5}$

A = cross-sectional area of sample, cm^2

For the case of the 40-md Fruitland samples of Fig, Cw is determined to be 0.001 ft/min$^{0.5}$ with the 100-mesh sand in the fluid. The fine-mesh sand should be scheduled so that it is present as the cleats and fissures initially spread apart. Injecting the fine mesh later after the apertures are dilated may compound the problem. Cramer reports the effective use in the field of 40/70-mesh sand in the San Juan basin to seal cleats and to prevent leakoff. Palmer and Kutas also relate an effective use of 40/70-mesh sand preceding a coarser 12/20-mesh sand to seal the cleats and secondary pathways that open when fracturing San Juan coals. The mechanism was verified when radioactive tracers in the two sands indicated a segregation of the two sand sizes in the coal and placement of the two sizes in different fractures. The fine sand went to close secondary and tertiary fissures; the coarser sand propped the main fracture. A 100-mesh sand was used to control leakoff in the U.S. Department of Energy's multiwell experiment, resulting in completing the fracturing as designed. Since fluids may enter the cleats and secondary fissures when they are dilated from treating pressures, later cleanup at reduced pressures may leave gel trapped to reduce permeability. It becomes important, therefore, to restrict as much as possible the growth of complex fractures and fluid loss to them by properly selecting proppant size and schedule. Partly because of better control of leakoff, nitrogen foams are increasingly used in fracturing coals.

Chapter 7

Optimization of Hydraulic Fracturing

7. 1 Treatment optimization design procedure

Optimization procedures require methods to determine fracture geometry and production from the propped fracture. They may be in the form of a nomograph, analytical solutions, two- or three-dimensional (2D or 3D) models for geometry and productivity index (PI) calculations, type curves, or analytical or numerical reservoir models for production simulation. The accuracy of the optimization should increase with increasing sophistication of the models and the accuracy of the input parameters. Sensitivity studies of input parameters with uncertain values are warranted.

A basic procedure for economic optimization is as follows:

1. Select the fluid systems applicable to the formation to be fractured.

2. Select the proppant on the basis of stress and conductivity requirements.

3. Finding the maximum allowable pump rate on the basis of the pressure limitations of the wellhead and tubulars. The optimum injection rate is a balance of decreased fluid loss and increased horsepower as the rate is increased. Shear degradation, for some fracturing fluid systems, should also be considered.

4. Select an appropriate fracture propagation model (e.g., pseudo-3D, or P3D) for the formation characteristics and pressure behavior on the basis of in-situ stress and laboratory tests, calibration treatments and log analysis (e.g., stress profile, gamma ray)

5.Develop the input data required for the selected geometry model(s).

6.Determine fracture penetration and fracture conductivity for a selected treatment size and proppant concentration by forward simulation or determine fluid and proppant volumes required and fracture conductivity obtained for a selected penetration using inverse simulation. Determine the optimum pad fraction. I the model does not account for polymer conductivity damage, an estimated damaged conductivity should be used

7.Determine the production rate and cumulative recovery over a selected time period for a specific propped penetration and its corresponding conductivity.

8.Calculate the present value of the net revenue other production based on a discount rate (i.e., the sum of the present values for each year of the selected period).

9.Calculate the total treatment cost including the costs associated with fluids, proppants and hydraulic horsepower.

10.Calculate the NPV for the fracture by subtracting the treatment cost from the well's discounted new revenue (step 9 minus step 8).

11 .Repeat the preceding computational cycle for incremental increases in length until the NPV decreases or a maximum length is reached.

12.Construct curves showing the fracture NPV or other appropriate economic criteria versus fracture penetration. When the NPV starts to decline with increasing fracture lengths, the cumulative production for the specific lengths will still be increasing. The cycle can be repeated for other materials or conditions such as other fluids and additive concentrations, injection rates, proppant types and maximum proppant concentrations or even with other geometry models. The process can easily become consuming, and the number of iterations should be governed by the accuracy required as well as the accuracy of the input parameters. The cycles can be repeated for sensitivity to parameters to determine bounds. The most important input parameters and those with the greatest potential for error are formation permeability and fracture conductivity. Fortunately, a number of economic models combine geometry and reservoir models to allow making detailed studies in a reasonable amount of time. Economic optimization among different fracturing fluids such as oil-base, water-base and foam fluids is difficult. These fluids are usually chosen for compatibility with formation fluids or cleanup properties, and their economic benefit cannot be quantified unless features such as formation damage, polymer damage to proppant pack and cleanup time can be determined by the production models or included by some other means in the analysis. As an example, if it is known that a foam fracturing fluid will reduce the cleanup time, the cost of cleanup can be reduced for the foam fluid relative to that for a nonfoam fluid. Some risk factor and uncertainty can also be associated with various input parameters and behavioral assumptions.

7. 2 Fracture conductivity

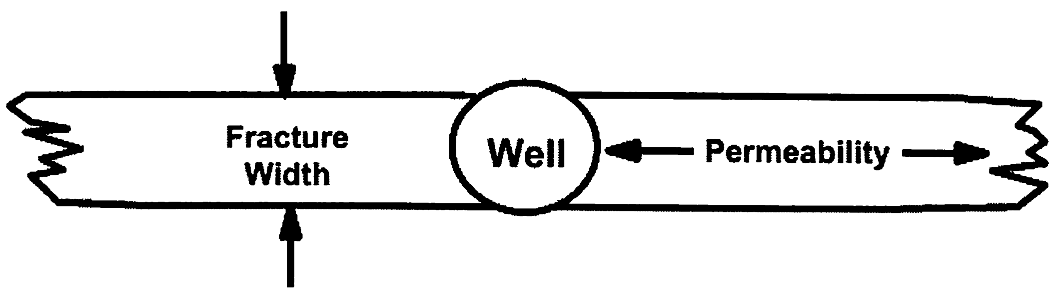
The fracture conductivity is the product of propped fracture width and the permeability of the propping agent, as shown in Fig.. The permeability of all the propping agents, sand, resin-coated sand, and the ceramic proppants, will be 200+ darcies when no stress has been applied to the propping agent. However, the conductivity of the fracture will be reduced during the life of the well because of increasing stress on the fracture, stress corrosion affecting the proppant strength, proppant crushing, proppant embedment into the formation, and damage due to gel residue or fluid loss additives.

1) Fracture Conductivity, wkf

wkf = fracture width x fracture permeability

2) Propped fracture width is primarily a function o

proppant concentration



The effective stress on the propping agent is the difference between the in-situ stress and the flowing pressure in the fracture, as shown in Fig. As the well is produced, the effective stress on the propping agent will normally increase because the value of the flowing bottom hole pressure will be decreasing. However, as can be seen by examining Eq , the in-situ stress will decrease with time as the reservoir pressure declines. This phenomenon of decreasing in-situ stress as the reservoir pressure declines was proven conclusively by Salz.In shallow coal seam reservoirs, the effective stress on the propping agent is always low and does not normally affect the fracture conductivity.

- **The stress on proppant (P_{eff}) increases as the flowing bottomhole pressure decreases**

$$\Delta P_{eff} = \sigma_{insitu} - P_{wf}$$

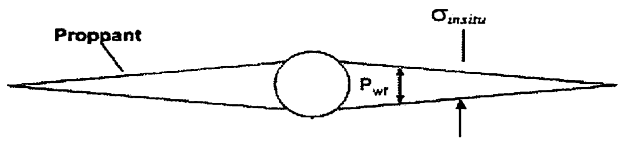


Fig. Differences is fracture

conductivity vs. increasing effective stress on the propping agent for a variety of commonly used propping agents. The data in Fig. clearly showthat for shallow wells, where the effective stress is less than 4000 psi, sand can be used to create high conductivity fractures. As the effective stress increases to larger and larger values, then the higher strength, more expensive propping agents must be used to create a high conductivity fracture.

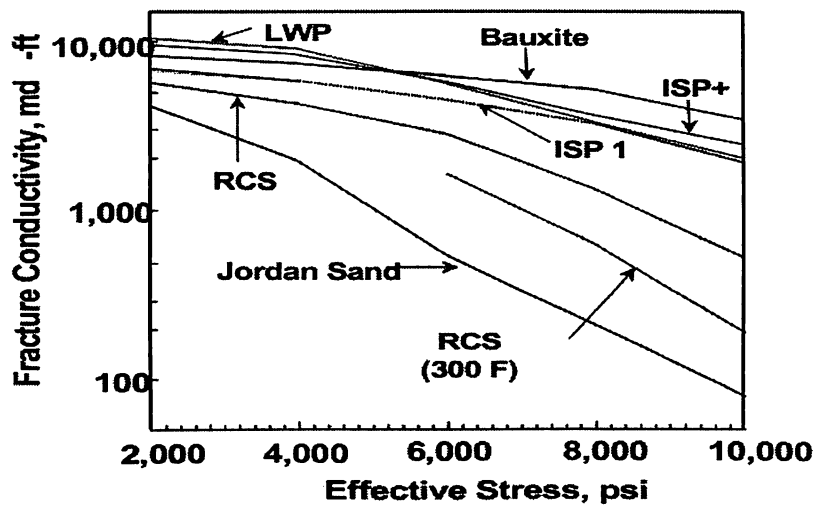


Fig. effect of stress

7.3 Non-Darcy Effects

The previous discussion of conductivity is based on Darcy's law, for which the pressure drop for fluid flow is directly proportional to velocity. Cooke and Holditch and Morse demonstrated the role of conductivity with a non-Darcy flow effect that adds an additional pressure drop that is proportional to the product of a turbulence factor and the velocity squared.

They showed that the pressure drop for this component can exceed that of Darcy flow with high-velocity production. Problems in design optimization of proppant conductivity are that the velocity varies down the fracture and the turbulence factors vary with the proppant type as well as the proppant's change in permeability during crushing and with fluid residue .

The effects of saturation and multiphase flow can increase the non-Darcy effects. Methods to correct the dimensionless conductivity term used in fracture design and well test analysis have been developed by Holditch and Morse, Guppy and Gidley .However, numerical simulation is usually required for accurate prediction and evaluation.

Concern for possible non-Darcy effects is another reason for the overdesign of conductivity. Because the velocity is affected by the width, doubling the propped width reduces the non-Darcy effects by a factor of 4, which may be more economical than using a higher priced proppant that has higher permeability and requires less width. This depends on the portion of the total pressure that results from the non-Darcy effects. However, it may not be good practice to use a lower permeability proppant at higher concentrations to achieve more width to try to overcome non-Darcy effects. The production velocity for fractures in low- permeability formations is usually low enough to not have significant non-Darcy effects. Again, numerical simulation is generally required to assess non-Darcy effects and achieve an optimum design.

7.5 Proppant Selection

A major consideration in proppant selection is optimizing permeability or conductivity versus the associated cost and benefit. The permeability of various proppants versus stress is shown in Fig. The proppant with the highest permeability is not always the optimum choice. The volume and cost required to obtain an optimum or desired conductivity should be considered. plot of relative proppant volume versus closure stress for different proppant types (Elbel and Sookprasong, 1987).

The relative proppant volume Vrp in lbm/md-ft^3 reflects the amount of proppant required to achieve a specific conductivity:

$$V_{rp} = \rho_p (1 - \varphi_p) / k_f ,$$

where ρp is the proppant density in lbm/ft3, φp is theporosity of the propped fracture, and kf is the fracture permeability (i.e., the permeability of the proppant in the fracture).

As stress increases, the relative proppant volume (RPV) increases but more significantly for low-strength proppants because of their loss of both permeability and porosity.

7.6 Treatment size

If it is assumed that the fracturing fluid and injection rate were selected by considering proppant transport,fluid loss, and horsepower and pressure limits, the other major design considerations are treatment size, type of proppant and proppant scheduling. A general statement can be made that the greater the propped fracture length and the greater the proppant volume, the greater the production. Limiting effects are imposed by factors such as the size of the production string, limit of achievable fracture conductivity and fracture height growth, in addition to well spacing. Within these constraints the size of the treatment should ideally be based on the optimum fracture penetration determined by the economic considerations discussed earlier. A plot of NPV versus propped penetration gives for a premium ISP and sand at concentrations of 10, 14 and 16 ppg. The NPV is less for sand at 10 ppg and the 1-year optimum is achieved at 500- to 600-ft penetration. The more permeable premium proppant at 16 ppg with a penetration of 900 ft increases the NPV by 35%. Although the maximum NPV is achieved for a specific penetration, additional penetration results in more production—but at a higher cost.

The role of fracturing fluid viscosity and leakoff characteristics is generally well known for fracture propagation and the placement of the propping agents; however, other properties must also be considered. The selected fracturing fluid should correctly balance the following, usually conflicting, properties and features:

• adequate fluid-loss control

• viscosity stability during placement for adequate proppant transport

• compatibility with the formation rock and reservoir fluids

• low friction loss in the pipe

• minimal damaging effects on proppant permeability

• controlled breaking and cleanup properties

• ease in mixing

• minimum disposal problems

• operational safety

• environmental safety

• economical price.

The last three considerations may eliminate systems that may otherwise be applicable. The first seven con-siderations are controlled to various degrees by additives. Experience in an area also influences the selection of a fluid. Experience can be either positive from "fluid proof testing" or negative, impeding the consideration of potentially more effective fluid systems. Figure 10-8 provides a general guideline for fluid selection with a distinction between oil and gas wells. Experience has shown that both water- and oil-base fluids have been used successfully in oil and gas wells. The greatest concern is the use of oil-base fluids in dry gas wells; however, they have been used in gas condensate wells.

After the fluid considerations have been balanced for the important properties of fluid loss and viscosity, the related additive concentrations remain for consideration.

7.7 Viscosity effects

The ability of fracturing fluids to transport proppants over long distances can be the limiting factor in fracture length optimization. Because of the problem of viscosity degradation with time and temperature, treatments usually start with a higher viscosity than that required in the later stages. This has resulted in the development of highly viscous, crosslinked fracturing fluids. Technology in fracture fluid chemistry continues to evolve to minimize the role of temperature on viscosity degradation.

Proppant transport concerns typically result in designing the treatment with a fluid viscosity higher than necessary. Nolte showed that without complete consideration of the effects of the fluid's behavior on the proppant settling rate, the design viscosity may be up to 50 times greater than required. The polymer concentration in water-base fracturing fluids should be minimized because of the adverse effects of residues on proppant conductivity and higher pressures on fracture geometry. Schlottman, White and Daniels and Nolte showed the benefits of tapered polymer loading during a treatment. The polymer concentration is based on maximum exposure to time and temperature for different segments of the fracturing fluid during injection. Not only is there a savings in polymer cost, but there is also less potential polymer damage to the proppant pack permeability and less potential of exceeding a critical net pressure for efficient fracture extension. Experience indicates that a viscosity as low as 50 cp at 170 s^{-1} is sufficient for proppant transport in a crosslinked fluid.

Concerns about polymer damage to the proppant pack and improvements in fluid systems and mixing have resulted in treatments using low-guar fluids and polymer-free, water-base fluids. Higher polymer concentrations can result in higher fluid efficiency because of the effect of the lower fluid-loss rate through the wall filter cake Cw and the viscosity control leakoff effect Cv, greater fracture width from the higher net pressure or both cases.

7. 8 Economic optimization

Economic optimization of hydraulic fracture treatments allows the production engineer to design a fracture treatment that optimizes the production rate and reserve recovery from a well to maximize well profitability. In addition, a good understanding of the key parameters for the fracture treatment can be developed from the optimization study. For example, Fig. 10-1 is a plot of 1-year NPV versus the productive fracture half-length xf in a 0.01-md formation. This figure shows the relationship among length, conductivity and portability. For penetrations from 200 to 600 ft, about the same NPV is produced by proppant concentrations of 6 to 14 ppg. However, the net production and therefore cash flow—will be higher with the higher concentrations. At 1000-ft penetration, concentrations from 10 to 14 ppg yield about the same NPV and are significantly greater than when using 6 ppg. Increasing the fracture length improves the profitability of a well in this reservoir but also requires increasing fracture conductivity for most penetrations.

To estimate the cost of a fracturing treatment, the variable costs can be added to some fixed cost not directly associated with treatment size:

• variable fluid cost = \$/unit × units of fluid The unit cost includes

– fracturing fluid plus additives

– mixing and blending charges

– transportation, storage and disposal charges (commonly included in other fixed costs).

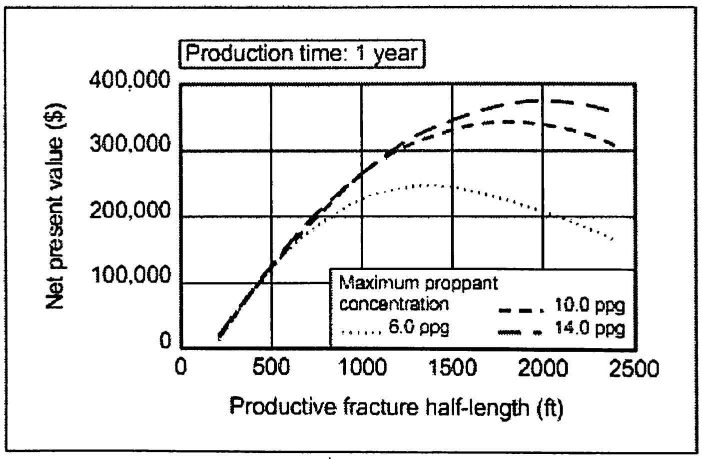


Figure. Net present value versus productive fracture half-length for a 0.01-md formation.

• Variable proppant cost = \$/unit × units of proppant

The unit cost includes

– Proppant

– Proppant transportation to location and storage

– Proppant pumping charges.

• Variable hydraulic horsepower (hhp) cost

= \$/hhp × Injection rate × surface treating pressure/40.8 × Standby hhp factor

• Other fixed costs

– Mobilization

– Personnel

– Well preparation (work over rig, etc.)

– Cleanup costs (coiled tubing, disposal if not included as a fluid unit cost, etc.).

Chapter 8

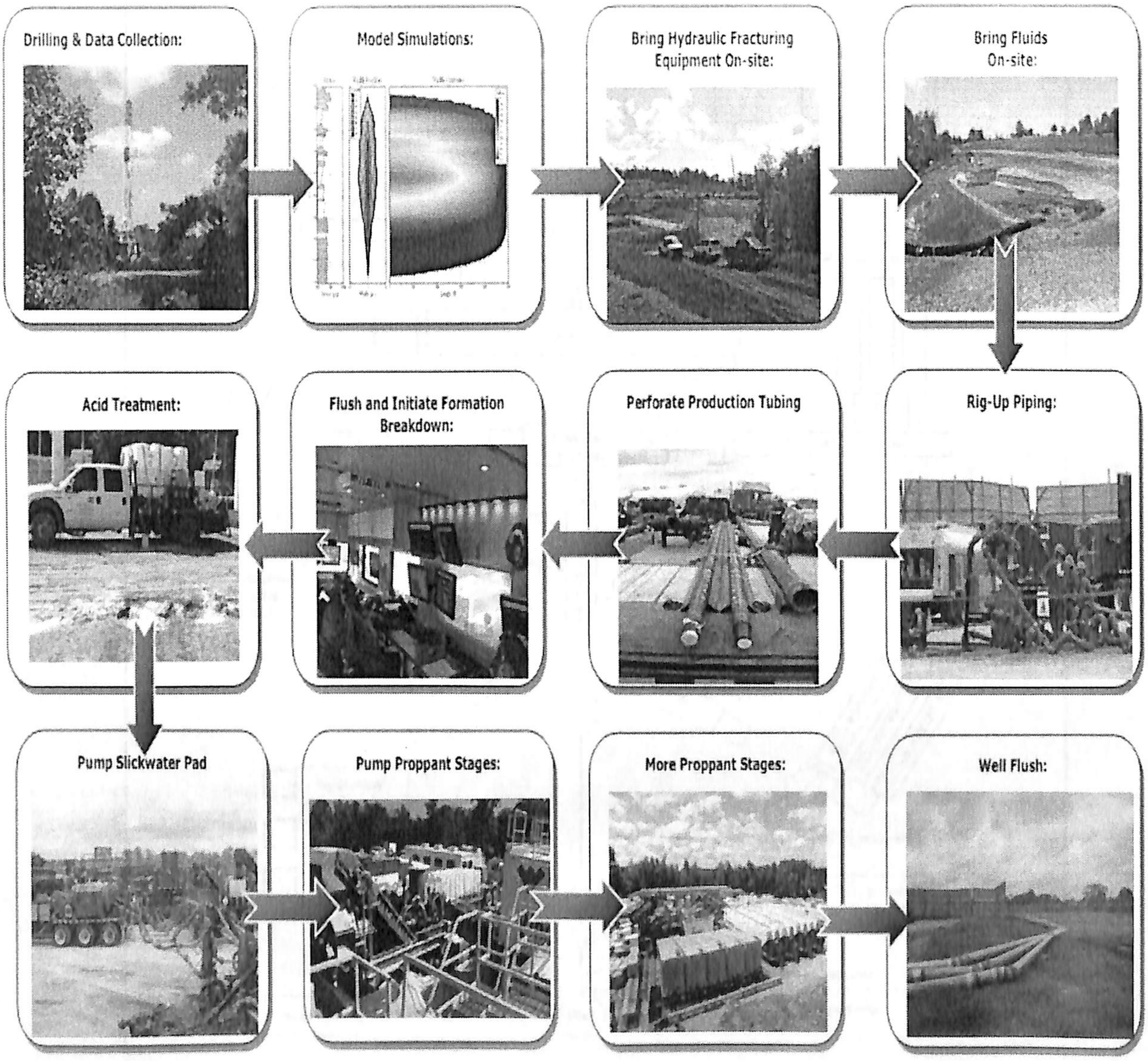
Hydraulic Fracturing Process and Equipment Used

Hydraulic fracturing of the horizontal shale gas wells is performed in stages. Lateral lengths in typical CBM development wells are from 1,000 feet to more than 5,000 feet in length. Because of the length of exposed wellbore, it is usually not possible to maintain a downhole pressure sufficient to stimulate the entire length of a lateral in a single stimulation event. As such, hydraulic fracture treatments of shale gas wells are performed by isolating portions of the lateral and performing multiple treatments to stimulate the entire length of the lateral portion of the well.

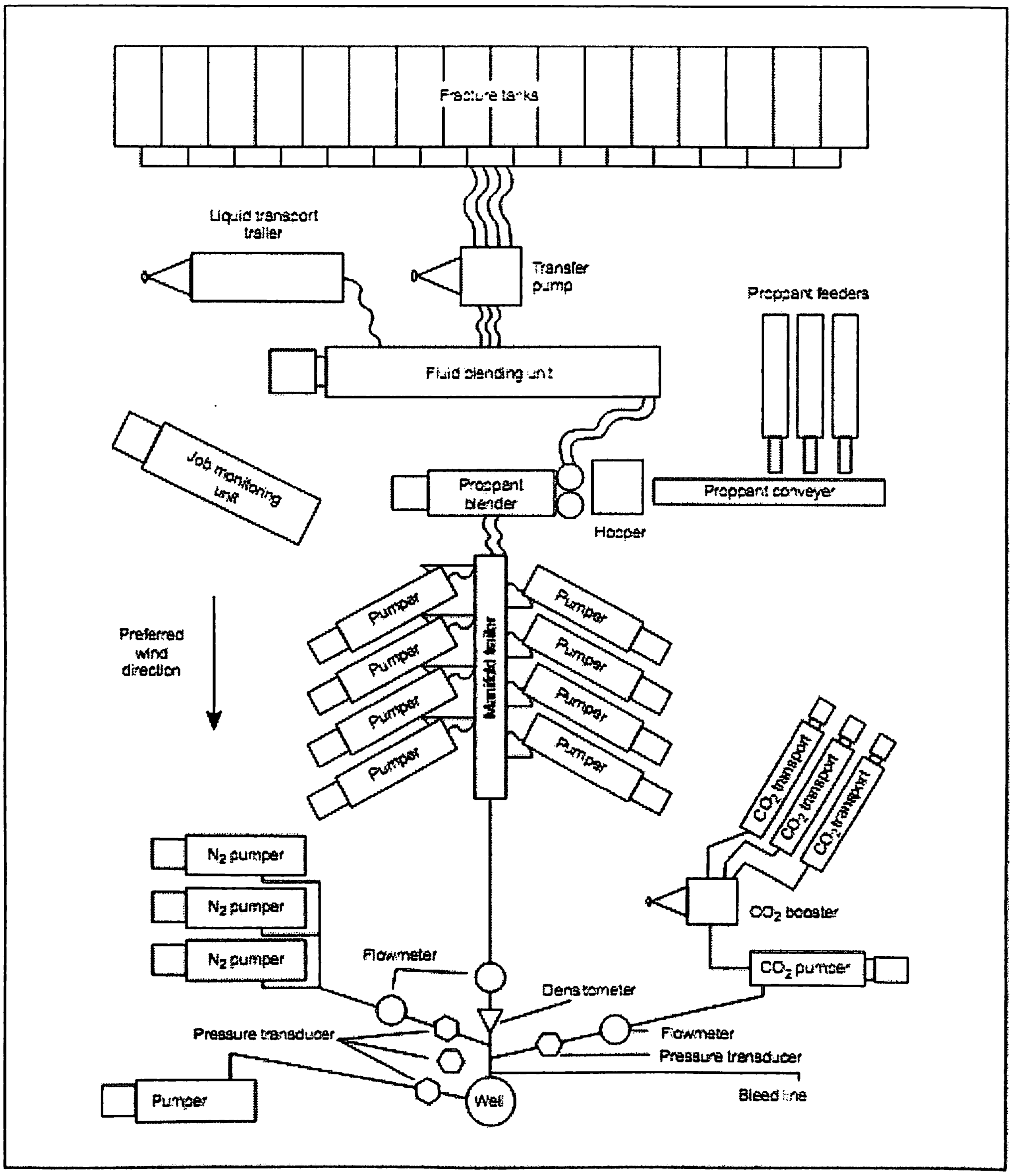
Fig presents a process flow diagram showing the order of events that occur for one stage of a hydraulic fracture treatment. A hydraulic fracture treatment starts with bringing equipment onsite. Once onsite, the equipment is "rigged up". Rig-up involves making all of the iron connections necessary between the frac head on the well, frac pumps, manifold trailers, and additive equipment which feed fluids and additives into the frac pumps. Iron connections are typically secured with restraints to ensure safety in case of iron failure. Each fracture stage is performed within an isolated interval within which a cluster of perforations is created using a perforating tool. Perforations allow fluids to flow through the casing to the formation during the fracture treatment and also allow gas to flow into the wellbore during the production phase of operations. In order to isolate each fracture stage of a fracture treatment, a packer is used to isolate each fracturing interval. One type of packer used for creating zonal isolation is a ball packer which works by having a steel ball pumped into a seat point typically located where the last fracture stage was completed. The ball acts as a sealing agent to the previously treated zone isolating the next treatment interval.

individual fracture treatment stages typically include multiple sub-stages, during which different fluids and concentrations of proppants are pumped into the well. Initial sub-stages are typically performed as a flush and often may simply include pumping fresh water into the wellbore. Following the fresh water flush is an acid flush to clean cement from the perforations and near the wellbore area to facilitate the flow of fluids during the fracturing process.

Following the acid flush is typically a spacer which pushes the acid into the formation and begins t he propagation of fracturing. After the spacer is pumped, the next sub-stage is typically a well shut -in during which the fracture gradient for the formation is calculated. When the well is opened aga in, a clean fracture fluid pad is injected to lubricate well tubing and formation fractures aiding in th e delivery of the proppant sub-stages. The next sub-stages are a series in which proppant is used to create and maintain fractures.



The number of sub-stages is determined by volumes of proppant and fracture fluid that are designe d for the fracture treatment. For a multiple proppant treatment schedule, proppant concentration is typically maintained when a transition from one proppant to another occurs such that the final slurr y density would be the same as the initial slurry density of the next stage. Once the prescribed vol ume of fluids and proppant has been pumped, a final flush is performed to clean the wellbore and t ubing of proppant.



For a hydraulic fracturing treatment, specialized equipment is necessary toperform the steps requir ed to stimulate the formation.This equipment includes storage tanks, pumps, chemical trucks and a variety of pipes and fittings to connect everything together. The following is a brief description of some items that are typically utilized during a horizontal shale gas well fracture treatment. Fractur e or "frac" tanks are large trailer tanks which are designed to hold several hundred barrels of fresh water which is used as the base fluid for slickwater fracture treatments. Chemical trucks are flat be d trucks used to transport chemicals from site to site. Chemical additive trucks may also be used to transport some of the additives to the site, but these trucks also contain pumps which are used to p ump additives to the blenders.

Acid is typically transported to the job site by an acid transport truck, which can hold up to 5,000 g allons of acid. Acid transport trucks may have multiple compartments to allow transport of several different acids or additives. Acid can also be transported with an acid fracturing or backside pum p, which is a unit that pumps and holds pressure on the casing or to pump acid jobs. Sand storage units are large tanks which are used to hold the proppant (typically sand), these units feed sand to t he blender via a large conveyer belt. A sand storage unit may contain as much as 350, 000 to 450, 000 pounds of proppant.

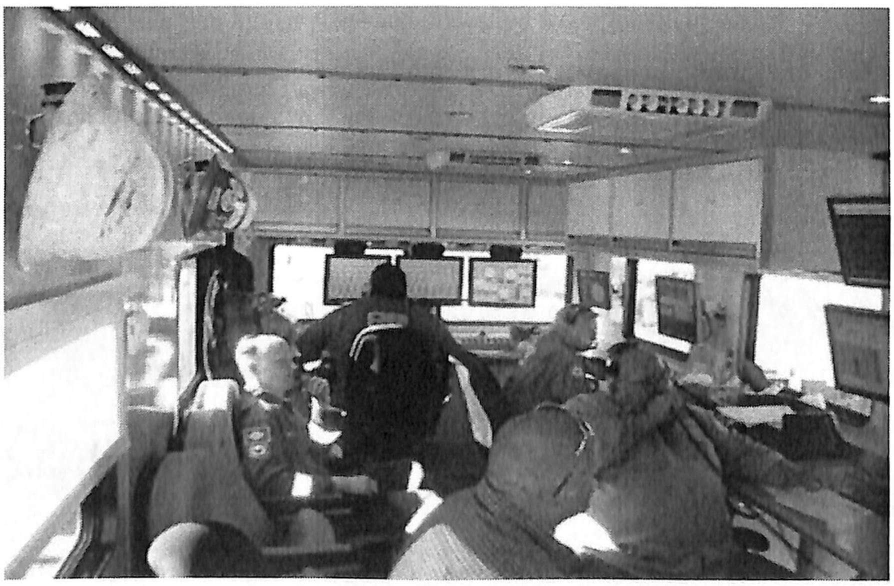
A blender takes fresh fluids from the frac tanks using suction pumps and combines the water with t he proppant in a hopper. Fluids and proppant are blended with other additives at the programmed concentrations; the slurry is then pressurized and transferred to frac pumps.

Frac pumps are high pressure pumps that pull fracturing fluids from a blender and pressurize the fl uid via a positive displacement pump prior to discharging the fluid into the manifold trailer

. The manifold trailer is a large manifold system which acts as a transfer station for all fluids, mixe d fluids from the blender pumps move through the manifold on the way to the pump trucks. Simila rly, pressurized fluids from the frac pumps are pumped through the manifold into the ground lines ac head. which transfer the fluids to the fracture head.

A technical moni toring vehicle (T MV) data van is t he work area for t he fracturing serv ice supervisor, en gineers, pump op erators and comp any representativ e. This van is wh ere activities asso ciated with the fr acture treatment are monitored an

d coordinated this includes monitoring all treatment pressures, chemicals, proppant density, fluid v elocity, pressures, and where all data is recorded and reviewed. Within the TMV the entire fractur e stimulation is tracked for each stage that is preformed.

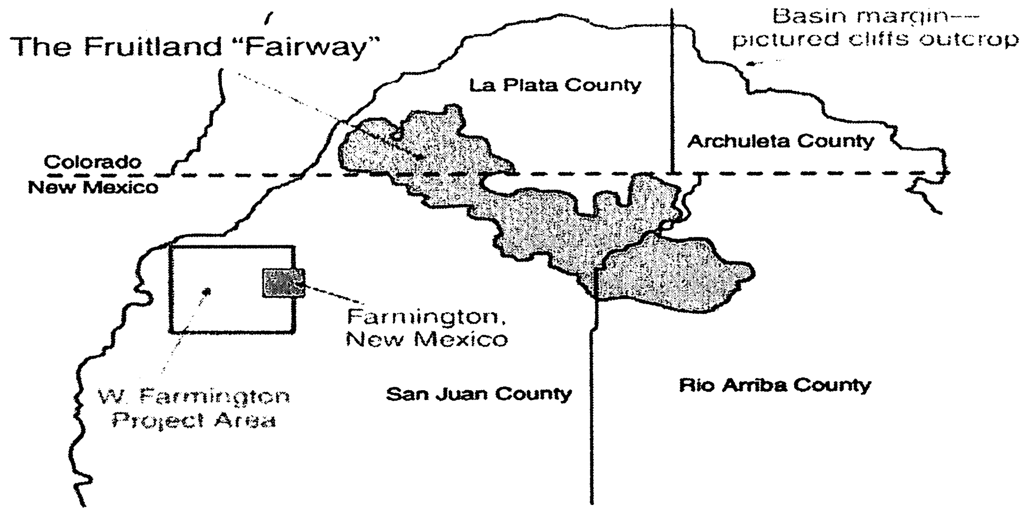


Hydraulic fracturing stimulations are monitored continuously by operators and service companies t o evaluate and document the events of the hydraulic fracturing treatments. Monitoring of fracture t reatments includes tracking the process with wellhead and downhole pressures, pumping rates, frac turing fluid slurry density measurements, tracking volumes for additives, tracking volumes of wate r, and ensuring that equipment is functioning properly. During a typical hydraulic fracturing event for a horizontal well, there may be more than 30 service company representatives on site performi ng and monitoring the stimulation as well as additional staff from the operator and perhaps the stat e oil & gas agency. This level of manpower also serves as an emergency response team should an unforeseen incident occur.

Refinement of the hydraulic fracturing process occurs as operators collect more resource specific d ata. This process generally helps to create a more optimized fracture patterns within the target for mation for purposes of increasing gas production as well as further ensuring that fractures do not g row out of the target formation. The refinement of the hydraulic fracturing process was a necessar y step in the success of the Barnett Shale as development moved away from the core area of the Ba rnett50. Hydraulic fracturing in some areas of the Barnett resulted in fractures extending into the u nderlying Ellenberger Formation. Wells in which fractures extended into the Ellenberger Formatio n had increased water production as water from the more water laden Ellenberger flowed into these wellbores50. This resulted in higher costs and undesired water handling issues. As a result, fractu ring processes have been refined and unintentional fracturing of adjacent zones has become a lesse r issues as the technology has evolved.

CASE STUDY: Hydraulic-Fracture Treatments in San Juan Coals Basin

Objectives: The two main objectives for a hydraulic fracture model in coals are optimization of job design and placement, and post treatment diagnostics. Fully functional 3D models can be used to obtain good estimates of the fracture dimensions. A grid-oriented fully functional 3D fracture simulator with shear decoupling can be especially useful in coals for post-treatment diagnostics if sufficient input data can be fixed from logs and diagnostic fracture-injection tests (DFITs).



In this case hydraulic fracturing and modeling in coal. Successful placement of hydraulic-fracture treatments was an issue in the upper Fruitland coals of this project area. The Fruitland coals in this area were divided into basal (S8 coal) and upper (S9 coal) units. Typically, S8-coal fracture treatments were relatively easy to place while the S9 coals were more difficult to treat across the region, resulting in occasional near-wellbore screen outs. West of Farmington, almost all S9-coal units were more difficult to treat, resulting in screen outs. The completion program in this project area was suspended to investigate, analyze, and address the problem accordingly.

Four problem-well stimulations across the project area were history matched with a grid-oriented fully functional 3D planar-fracture simulator. The analysis revealed that most perforations were not open before the treatment (causing excessive perforation friction) and that there was severe pressure-dependent leakoff (PDL) with an estimated PDL coefficient as high as 0.011 psi−1 in the S9 coals. Significant job-design changes needed to address these issues. The full length paper details lessons learned by use of this fracture model in understanding and then solving the problems faced during stimulation in this project area.

Reservoir Information and Geology

The West Farmington project, shown in Fig., is in the northwest part of the San Juan basin, spread across six townships. The coal rank in this area ranges between high-volatile-C and high-volatile-B bituminous coals, and all are slightly under saturated. The target coal seams are the lower Fruitland (S8) and upper Fruitland (S9) coals. The target seams increase in depth from west to east in the project area. The S8 coals are continuous in nature and vary from one to two seams, while the S9 coals are very discontinuous and vary from one to three seams. The average net thickness of the S8 coals is approximately 15 ft, while the combined average of all the S9 coal seams is 16 ft.

These coals have an ash content of 25 to 35% and a moisture content of approximately 6 to 9%. In the two samples tested, the in-situ gas content varied between 70 scf/ton for the S9 coals and 105 scf/ton for the S8 coals. DFITs from representative wells (Wells 1 and 2) revealed that the target coals were under pressured in this area. On the basis of available fracture-, closure-, and pore pressure gradients for both S8 and S9 coal seams, it was clear that a single stage high-rate fracturing treatment with limited entry would not treat both coal seams effectively.

Well A: S8 Coals. The S8 coals were perforated from 1,002 to 1,008 ft and from 1,023 to 1,025 ft with 3 shots/ft at 120° phasing and 0.42-in. estimated hole diameter. The design called for a low-gel-loading crosslinked-fluid system with 56,000 lbm of 16/30-mesh proppant pumped at 35 bbl/min. This fluid system exhibits the same viscosity as a conventional borate-crosslinked-fluid system but reduces gel loading by up to 33%. The reduced polymer loading, which causes less formation damage, is ideal for coals. The minimum and maximum sand concentrations in this design were 0.5 and 6 lbm/gal, respectively.

During the pumping of the 2-lbm/gals and stage, pressure started rising rapidly and a decision was made onsite to shut off the sand. Immediately, the pressure began dropping rapidly and the sand was restarted. The pressure continued declining throughout the remainder of the job until flush. Even though the entire job was placed without further problems, a timely intervention to cut the sand during the 2-lbm/gal sand stage prevented a screenout. Subsequently, this job was analyzed with the fully functional 3D fracture model. All the reservoir information used in the model was obtained from well logs and from the representative-well DFIT (Well 2). The history-match analysis revealed that only 49% of the holes were open initially, with a discharge coefficient of 0.45, and only approximately 27% of the holes were open when the near screenout occurred. The near-screenout and corresponding decrease in number of open perforations could be attributed to perforation plugging caused by sand settling. Field personnel later attributed it to poor fluid quality at that point. Once the fluid had sufficient viscosity to carry the proppant, the remainder of the job was placed without issue. However, the number of holes open at the start of the job remained a concern. The history match analysis did not reveal any PDL effects or near-wellbore damage issues.

Well A: S9 Coals. The S9 coals in this well were perforated from 904 to 908 ft, 960 to 962 ft, and 969 to 970 ft at 3 shots/ft with 120° phasing and 0.42-in.-diameter holes. The stimulation treatment was designed to pump 54,000 lbm of 16/30-mesh proppant with the low gel-loading-fluid system at a rate of 35 bbl/min. However, the job screened out when the 2-lbm/gal sand stage reached only 8,300 lbm of proppant placed. The job treated at a higher pressure from the beginning and resulted in a near-wellbore screenout. The history-match analysis revealed that only 28% of the holes were open at the start of the job, with a discharge coefficient of 0.80. The study also revealed that these S9 coals have very high PDL. A PDL value of 0.011 psi−1 was derived from the history match. A default value of 0.002 psi−1 usually is considered very high. The analysis also indicated a proppant-holdup factor of 6.0. This factor is a grid property used to account for the velocity of the proppant with respect to the fluid velocity. It is calculated internally in the model on the basis of fracture width, local shear rate, and local leakoff values. If this effect is important, then this factor can be used as a multiplier with a value less than 1, meaning that the proppant is moving faster than the fluid (laboratory situations); a value higher than 1 indicates that the proppant is being held up by interference with the fracture walls and is moving slower than the fluid. Values higher than 1 are common, especially when treating naturally fractured reservoirs such as coals. The effect of extremely high PDL and higher rates in conjunction with the smaller number of open perforations probably contributed to the screenout. The analysis did not reveal near-well-bore damage issues.

Well B: S9 Coals. In this well, the S8 coals were stimulated without issues. However, the S9-coal stimulation resulted in near-wellbore screenout when the 2.5-lbm/gal sand stage reached the perforations. After the S9-coal treatment screenout in Well A, the gel loading was increased in this well from 17 to 20 lbm/1,000 gal in an attempt to prevent screenout. However, the job screened out after 12,400 lbm of 16/30-mesh proppant was placed. The history-match analysis revealed that only 40% of the perforations were open at the start and that the S9 coal had very high PDL. The PDL value and proppant-holdup factor were very similar to the S9-coal analysis from Well A. Thus, it appeared that the S9 coals in this area have extremely high PDL that must be accounted for. Higher injection rates and increased gel loading did not appear to solve the problem.

Well C: S9 Coals. Problems occurred during the fracture treatment in this well; hence, it was analyzed with the grid-oriented, fully functional 3D planar-fracture model. The three S9 coals in this well were perforated. The design called for a low-gel-loading-fluid system with 70,000 lbm of 16/30-mesh proppant to be pumped at a design rate of 35 bbl/min. The treating pressure was so high initially that no proppant was pumped for a period. Three 0.5-lbm/gal sand-slug treatments were pumped. After the third slug treatment, the treating pressure dropped slightly.

The maximum injection rate obtained was between 18 and 19 bbl/min. Because the pressure dropped after the third slug treatment, the rate was slowly increased and the sand stages were started. However, the pressure started increasing toward the maximum pressure limit, and pumping of the sand was stopped. After the sand was turned off, the pressure started falling rapidly and attempts were made to restart the sand stages. However, because so much water had been pumped, there was no water available to place the remainder of the job. Therefore, the job was switched to flush after placing approximately 6,900 lbm of sand.

The history-match analysis revealed that only 10% of the perforations (4 out of 39) were open at the start of the job, with a discharge coefficient of 0.85. This limited number of holes contributed to the high treating pressures observed during the job. After the third lug attempt, an equivalent of approximately three additional holes were opened, leading to the pressure drop. The analysis also revealed a very high process-zone stress of approximately 2,500 psi near the middle and lower S9 coals, indicating possible near-wellbore damage. The history match indicated a PDL value equivalent to 0.0021 psi−1.

Well D: S8 and S9 Coals. This well was included in the study because of poor production. The S8- and S9-coal stimulation treatments were analyzed to determine whether the poor production could be attributed to ineffective stimulation. The S8-coal stimulation treatment was placed without problems. The history-match analysis revealed no PDL or near-wellbore damage issues. However, only 45% of the perforations were open at the start of the job, with a discharge coefficient of 0.60. It appears that if the S8 coals had been broken down before the fracture treatment, the jobs could have been placed without problems because there were no PDL or near-wellbore damage issues, such as those with the S9 coals. The S8 coal was stimulated effectively in this well. The three S9-coal seams in this well were perforated at 891 ft, 895 to 899 ft, and 952 to 953 ft at 3 shots/ft with 120° phasing and 0.42-in.-diameter holes. The fracture treatment was designed to place 74,000 lbm of 16/30-mesh proppant with a low-gel-loading hybrid-fluid system at a design rate of 30 bbl/min. The history-match analysis of the fracture treatment showed that the pressure started increasing when the 0.5-lbm/gal sand stage was started. The rate was increased on-the-fly from 30 to 35 bbl/min in an attempt to negate this pressure increase. After the 0.5-lbm/gal sand stage reached the perforations, the pressure started dropping rapidly and the job was placed without further problems. The history-match analysis revealed a PDL value of 0.002 psi−1,which is similar to the values observed with the S9 coals of Well C. The increase in rate did not affect the job significantly because of the lower PDL value. This well is closer to Well C in the West Farmington project area and thus has similar PDL values. The analysis also revealed a very high process-zone stress (3,000 psi) in the lower two S9-coal seams, indicating possible near-wellbore damage. In addition, only 55% of the perforations were open at the start of the job, with a discharge coefficient of 0.45. A comparison of the proppant distribution from the history match with the actual tracer log showed that the top S9-coal seam was effectively stimulated, but the lower two S9-coal seams were not stimulated effectively. Thus, it appears that, except for the lower S9-coal seams, all the coals were stimulated effectively in this well.

The well did start producing better after a few months. The initial poor production could be attributed to a combination of factors, including cleat damage during the drilling process, pumping issues, and part of the S9 coal not being stimulated. However, with time and with pumping issues addressed, production began to increase. The well is no longer considered a poor producer.

Conclusion

Formation breakdown before any fracture treatment, especially in a limited-entry treatment, is very important. It will resolve the issue of high treating pressures caused by fewer perforations being open. It is critical in high-permeability coals because if design rates are not obtained because of higher treating pressures, then the leakoff caused by high permeability cannot be matched, resulting in screenouts.

Therefore, it was agreed to break down all perforations before each fracture treatment. The S8-coal fracturing treatments should be relatively easy to place in this project area, provided that the perforations are broken down and there are no fluid issues. The S8 coals do not have high PDL. The S9 coals in this project area have extremely high PDL in the southern part and moderately high PDL in the north-central and northern parts. This variance was not observed from the representative well DFITs because the DFITs were pumped at a lower rate than the fracture treatments. High PDL is the main reason for the S9-coal screenouts. High PDL can be addressed by increasing the 0.5-lbm/gal sand stage to attempt bridging the multiple fractures and create one dominant fracture. It also can be addressed by use of 20/40-mesh sand rather than 16/30-mesh sand, to handle the fracture-width effects caused by high PDL. In cases of high PDL, it also must be possible to adjust rates as needed.

For the S-9 coal in Wells A and B, the overall leakoff coefficient at 200 psi above the fissure-opening pressure is nine times the original value, whereas the overall leakoff coefficient at 200 psi above the fissure-opening pressure is only 1.5 times the original value for the S9 coals of Wells C and D. Consequently, any increase in rate to overcome the effects of PDL will increase the leakoff exponentially.

When stimulation work was restarted in this project, all the recommendations from the study, except for the switch to 20/40-mesh sand, were implemented in the field successfully, and the screenout issues were resolved. Another important factor considered in the design optimization was the total net pressure developed during the job. To help prevent the gel from dehydrating and causing damage to the coals, a 1,000-psi limit was set.

Treatment design

Treatment design of Hydraulic fracturing job of a sample well is carried using a HF simulator "Fracpro" widely used

in industry for designing and optimization of HF jobs. The design inputs, selection of frac fluid and proppant,

treatment schedule and outcome of simulation is presented below:

Design inputs:

Well completion:

- Drilled hole : 4205 m
- 7" casing, p-110, 26ppf : 4205 m
- Tubing shoe : 3812 m
- Packer depth :3812 m
- Perforation, 4 spf : 4084 – 4096 m

Reservoir parameters:

- Reservoir type : Gas
- Porosity : 0.100
- Permeability : 5 mD
- Reservoir temp : 352 deg F
- Reservoir pressure:5837 psi

Lithology Parameters

Layer #	TVD (m)	Closure Stress Grad (psi/ft)	Lithology
1	0	0.800	User Spec 1
2	761.0	0.750	Sandstone
3	1420.0	0.680	Limestone
4	1495.0	0.750	Sandstone

Layer #	TVD (m)	Closure Stress Grad (psi/ft)	Lithology
5	2150.0	0.850	Shale
6	3975.0	0.750	Sandstone
7	4276.6	0.800	User Spec 1

- We have used different types of frac fluids for the experiment, but this fluid having high viscosity is the most well suited.
    - Name : **YF660HT W/10 LB/K J**
    - Manufacturer : Schlumberger
    - Viscosity : 283.01 cp
    - Conductivity : 0.0533 lbf*s^n/ft2
    - Proppant selection for our experiment was based on the closure stress. Due to the high closure stress in this field, we selected the proppant **Carbo-Lt2040.**

Treatment Schedule

Stage#	Elapsed Time (min:sec)	Fluid Type	Clean Volume (bbls)	Proppant Conc. (ppg)	Slurry Rate (bpm)	Proppant Type	Cumul Time (min:sec)
1	6:39	YF660HT W/10 LB/K J	100.0	0	15.00		6:39
2	10:08	YF660HT W/10 LB/K J	50.0	1.00	15.00	Carbo-Lt2040	10:08
3	13:46	YF660HT W/10 LB/K J	50.0	2.00	15.00	Carbo-Lt2040	13:46

Stage#	Elapsed Time (min:sec)	Fluid Type	Clean Volume (bbls)	Proppant Conc. (ppg)	Slurry Rate (bpm)	Proppant Type	Cumul Time (min:sec)
4	18:18	YF660HT W/10 LB/K J	60.0	3.00	15.00	Carbo-Lt2040	18:18
5	24:34	YF660HT W/10 LB/K J	80.0	4.00	15.00	Carbo-Lt2040	24:34
6	31:05	YF660HT W/10 LB/K J	80.0	5.00	15.00	Carbo-Lt2040	31:05
7	42:54	YF660HT W/10 LB/K J	140.0	6.00	15.00	Carbo-Lt2040	42:54
8	58:36	YF660HT W/10 LB/K J	180.0	7.00	15.00	Carbo-Lt2040	58:36
9	64:48	YF660HT W/10 LB/K J	93.0	0	15.00		64:48
10	69:48	SHUT-IN	0	0	0		69:48

The report generated using Fracpro software:

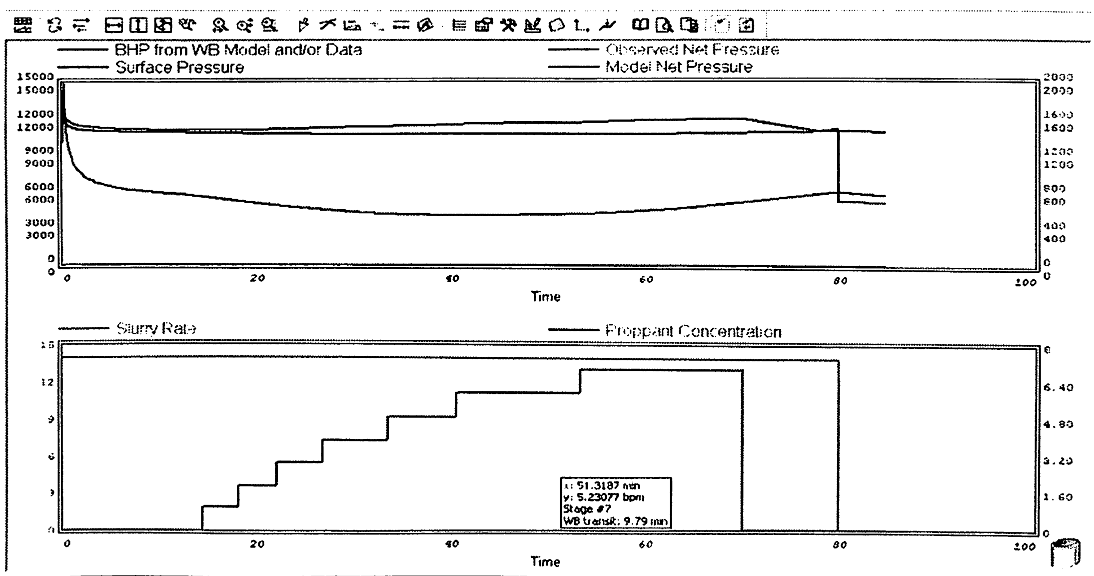
Total Summary

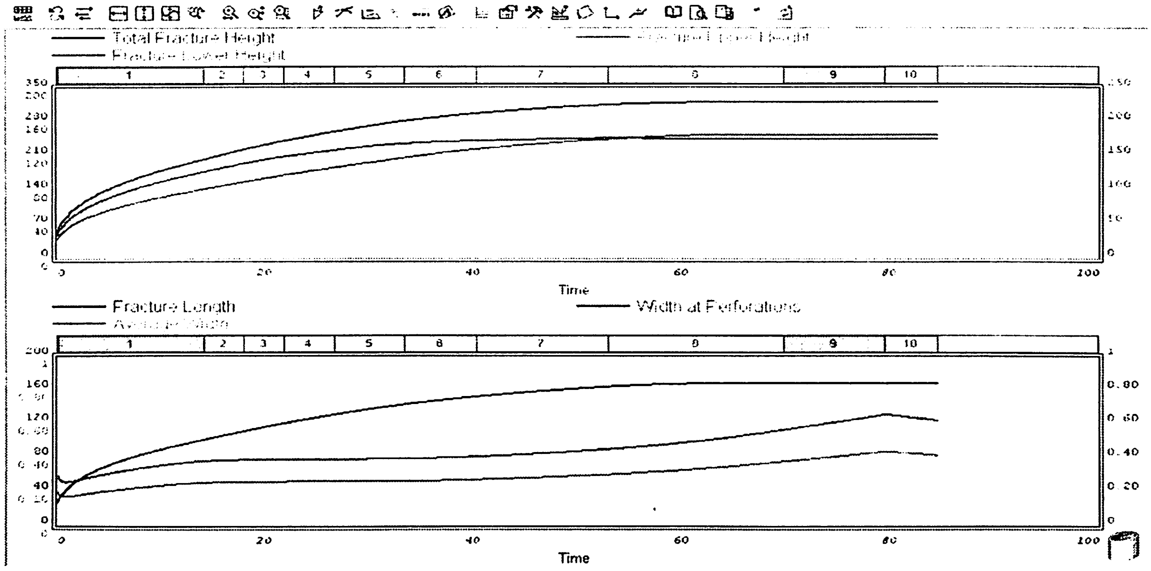
Model has run until (min)	69.90 min		
Min Surface Pressure (psi)	11133.84 psi	**Max Surface Pressure (psi)**	14908.23 psi
Max Hydraulic Power (hp)	5474.30 hp	**Average Hydraulic Power (hp)**	4573.23 hp
Total fluid (bbls)	834.15 bbls	**Total proppant (tonnes)**	60.08 tonnes

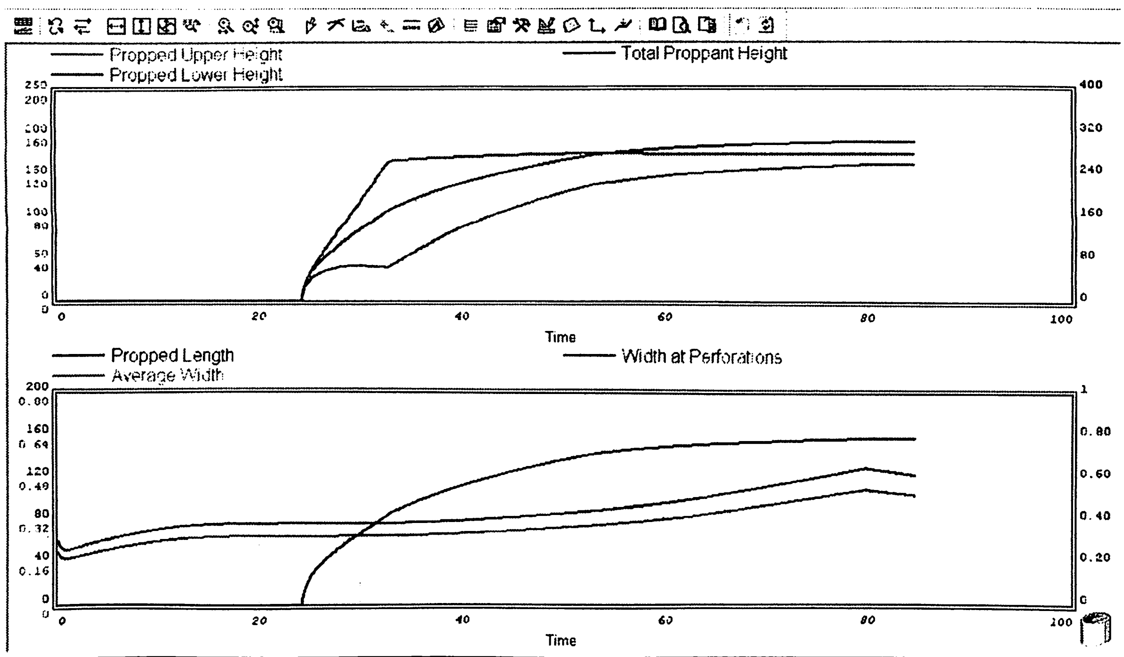
Summary for Fracture at 4084 (m)

Fracture length (ft)	159.82 ft	**Propped length (ft)**	152.35 ft
Fracture upper height (ft)	168.47 ft	**Propped upper height (ft)**	154.50 ft
Fracture lower height (ft)	132.11 ft	**Propped lower height (ft)**	132.02 ft
Max width at well (in)	0.64 in	**Average proppant concentration (lb/ft2)**	1.79 lb/ft2
Dimensionless Cond. Ratio	27.88	**Fracture efficiency**	0.42
Total fluid (bbls)	844.84 bbls	**Total proppant (tonnes)**	55.54 tonnes

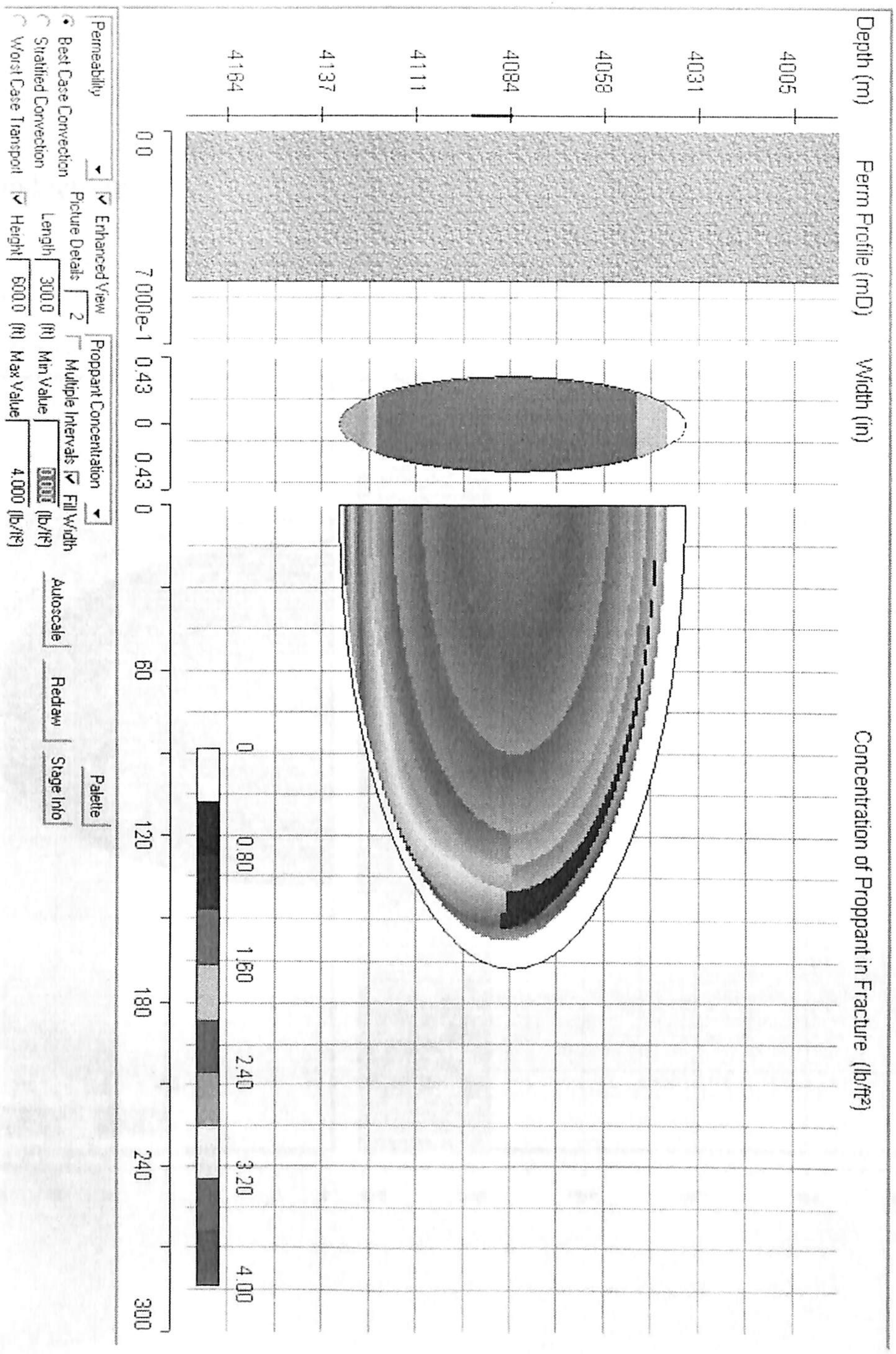
The pressure trend and dimentions are shown in the following graphs



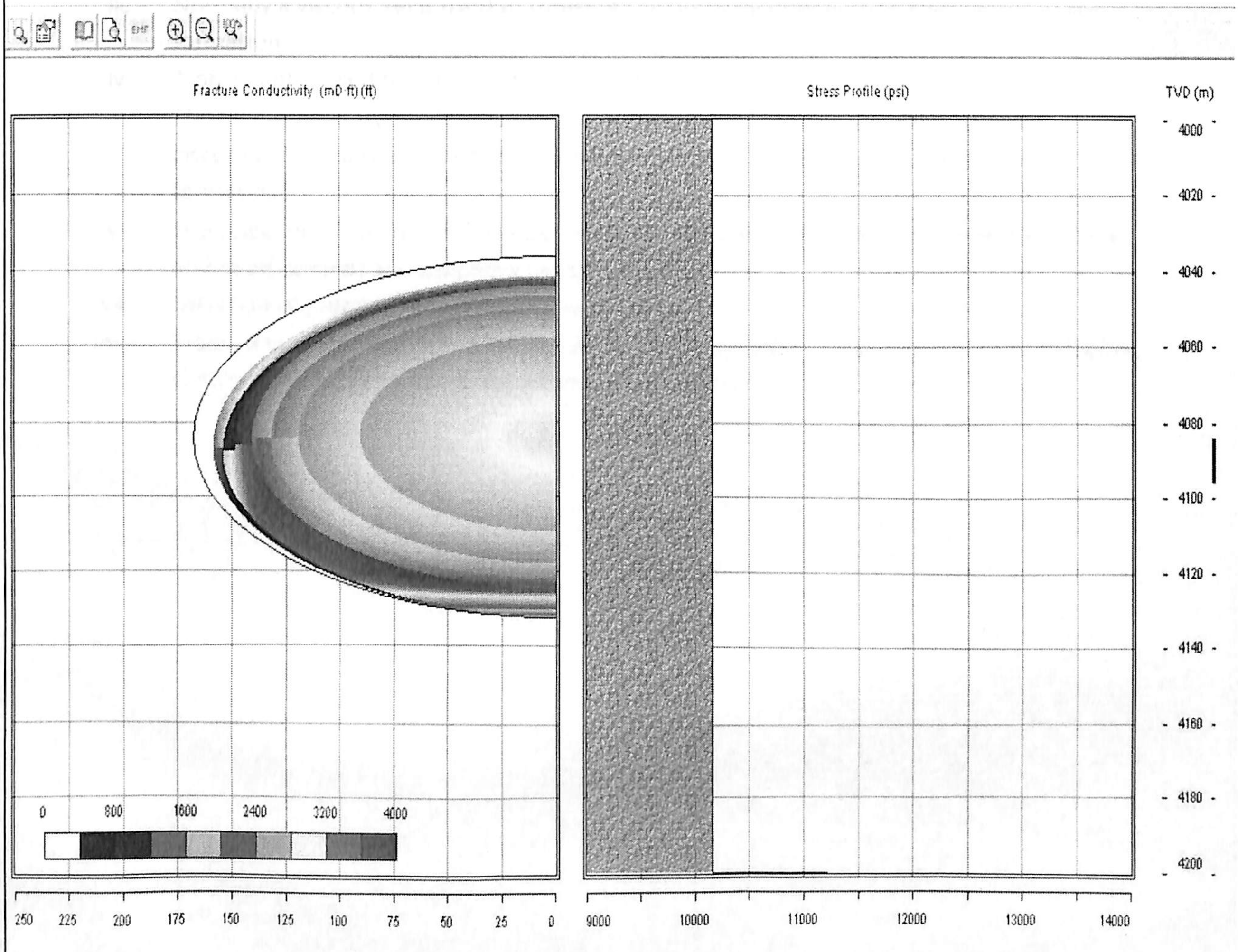

Total Fracture Height
Fracture Length
Width at Perforations
Time


Propped Upper Height
Total Proppant Height
Propped Lower Height
Time
Propped Length
Width at Perforations
Average Width

Various proppant concentration :



Proppant conductivity :



Conclusion

i. Hydraulic Fracturing is a well stimulation technique that is most suitable to wells in low and moderate permeability reservoirs that do not provide commercial production rates even though formation damages are removed by acidizing treatments.

ii. Hydraulic Fracturing is done by applying the pressure greater than the fracture pressure of the formation. The benefits of Hydraulic Fracturing is to increase the production by creating highly conductive flow channels which is done by changing flow pattern from radial to laminar.

iii. Normally a viscous gel is used to transmit the pressure energy from the surface to the formation.

iv. A proppant is used to keep the frac open after the completion of job.

v. The fluid used in Hydraulic Fracturing treatment should have the properties (high viscosity) to initiate the fracture as well as transport the proppant from the surface to the formation.

vi. The selection of fracture fluid depends on its reservoir parameters, completion methods and th equipment and proppant carrying capacity.

vii. Selection of proppant depends on the closure stress.

viii. Treatment design and optimization can be efficiently done using the Hydraulic Fracturing simulator and it depends on the economic parameters.

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