Successful Fracture Stimulation in Tight Gas Sands of Southeast New Mexico with Binary Foam

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Abstract

The subject matter of this paper will describe Binary foam fluids, their advantages and how they have been applied to increase production in various tight gas sands in Southeast New Mexico. The paper will include a discussion of the formations stimulated, production results, and typical treatments for tight gas sands. Furthermore, the paper will include comments on Binary foam design utilizing three dimensional fracture simulators and considerations for workover candidate selection.

Introduction

Binary foam fluids were first introduced to the industry as a patented fluid process in August, 1989[5]. Since that time hundreds of Binary foam fracture stimulations have been performed throughout the Continental United States. Previous studies by V.J. Pai, et.al [2] outline the benefits of fracture stimulating the Morrow and Atoka formations of S.E. New Mexico with Binary Foams. Since that time technology trends have lead to the application of Non-Foamed "Alcohol Systems". While these systems are excellent in their ability to limit water on formation, their ability to create true foam rheologies is limited.

The recent decline in crude oil prices has spurred activity in some natural gas producing intervals in S.E. New Mexico. New applications for Binary foam fluids have been identified and initial results are encouraging. During 1998 approximately 42 Binary foam fracture stimulations were successfully pumped in Lea, Eddy, and Chaves Counties. These stimulations were pumped in the Morrow, Atoka, Abo, Strawn and Eumont (Yates, Seven-River, Queens) formations.

Binary Foams

Binary foams are a combination of carbon dioxide and nitrogen dispersed in liquid and stabilized by a surfactant[1]. These surfactants are referred to as foamers. The liquid phase for foamed fracturing fluids is generally gelled water. The carbon dioxide and nitrogen contents can vary but they are typically as follows:

70Q Binary Foam = 50% CO_2 + 20% N_2
80Q Binary Foam = 50% CO_2 + 30% N_2

It should be noted that foams are typically between 60 and 85 quality, (quality refers to the percentage of gas in the system). When the foam qualities are below 60%, there is not enough gas to "foam" the fluid phase, thereby resulting in a loss of viscosity of the system. When foam qualities are above 85%, there is too much gas and not enough fluid to "foam" the system. Both effects result in a severe reduction in the viscosity of the system.

Foam qualities are classified under two categories – Mitchell quality or constant internal phase. Mitchell quality is defined as the ratio of the gas volume divided by the total volume of the foam. Sand is not a consideration in this definition. Constant internal phase is defined as the ratio of the gas volume plus the proppant volume divided by the total volume of the foamed slurry. Mitchell quality ignores the proppant, considering it inert, and constant internal phase calculates the proppant as a part of the entire foamed system.

Why Combine Carbon Dioxide and Nitrogen?

The Binary foam was first introduced in 1989 to compete with patented 53 to 90 quality carbon dioxide foams. Initial results showed much quicker cleanup times in comparison with straight carbon dioxide foamed jobs. Why does this occur? Nitrogen has a tendency to flow back more rapidly than carbon dioxide. This is due in part to the fact that nitrogen is not soluble in water or liquid hydrocarbons. On the other hand, carbon dioxide is highly soluble in water and liquid hydrocarbons. Carbon dioxide results in a more thorough clean up, but it is much slower. When both gases are combined in the same system, the result is a quicker and more complete clean up when compared to carbon dioxide foams without nitrogen. This effect has shown to be very important in obtaining good production results in various tight sandstone formations in Southeast New Mexico. The Morrow, Strawn, Atoka, Eumont and Abo formations show characteristics of severe fluid retention when stimulated. Whether this phenomenon is due to potentially undersaturated reservoirs or to capillary pressure effects in very low permeability zones is not known, but it is critical in stimulation design. Fluid retention results in a loss of effective permeability since stimulation fluids are not retrieved, thereby leaving gel polymers in the formation.

Another effect that occurs when carbon dioxide and nitrogen are combined in the same system is a reduction in friction pressure while pumping. This is illustrated in Figure 1 with a comparison between a binary foam and a straight carbon dioxide foam. While the difference is not dramatic, it can be significant when treating down smaller tubulars at greater depths.

The Foam Fluid Flow Loop

The foam fluid flow loop is a capillary tube viscometer used to measure the viscosity of foamed or energized fluids. There are essentially 9 elements in the foam loop[2]. The elements are mixing equipment, pumping equipment, crosslinker injection site, foam generator, heated 1000 ft. coil of 316 SS tubing, viscometer, measuring equipment, viewing cell, back pressure regulator, and data storage equipment. Figure 2 displays the flow loop and position of the elements listed. The process is listed in step by step format as follows:

1) The mixing equipment is used to prepare the base fluid. The base fluid can be water, polymer solution, various solutions of methanol, etc.
2) The base fluid is pumped through a mass flow meter to a crosslinker injection site using a triplex Cat pump. At this site, crosslinker can be injected into the base fluid using a duplex Thermoseparation pump.
3) After crosslinker injection, the fluid moves to the foam generator. Liquid carbon dioxide and/or nitrogen are pressured through a mass flow meter and into a foam generator where it contacts the base fluid/crosslinked fluid (bf/cf). The foam generator is a cross fitting rated to 6000 psig. Nitrogen and/or liquid carbon dioxide enter the foam generator at 90° angles to the bf/cf, carbon dioxide on one side, nitrogen on the other side (see diagram). The foam exit point is directly opposite the bf/cf entry point. Liquid carbon dioxide is pumped into the foam generator by a simplex pump using pulsation-damping equipment to maintain a constant flow rate. Nitrogen is regulated into the foam generator using a gas regulator attached to a 6000 psig nitrogen bottle.
4) The foam exits the foam generator and enters a 1000 ft. coil of 316 SS tubing that is submerged in an oil bath. The oil bath temperature can be controlled from 40 to 250°F. The time the foam is at temperature is based on the flow rate of the foam and the volume of the tubing. In most testing, the maximum time the fluid is at temperature is 25-30 minutes.
5) The foam enters the capillary tube viscometer after traveling through the 1000 feet of coiled tubing. Five different tube runs (different ID and tube length) with delta pressure transducers on each tube run and one mass flow meter/densimeter comprise the viscometer. With the viscometer filled with foam, 5 delta pressures are measured along with the mass flow rate and density of the foam. Based on tube geometry, mass flow rate, density of the foam, and delta pressure in each tube, a set of 5 shear stresses with their corresponding shear rates is calculated. This set of shear stresses and shear rates is then used to calculate the rheological indices n' and K.
6) After the foam exits the viscometer, it passes through a viewing cell where foam texture, bubble size, and foam stability information can be gathered.

7) The foam then exits to a waste tank through a back pressure regulator. The back pressure regulator is used to maintain a constant pressure on the viscometer.
8) All control schemes, measurements, calculations, and data storage functions are performed on a PC.

The foam fluid flow loop is used to determine the viscosity of various foams and identifies additives that are not compatible with foam systems. It can not be emphasized enough how important the flow loop is in enabling engineers to optimize the rheological properties of a foamed fluid system. Through the use of the flow loop, many products and additives have been identified that eliminate the viscosity of a foam system. The number of products that produce a negative effect on foam fluid viscosity is significant. Without adequate flow loop testing the estimate of foam viscosity is a guess at best.

Figure 3 shows the data produced from the flow loop for a 70Q Binary foam.

Binary Foam Fluid System Additives

Linear Binary Foams

The additives for a typical linear binary foam are as follows:

Gas Phase:

CO_2 – 50%
N_2 – 20 to 30%

It should be noted that carbon dioxide and nitrogen volumes can be adjusted to accommodate an internal phase of 35 to 50% carbon dioxide and 15 to 35% nitrogen.

Fluid Phase– 2% KCL:

1. Gelling Agent – 30 to 40 ppg CMHPG polymer or 16 – 25 ppg CMG polymer
2. Surfactant – 1 gpt
3. Surface Tension Reducer – 1 gpt
4. Foamer – 4 to 8 gpt (Varies based on percentage of methanol used)
5. Bacteria Control - 0.3 ppt
6. Gel Breaker - 0.25 to 1 gpt Enzyme Breaker (Varies based on BHST)
7. Gel Breaker – 1 ppt Encapsulated Oxidative Breaker
8. Methanol – 0 to 20% (As Needed)

Crosslinked Binary Foams

The additives for a typical crosslinked binary foam are as follows:

Gas Phase:

CO_2 – 50%
N2 – 20 to 30%

Fluid Phase– 2% KCL:

1. Gelling Agent – 30 to 40 ppg CMHPG polymer or 16 – 25 ppg CMG polymer
2. Surfactant – 1 gpt

3. Surface Tension Reducer – 1 gpt
4. Foamer – 4 to 8 gpt (Varies according to if and how much methanol is used)
5. Bacteria Control - .3 ppt
6. Gel Breaker - .25 to 1 gpt Enzyme Breaker (Varies according to BHT)
7. Gel Breaker – 1 ppt Encapsulated Breaker
8. Methanol – 0 to 20% (Discussion to follow)
9. Crosslinker - .75 gpt

A new generation of crosslinked fluids is available to the industry whereby a 16 to 20 ppt CMG polymer is used in place of the 30 to 40 ppt CMHPG polymer. This fluid generates more viscosity than the higher gel loadings even though it utilizes half of the polymer loading of the system. The crosslink time of this fluid can be delayed according to pipe time, without any detrimental effects to the viscosity of the system. This new polymer system when combined with a specialized crosslinker produces the only low pH delayed system available. This is important to Binary foams since they are low pH fluids due to the presence of carbon dioxide. Ph ranges from 3.4 to 3.9 have been recorded on the Foam Fluid Flow Loop. Figure 4 shows the increase of viscosities in the presence of this enhanced polymer technology utilizing CMG.

Applications of Linear Binary Foams vs. Crosslinked Binary Foams

Linear Binary foams should be primarily used in small, contained zones in which fracture length is critical. Linear foams will typically create lesser fracture heights and widths than crosslinked fluids, but typically create longer lengths. This fluid is used in single, low permeability zones, which exhibit well defined boundaries above and below the pay zone.

Crosslinked Binary foams should be used when fracturing large intervals or when fracturing multiple zones. This fluid will typically treat a greater amount of pay due to the higher viscosity of the system. Crosslinked foams seem to be more effective than linear foams when treating deep, high fracture gradient wells that have a history of high screen out ratios. Crosslinked fluids can be very advantageous when tubular restrictions reduce treating rates due to high friction pressures. The crosslinking of the foam (utilizing enhanced polymer technology) can be delayed to reduce friction pressure while the increased viscosity will obtain the greater fracture width needed to pump the job to completion. The higher viscosity of the crosslinked foam is essential in treating high leakoff zones or in wells that are naturally fractured.

Comparisons can be made between linear Binary foams and crosslinked Binary Foam by reviewing Figure 3 and Figure 4. Figure 3 illustrates the viscosity of a 70 quality Binary foam with a 40 pounds/gallons polymer loading. Figure 4 illustrates the viscosity of a 70 quality crosslinked Binary foam at various polymer loadings.

Methanol Usage

The inclusion of methanol in fracturing fluids has been in use for many years. Early use of methanol in fracturing fluids was included to take advantage of the low surface tension properties exhibited by pure methanol. Surface tension for methanol has been measured in the laboratory at 22.61 dynes/cm compared to 72.75 dynes/cm for water. While the surface tension of water can be reduced to very near that of methanol by adding surfactants, it may not remain at this low value throughout the clean-up period. Removal of surfactants through adsorption onto the formations and particularly clay particles can alter the surface tension properties of water base fluid. Methanol based fluid reduces the capillary pressure thereby improving the ease of flowback by maintaining a low interfacial tension with gas throughout the clean-up period[4].

The flowback enhancement properties of methanol are well documented. However, the use of methanol in Binary foam fluid systems is included not only for these flowback enhancement characteristics, but to also reduce the total amount of water present in the system. Flowback potential of these foam fluids can be greatly enhanced by limiting water on formation to address formations exhibiting potentially undersaturated characteristics or the capillary effects associated with very low formation permeability as previously mentioned.

Testing conducted on the flow loop has shown that methanol exhibits tendencies to destabilize foams as illustrated in figure 5. In figure 5 notice the decreased viscosity and scattered data points associated with 20% methanol. Figure 6 exhibits higher viscosity readings and stable data points with a methanol content of 10% by volume. Higher loadings than 10% may be utilized in Binary foams but foam quality must be adjusted to accommodate loadings up to 20%. The use of methanol greater than 25% by volume results in foams losing all enhanced viscosity and reducing it back to linear gel viscosities thereby decreasing their ability to effectively transport proppants. The following outline illustrates the percentages of methanol that can be used in the fluid phase of the system, and the subsequent quantity of gelled water that will be placed on formation.

70Q Binary Foams

Maximum Percentage of Methanol – 20%

Gases – 70% of the system
- N_2 – 20%
- CO_2 – 50%

Fluid – 30% of the system
- Gelled Water – 80% of the fluid phase
- Methanol – 20% of the fluid phase

Leaving 24% (by volume) Gelled Water on Formation

80Q Binary Foams

Maximum Percentage of Methanol – 15%

Gases – 80% of the system
- N_2 – 30%
- CO_2 – 50%

Fluid – 20% of the system
- Gelled Water – 85% of the fluid phase
- Methanol – 15% of the fluid phase

Leaving 17% (by volume) Gelled Water on Formation

Formations that have been successfully stimulated with the Binary Foam

Successful Binary foam treatments have been documented in most formations in Southeast New Mexico that can be classified as "Tight Gas Sands". Numerous successes utilizing Binary foam in the Morrow formation have been documented since 1990. Recently, Binary fluid systems have been applied in other tight gas sands that exhibit like geological characteristics.

The Abo reservoirs in Northern Chaves County consists of interbedded lenticular red sandstones and red siliciclastic shales. Thickness ranges from 400' at Pecos Slope west to 650' at Pecos Slope. Average porosity of productive sandstones is 12% - 14%. The minimum porosity for production is 9%. Porosity is mostly microporosity. Lenticular sandstones in the upper part of formation are productive. Average net pay is 30' ranging from 10' to more than 80'. Sandstones are red arkosic arenites (feldspar & quartz as primary grains). Hematite, clay (fibrous illite, chlorite), anhydrite, and ferroan dolomite are dominant intergranular cements. The formation is "tight" with the average insitu permeability being 0.0067 md.

The Atoka formations are developed in both fluvial deltaic and prograding strandline sandstones. Bank carbonate mounds in Southern Lea and Eddy Counties also contribute significantly to production. Sandstones are quartzose and are fine to course grained. Average porosities range from 2 – 16%, with an average of 10%. Permeabilities are in the 10's of millidarcies. Intergranular cement consists of silica overgrowths on quartz grains, kaolinite, and dolomite. Carbonate reservoirs exhibit porosities of 1-7% and are finely crystalline and fossiliferous. Vugular pores are common. Average thickness is about 300' and includes productive and non-productive rock.

The Strawn reservoirs are developed in both sandstones and carbonates. In Lea and Eddy counties, Strawn production is from localized, lenticular, biothermal shelf limestones (carbonate shoals and bars), which trend northeasterly. The gross carbonate interval is several hundred feet thick. Net pay may be as much as 220', but most commonly, net pay is 10' to 50' in thickness. Effective average porosities are 2% to 9%. Permeabilities may reach as high as 100 md; however, zones requiring fracture stimulation trend much lower.

The Eumont or Artesia group consists of three members: Queen formation, Seven Rivers formation and the Yates formation. The group varies in thickness from 130' to 900'. The Seven Rivers consists, principally of anhydrite and red mudstone. The Queen and Yates are composed dominantly of red mudstones and fine-grained silty sandstones. The sandstones/siltstones are tight (0.03 md), are quartzose, feldspatnic (usually 10-11% feldspar) and contain abundant carbonate (usually dolomite). fibrous illite, and chlorite – smectite (a mixed layer swelling clay).

The Morrow reservoir remains the most proven application for Binary foam. Through the years there has been considerable difficulty in stimulating the Morrow, because in most instances, potentials following treatments were less than those experienced on drill stem test. This has resulted in experimenting with many different type treatments. Over time Binary foams have proven to be one of the stimulation fluids of choice due to its inherit ability to enhance initial wellbore clean-up and load recovery. The success in the Morrow can be attributed to the assumption that the basic problem in the Morrow is not simply wellbore damage per se, but is suspected to be damage from fluid invasion altering the relative permeability. The Morrow formation is a medium to fine grained sandstone with major inclusions of feldspar, both plagioclase and K- feldspar. The quartz grains are cemented with quartz overgrowth and additionally by carbonate minerals. Clays average less than 5% by volume and can be comprised of kaolonite, illite and small percentages on smectite clays. Porosity may range from 4 – 15% with productive zones averaging greater than 8%. Permeability is variable and can range from 0.02 to 324 md with higher perm wells flowing naturally without stimulation.

The rule with the Morrow is variability. Bottom hole pressure varies just as widely and can range from 0.1 to 0.6 psi/ft. Lack of adequate reservoir characterization makes this one of the most difficult reservoirs to stimulate.

The similarity between these reservoirs is clear. As with all tight gas sands the most challenging aspect to stimulation design is reservoir variability.

To examine the results of Binary foam fracture treatments, a sample of wells from both the Morrow and Strawn formations were studied. Wells included in the sample were selected based on the availability of reliable pre and post fracture production. This sample included nine Morrow wells and seven Strawn wells . The Morrow wells included in the study produced at an average daily pre-fracture production rate of 392,000 scf/day. These same wells which were stimulated with Binary foam yielded a 3 month post-fracture average daily production rate of 1,275,000 scf/day. The seven Strawn wells examined. produced at an average pre-fracture production rate of 725,000 scf/day. After fracture stimulation with Binary foam, these same wells produced at a 3 month post-fracture average daily production rate of 1,816.250 scf/day. This sampling of wells responded with an approximate three-fold production increase. Wells from the Abo, Atoka and Eumont formations have provided substantial post-fracture production increases, but wells in this category were new completions; therefore no pre-fracture production was available.

The authors believe the most practical method of evaluating fracture treatment success is to compare production response pre-fracture vs. post-fracture. This method provides a true indication of fracture stimulation effectiveness for any given well.

Stimulation Candidates

Bottom hole pressure buildup tests are essential in determining fracture candidates. From these tests a calculated number for bottom hole pressure, permeability, and skin factor can be obtained. The first and most essential number is bottom hole pressure. If a well has a very low bottom hole pressure, the chances for significant production increase are minimal. But a "low or high" bottom hole pressure is relative for wells in the zones and geographical area. For example – a Morrow, Strawn, or Atoka well in southeast New Mexico with a bottom hole pressure of 1,500 psi would be considered low. For a well in the Abo in Chaves County, New Mexico, this pressure would be considered high. There is also a relationship for successful fracture treatments between bottom hole pressure and permeability. Wells with a low bottom hole pressure can be stimulated effectively if they have a relatively high permeability. Conversely, wells with low permeabilities can be effectively stimulated if they have high bottom hole pressures. Figure 7 shows a general relationship that can be made for successful stimulations for the Morrow, Strawn, and Atoka formations in Southeast New Mexico.

The next factor to consider is skin damage and how it occurs. Skin damage typically occurs due to a loss of drilling fluids into the formation of interest. The Morrow, Strawn, and Atoka sands typically lie between tight bounding layers that act as barriers to fracture height growth. The stress layers in these sandstones are usually much lower than the surrounding layers. When the wells are drilled and the hydrostatic pressure of the drilling fluids exceeds the parting pressure of the rock, the result is a long thin fracture through these zones with a deposit of drilling mud throughout. These wells exhibit a high skin value on pressure buildup analysis. A well designed fracture stimulation is necessary to extend past this damage.

Another tool that can be used when determining fracture candidates for older wells are P/Z plots. Along with bottom hole pressure and skin factors, these plots give an estimated volume of gas left in the reservoir. Wells showing appreciable amounts of gas in the reservoir along with reasonable values for bottom hole pressure and permeability make excellent fracture stimulation candidates.

Another factor to consider is the amount of production after the well has been broken down. While some formations show no correlation between post fracture production and initial production after break down, others do. It has been observed that in the Morrow, Strawn and Atoka, wells that produce below 150 MSCF/D after breakdown, typically show erratic results when fracture stimulated. This value can be used as a general rule of thumb in determining successful fracture candidates.

Design Considerations and Computer Modeling

All jobs are designed according to bottom hole treating conditions. Foam rates, qualities, and sand densities are different at surface conditions than at bottom hole conditions. The carbon dioxide rate is kept constant. This allows for all rate changes to be made with nitrogen and slurry rates only.

It is highly recommended that a nitrogen pump hold a constant pressure on the carbon dioxide vessel. As carbon dioxide is withdrawn from the vessel, the pressure decreases and the density of the carbon dioxide increases. The result is an increase in the friction pressure of the carbon dioxide. This increase in pressure is many times misinterpreted as the beginnings of a screen out. Holding 250 to 300 psi on the carbon dioxide vessel will eliminate any pressure increase due to a density change in the carbon dioxide vessel.

The flow back period after the fracture treatment is important to achieve the best results possible for the well. It is recommended that the wells be flowed back immediately after all fluids break. This will allow for the best clean up possible. If wells are shut in for too long, large amounts of the gases can bleed into the formation and will be ineffective in cleaning up the fracturing fluids. Table 1 gives the recommended choke sizes versus wellhead pressure and tubular size. This table is a recommendation and choke sizes should be adjusted in an attempt to maximize fluid removal.

Computer fracture modeling is an essential tool that should be used to model almost all fracture treatments. Although not perfect, this tool helps to eliminate the guesswork involved in fracture design. It is the authors' opinion that a 3-D conventional fracture model seems to match tagging and temperature profiles better than other models. The 3-D conventional fracture model on Fracpro has been used with great success. A stress profile – using Poisson's Ratio - is created from either sonic data or from the gamma ray. Sonic data is much more accurate for stress determination, but it involves higher costs due to the logging suite that has to be run. An effective porosity is calculated from the neutron/density log and the gamma ray. A permeability profile is then obtained from the effective porosity and a calculated volume for bulk volume of irreducible water. The stress layers, permeability profile, dynamic modulus and Poisson's ratio are then input into the fracture model. Other inputs are as follows: perforation depth, number of perforations, perforation size, tubular depth, tubular size, reservoir temperature, type of fracture fluid, proppant type, and pump schedule. Treatments are then simulated using the rheology properties for the fluid of choice at the expected pump rate. The model will give indications of screenouts, fracture heights, fracture lengths, propped widths, and amount of proppant per square foot. Once the model has been set up, various job types can then be run to maximize well pay out versus job cost.

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Table 1 - Recommended Choke Settings for Flow-Back of Foamed Fluids

Pipe Size	0-500	500-1000	1000-1500	1500-2000	2000-2500	2500-3000	3000-4000	3000-4000
2 3.8" 4.7#	20/64	18/64	16/64	14/64	14/64	12/64	12/64	8/64
2 7/8" 6.5#	24/64	22/64	18/64	18/64	16/64	16/64	14/64	8/64
3 ½" 9.3#	30/64	26/64	22/64	20/64	20/64	18/64	18/64	10/64
4 ½" 11.6#	40/64	34/64	30/64	28/64	26/64	24/64	24/64	10/64
5 ½" 15.5#	48/64	40/64	36/64	34/64	32/64	30/64	28/64	12/64
7" 23#	60/64	52/64	46/64	42/64	40/64	38/64	36/64	14/64

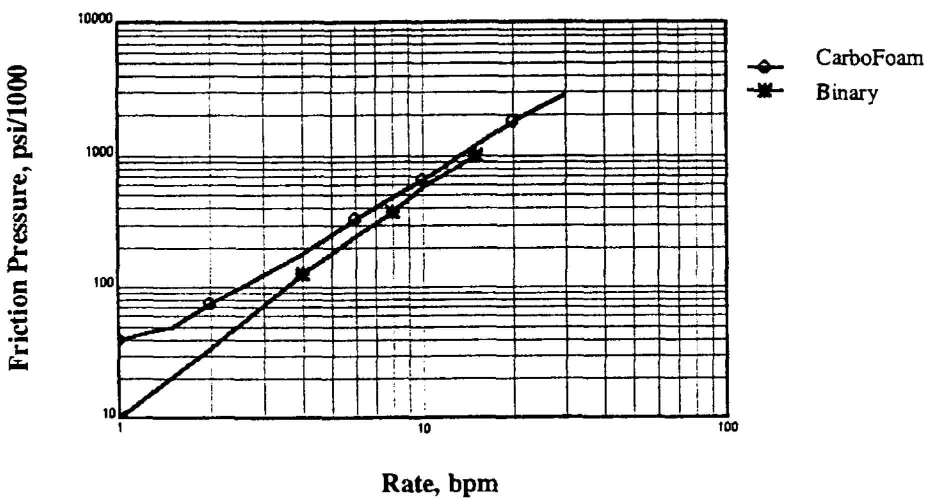

Figure 1 - Friction Pressure in 2 3/8" Tubing
CarboFoam vs. Binary

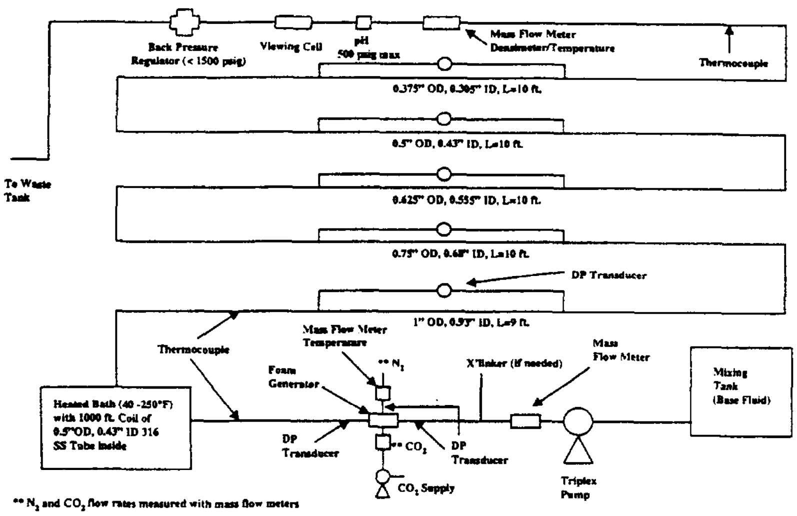

Figure 2 - Foam Rheology Loop
TTC

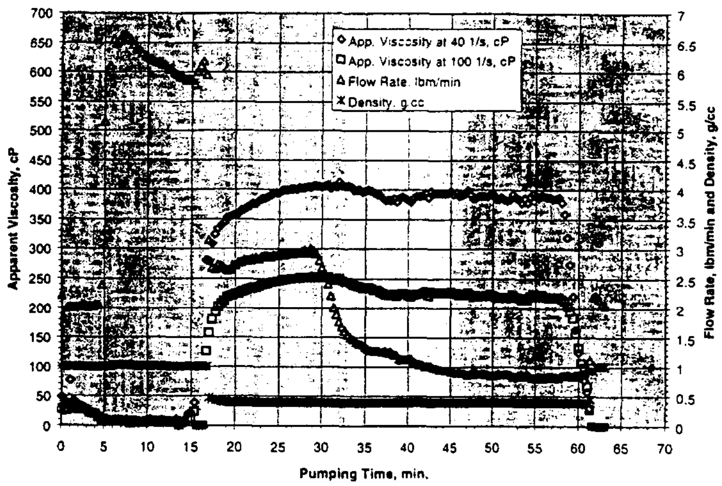

Figure 3 - 70 Quality Linear Binary Foam

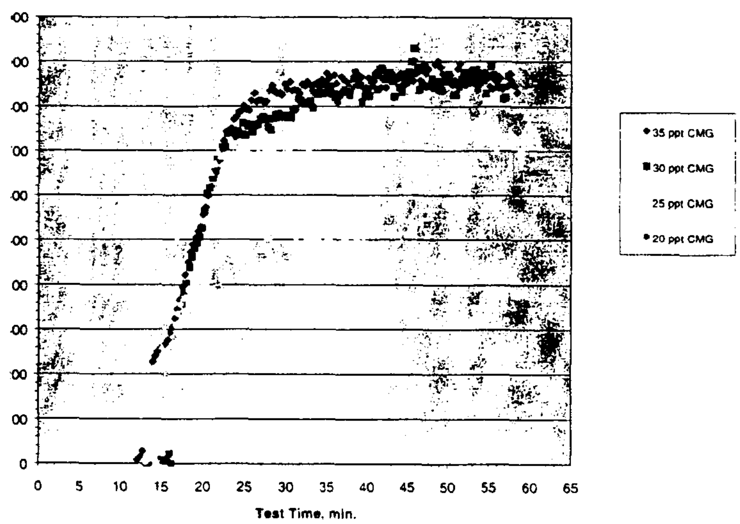

Figure 4 - Apparent Viscosity of 70 Quality Crosslinked Binary Foams During Test Runs w/CMG Loadings from 35 to 20 ppg

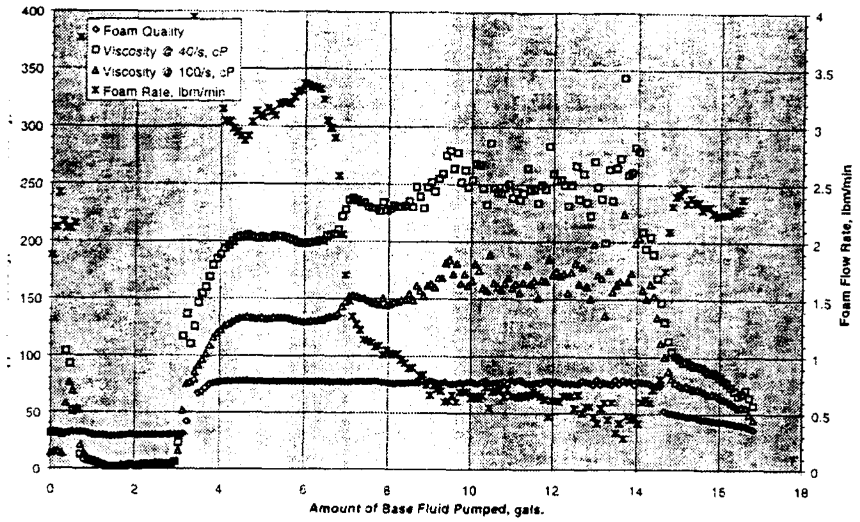

Figure 5 - 80Q Linear Binary Foam (50% Carbon Dioxide and 30% Nitrogen) Containing 20% Methonal

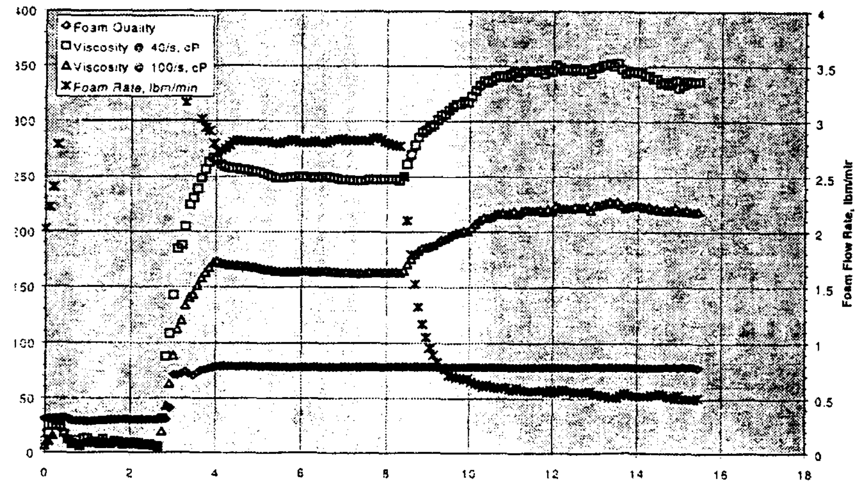

Figure 6 - 80Q Linear Binary Foam (50% Carbon Dioxide and 30% Nitrogen) Containing 10% Methonal

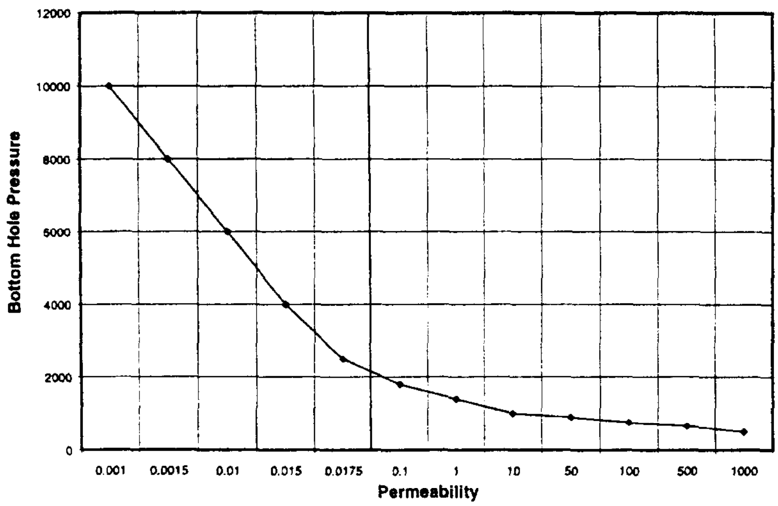

Figure 7 - Fracture Candidate Determination