A REVIEW OF NEW TECHNIQUES AND METHODS OF COMPLETING THE DELAWARE FORMATION OF S.E. NEW MEXICO

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ABSTRACT

With improved oil prices the Delaware formation of S.E. New Mexico has become a hot bed of activity since early 1990. The paper presents background information such as lithology, formation rock characteristics, X-Ray Diffraction and SEM analysis. Completion practices and perforation programs are reviewed for nine different fields along with analysis of different stimulation practices. The paper also reviews stimulation fluids, volumes, injection rates, types of proppant used and fracture geometries to provide an optimum completion program.

INTRODUCTION

Although the Delaware formation of Southeast New Mexico has been explored and investigated since early to mid seventies, it is only since the late eighties and early nineties that this formation has seen a very high level of drilling and completion activity. The Delaware formation which has a thickness in excess of 3000 ft. in some areas[1] consists of the Bell Canyon, the Cherry Canyon and the Brushy Canyon. The present study focuses on only the Cherry Canyon and the Brushy Canyon. Greater emphasis is placed on the Brushy Canyon which is more prolific in most instances.

The Brushy Canyon sands predominate the lower Delaware Mountain Group and consists of layers of sand, shale and some thin layers of dolomite. Depending on the area, the Brushy Canyon interval varies in thickness and exhibits a lenticular framework with individual stringers varying in oil and water saturation. The close proximity of water bearing sands, both above and below the oil bearing sands, poses some interesting completion challenges. This problem has been alleviated using different fracturing techniques.

The Delaware formation in most areas consists of over 80% quartz[1] and almost always requires to be hydraulically fractured to be economically lucrative. For the purposes of this study we reviewed completion practices of 26 different operators in S.E. New Mexico from January 1, 1988 to May 31, 1993. The Delaware wells in the field are drilled generally on 40 acre spacing. Production is highly variable with production after fracturing varying from 30 BOPD to 187 BOPD (top allowable) and water varying from none to 300 BOPD. Gas production ranges where applicable from 50 to 400 MCFPD. Many of the wells, especially in the Sand Dunes, E. Loving and the Livingston Ridge area produce flowing.

Generally, the lack of competent barriers to fracture height growth results in vertical fractures in excess of 200 ft and these interconnect several productive "stringers" as well as the water saturated sands. Methods have been devised to reduce this problem[2]. Lithology of some of the fields has been presented to help in designing completion fluid formulations.

PURPOSE AND SCOPE OF THE STUDY

One of the dangers in studying the Delaware formation, is the tendency of over generalizing and arriving at a single neat completion strategy that applies to all the fields. It should be noted that our experience shows that the Delaware like most formations of the Permian Basin does not lend itself to a simple unique completion strategy. In our study we reviewed 9 fairly established fields in Eddy and Lea Counties of New Mexico. The fields studied are Avalon, Burton Flats, Cat Claw Draw, E. Loving, Livingston Ridge, Lusk, Parkway, Poker Lake and Sand Dunes. These fields are presented in Table 1 and marked in Figure 1. The purpose of this paper was to study these different fields and find the commonality that links them and the differences that separate them. Finally, based on this understanding evolve a completion strategy that is simple, cost effective and fairly general to be applicable in most areas of Southeast New Mexico.

Since majority of the 26 operators we studied prefer to "tight hole" pertinent information, we have in this paper only presented techniques and broad principles used in successful completions without divulging specific log, perforated interval and production information in a given area unique to any individual operator. Most figures are slightly modified to maintain confidentiality.

From Table 2 it can be seen that from January 1, 1988, to May 31, 1993, we reviewed treatments on 328 wells. Of these wells 73.7% or 241 wells were fracture stimulated. Of the wells fractured, 79.7% or 192 wells were fractured using borate crosslinked water based gel. Since 1990, the popularity of the borate gels has further increased with over 95% of the operators opting for the use of gels consisting of 30 to 35 pounds of guar per 1,000 gal of water crosslinked with borate ions.

For the purposes of this study, we took a random sample of 51 fracture treatments of the 241 wells fracture treated for detailed analysis. All the 9 fields studied were represented in the sample.

FORMATION AND RESERVOIR PROPERTIES

The formation and the reservoir properties were averaged from the information obtained from logs, treatment data and operators on the 51 fracture treatments sampled. The average bottom hole temperatures, bottom hole fracturing pressures and the appropriate gradients are tabulated in Table 3. The Cherry Canyon fracture gradient ranged from 0.57 to 0.70 psi/ft with the average being 0.61 psi/ft. The lower Brushy Canyon fracture gradient ranged from 0.49 psi/ft to 0.61 psi/ft with the average being 0.53 psi/ft. Similarly, the upper Brushy Canyon average fracture gradient was calculated to be 0.55 psi/ft. The average temperature gradient for the entire Cherry Canyon and Brushy Canyon interval based on log recorded temperature was calculated at 0.77° F/100 ft with an assumed surface temperature of 74° F. Reservoir properties obtained from logs and core data are presented in Table 4.

FORMATION LITHOLOGY

The formation lithology and mineral content is fairly consistent and is summarized for 3 representative fields namely the Burton Flats, the Livingston Ridge and the Parkway. These 3 fields closely represent the Delaware formation (Brushy Canyon) in S.E. New Mexico.

The following mineralogical analyses were performed on the cores available:

1. X-Ray Diffraction (mineral content)
2. Scanning Electron Microscopy
3. Acid solubility

The objective of this analysis was to define the rock framework mineralogy, clay content, cementing materials and types of porosity present in the sample and based on this to make an appropriate recommendation regarding completion fluid formulation and type. The Scanning Electron Micrographs are presented in Figure 2 through Figure 5. The average reservoir properties are presented in Table 4 and the mineral content from X-Ray Diffraction is presented in Table 5.

The Parkway Field

The samples from this field were by and large very find grained sandstones to very coarse grained siltstones that are cemented with predominantly quartz overgrowth. Chlorite which is the cementing material along with minor illite form extensive grain coating networks with associated microporosity. Pyrite framboids are found in the pore space.

Mineral content and their relative percentage are shown in Table 5. The sample exhibited a very slow reaction with acid and a significant yellow staining indicative of iron content. No significant visible swelling or sloughing effect were noticed when immersed in de-ionized water.

SEM/EDS analysis of the sample revealed framework of quartz and feldspar grains cemented by chlorite clays and quartz overgrowths. Generally, samples show a well-sorted fine grained sandstone with fair intergranular porosity, with open pores visible between grains. In addition, samples showed extensive network of grain-coating authigenic clays that are precipitated on grain and cement surfaces. Due to extensive network of grain coating clays, a major portion of porosity is microporosity associated with the clays. The predominant clay is chlorite, with minor illite also present.

The presence of the minerals mentioned and the framework of the rock pose three completion problems - acid sensitivity, fines migration and fluid retention in microporosity.

The Burton Flat Field

Both the Cherry Canyon and the Brushy Canyon samples were analyzed. The Cherry Canyon samples represented bioturbated siltstones containing large amounts of clay/shale particles not tied up in shale laminations but dispersed throughout the sample, probably near the time of deposition. The Brushy Canyon displayed relatively clean siltstone layers separated by very fine clay rich laminations. The average gas permeability for the Cherry Canyon was 1.57 md and for the Brushy Canyon was 3.25 md. The significant difference between the two zones is probably due to the Brushy Canyon siltstone being much "cleaner". The average grain density of the siltstone was determined to be 2.66.

The samples showed few visible swelling effects from water and a very slow reaction rate with 15% HCl acid. The acid did produce yellow staining indicative of iron but caused little disaggregation of the sample. The results of XRD are presented in Table 5.

The SEM analysis confirms the samples as feldspar rich quartzose siltstones. Grain sizes range from lower very fine grained sand to mostly silt. Framework appears to be cemented with dolomite, clays and minor quartz overgrowths. Authigenic precipitates (after initial deposition) include dolomite, anhydrite, pyrite, quartz microcrystals and clays. Intergranular porosity is generally fair to poor, due to extensive clay recrystallization and authigenic mineral deposition. A significant part of total porosity is microporosity associated with authigenic minerals. The clays observed include chlorite, some chlorite/smectite and pore bridging "hairy" illites.

Potential completion problems are acid and fresh water sensitivity, fines migration and fluid retention in microporosity.

The Livingston Ridge Field

The formation is a feldspathic sandstone of fairly uniform composition. The average mineralogical content from X-Ray Diffraction is presented in Table 5. Cementing material consists of calcite, dolomite, ankerite, secondary quartz and clays such as chlorite, illite and some mixed layer illite/montmorillonite. Potential completion problems are similar to those mentioned in the Parkway and the Burton Flats Field.

COMPLETION PROCEDURE

Completion procedure for the Delaware comprises of four aspects which can be generalized for each of the fields. Although mentioned earlier, generalizing a completion procedure for the entire S.E. New Mexico (Eddy and Lea Counties) is difficult, some consolidated broad completion strategy can be arrived at using sound engineering principles and the common properties that link these fields.

The following four aspects were considered in designing the completion procedure.

1. Interval and zone selection
2. Perforating scheme
3. Acidizing, fracturing fluid and proppant selection
4. Fracturing method and hydraulics

Our study showed that some of the common properties that link these fields are the rock properties, lithology, lenticular and laminated nature of the formation, low fracture gradients, absence of significant barriers and no major stress contrasts between the interval to be treated and the boundaries. Due to low stress contrasts and fracture gradients it can be conjectured that frac treatments produce tall vertical fractures that interconnect the oil producing stringers and the wet stringers. The other commonality in these fields is some post frac sand production and the high probability (73%) of requiring to fracture stimulate in order to be commercial.

Interval & Zone Selection

We studied several logs from the 51 sample wells, a typical lower Brushy Canyon, Gamma Ray porosity log is shown in Figure 6. The entire productive Delaware interval comprising of the Cherry Canyon the lower and the upper Brushy Canyon in many areas of S.E. New Mexico is over 3,000 feet thick. For the purposes of this analysis we focused on the Brushy Canyon which broadly speaking can be classified into the lower and the upper Brushy Canyon.

Each of the fields we studied has definite producing intervals. The typical perforated interval for each of the fields studied is summarized in Table 1. It should be noted that the perforated intervals shown are not specific to any one operator but rather a general average for the particular field.

In general, our study shows that the deeper part of the lower Brushy Canyon is more prolific and less water bearing. Additionally, productivity tests indicate, that in general, fields such as Parkway, Avalon and Burton Flats are less prolific and tend to produce more water. The Brushy Draw area, about 5 miles south of the city of Carlsbad, shows a proclivity for excessive water production from the lower part of the Lower Brushy Canyon.

To reduce water production, the water producing portion of the interval should be determined by offset well testing and not perforated. Most of the fields studied exhibited 4 to as many as 12 distinct zones or intervals which could be isolated and treated separately. Our study showed that such fine tuning or "micro-management" of the wellbore is not necessary and in some instances can be detrimental due to loss of control during the stimulation operation.

Based on the 51 sampled frac treatments, for purposes of completing, the Delaware should be divided into no more than 3 zones. Generally speaking, in the fields studied not more than 2 zones were completed per wellbore. Acidizing zones can be restricted to 100 ft to 150 ft per treatment. Each completion involving a fracture treatment should be, where possible, restricted to no less than 100 ft and no more than 300 ft. The reasoning for this zonal restriction is due to the formation's proclivity for excessive fracture height growth and "communication" between individual intervals. This aspect will be further discussed under "Fracturing Methods and Hydraulics".

Perforating Scheme

The perforating scheme which includes, the number, the size, the depth of penetration, the phasing, the density and the location of perforations, is very critical to the ultimate success of the Delaware formation completions. This fact was supported based on our work on the sampled wells. From our experience in Southeast New Mexico, the design of perforating scheme can be used to achieve the following four objectives.

1. Control fracture height
2. Provide frac fluid entry and selectivity
3. Alleviate proppant flowback problems
4. Reduction in horsepower cost

Experience both in the Cherry and the Brushy Canyon supported by FracHite logs and post fracture Radio activity surveys indicates a tendency for excessive fracture height growth. Examples of FracHite log and RA survey are presented in Figure 7 and Figure 11. As can be seen from FracHite log there are no significant barriers to fracture height growth and no major stress contrasts within the interval to be treated. From the example FracHite log (Figure 7) on E. Loving Field well, it can be seen that maximum stress contrast between the interval and the upper and lower boundaries is approximately 300 psi. If the net pressure increase during the fracturing operation is kept below 300 psi, the fracture height could be contained from approximately 6,150 ft to 6,275 ft. RA tag surveys routinely indicate fracture heights between 150 ft to 300 ft as shown in Figure 11. Based on this finding, it is prudent to assume that the fracture will cover the entire producing interval of 150 feet to 300 feet even from a small "cluster" of perforations. Further, there is no indication limited entry fracturing is required, since no significant stress contrasts exist within the producing interval.

To control fracture height growth we recommended in our example wells, cluster perforating method. This method involves perforating a 10 feet to 20 feet high porosity interval in the approximate center of the producing interval. An example of this method is presented in Figure 7 where we recommended 4 SPF - 90° phasing from 6,190 ft to 6,200 ft. A previous study[3] has shown higher performance using 60° or 90° phasing as opposed to 0° or 180° phasing. Since limited entry was not critical 4 SPF perforation density was selected.

In larger gross intervals (greater than 200') as shown in Figure 6, two sets or clusters of perforations are picked. In this lower Brushy Canyon example, we suggested two sets of perforations from 7760' to 7772' and 7830' to 7842' with 4 SPF - 90° phasing. The use of this perforating technique, it is theorized, allows for radial frac growth and limits vertical fracture height growth by focusing the frac energy at the perforation set or cluster (or two clusters) in the center of the producing interval. If the entire zone is blanket perforated, the proclivity for vertical fracture height growth will be enhanced due to greater pressure being applied to both the upper and the lower boundaries due to close proximity of the perforations. Therefore the lower southeast part of Eddy county, where the lower Brushy Canyon is prolific and about 200 ft to 250 ft thick - from approximately 7,700 ft to 7950 ft - as presented in Figure 6, we recommend a set of perforations from approximately 7,760 ft to 7772 ft and another set from 7,830 ft to 7,842 ft. The upper set is referred to as zone "A" and the lower set is referred to as zone "B". We recommend that each set be shot 4 SPF with 90° phasing.

This method of having two sets of perforations provides the operator with the ability to mechanically isolate, acidize and test both zones for oil and water production as well as obtain individual frac pressures. If both perforation sets satisfy production and frac pressure criteria, they can be fraced together, if not only a single zone should be fractured. This perforation technique will provide adequate frac fluid and proppant entry as the fracture will cover the entire 250 ft producing interval. This finding was further supported with 3-D frac modeling using Meyers model as shown later.

The cluster perforating method, based on post frac Prism™ or RA survey logs, provided adequate frac fluid and proppant entry throughout the gross producing interval. Post frac proppant flowback which has been a problem in the Delaware wells that were fractured through blanket perforated casing, can be controlled or alleviated using cluster perforating. We reviewed 22 cluster perforated wells that were fractured. Of these only three wells had proppant flowback problems reported by the operators two weeks after the treatment. It should be noted, that these treatments also included curable resin coated sand at the tailend of the frac, which could have helped alleviate the proppant flowback.

Increased perforation density also helped in reducing surface treating pressure by lowering perforation friction on an average of 200 psi. Reduction in pressure lowered hydraulic horsepower costs between $500 to $750 per treatment in the fracs we reviewed.

Acidizing, Fracturing Fluid and Proppant Selection

The formation characteristics based on lithology and mineral content indicate following areas of concern

- Acid and non-brine sensitivity
- Fines Migration, and
- Fluid retention due to microporosity

All completion fluids should be designed with the above mentioned criteria in mind. The fluid formulations we have presented here were used on all 51 sample wells and have by and large showed no detrimental effects such as water or emulsion blocks, formation damage and fluid retention as indicated by post treatment productivity and recovered fluid analysis.

Perforations opening or "breakdown" was accomplished with a weaker 7-1/2% HCl acid containing per 1,000 gal, 10 gal iron chelating agent, 1 gal corrosion inhibitor, 1 gal strong sandstone water wetting surfactant, 2 gal non-emulsifier and 1/2 gal clay stabilizer. It should be noted, that the formations acid sensitivity due in part to presence of cementing chlorite clays precludes the use of stronger 15% or 20% HCl acid.

Typically, we used 750 to 1,500 gal of breakdown fluid since the purpose of breakdown was to remove near wellbore damage caused by drilling fluids, cement and perforation debris and not provide major stimulation. We suggested the use of 50% excess ball sealers and a breakdown injection rate of 2 to 3 BPM. Almost always, the wells were flown back or swabbed after acidizing for removal of acid reaction by products and for testing well productivity.

Our study indicated that 73.7% of the wells were candidates for fracturing. Non-fracturing candidates were either sufficiently productive or produced an excess amount of water. Fracturing fluids used consisted of borate and titanate crosslinked water based gels, N_2 foam and linear water based gels. The percentage usage of these fluid is shown in Table 2.

Since 1990 the popularity of borate crosslinked fluids has been 95% or better. Of the 51 wells sampled only two were non-borate crosslinked gels. Based on our core study we recommend the following gel formulation. The base fluid should be 2% KCl or equivalent water containing per 1,000 gal, 25 to 35 lb of refined guar, crosslinker, crosslink delayer, fluid loss (diesel 3-5%) optional, 1 gal non-emulsifier. Bactericide is used as required. Gel degradant or breaker is based on our database for the area and gel breaker testing on location as required. Most operators prefer 2 to 3 hours for fracturing gel break time. Quality assurance with respects to fluids, breakers and other additives is routinely performed on location. The rationale for tailing in with high pH enzyme breakers is due to ineffectiveness of oxidizing breakers to perform rapidly in environments below 125° F without the addition of special catalysts. The rapid gel break requirement of 2 to 3 hours makes it imperative to use high pH enzymes in the later stages of the treatment when the fracture environment is cooled down by the frac fluid. Our study, also indicated that the use of thinner gels 25 to 30 lb guar in conjunction with delayed breakers provided less proppant pack damage due to gel filtercake thereby affording better long term productivity.

In the 51 wells studied we noted the following proppant usage profile. Twelve wells were fractured with 20-40 mesh Brady sand, 39 wells were fractured with 20-40 or 16-30 mesh Ottawa sand and 27 wells were fractured with a tail-in of 16-30 mesh or 20-40 mesh curable resin coated sand and an activator. The rationale for tailing-in with the curable resin coated sand was to alleviate proppant flowback problem. Of the eight post frac proppant flowback problems reported by operators, only two were fraced using curable resin coated sand and 6 were fraced without any resin coated sand. It should be noted, however, that proppant flowback control was also achieved by changing perforation method from blanket to cluster perforating. The closure stress in a typical Delaware formation varies from 2,500 psi to about 4,000 psi, therefore, high strength crush resistant proppant usage is not deemed necessary.

An example frac treatment pumped in the lower Brushy Canyon, in the Sand Dunes field perforated from 7,830' to 7,850' consists of 30,000 gal of 35 lb guar gel crosslinked with borate and 90,000 lb of proppant pumped at 15 BPM. The proppant pumped is 70,000 lb of 20-40 mesh Ottawa sand and tailend of 20,000 lb of 16-30 mesh curable resin coated sand (RCS) scheduled as follows:

Pump 13,000 gal as pad
Pump 4,500 gal with 2 ppg 20-40 sand
Pump 4,000 gal with 4 ppg 20-40 sand
Pump 3,500 gal with 6 ppg 20-40 sand
Pump 3,000 gal with 8 ppg 20-40 sand
Pump 2,000 gal with 10 ppg 16-30 curable RCS

Assuming a fracture height of 150 ft the above treatment based on our Perkins & Kern model produced a frac length of about 550 ft and a propped length of 350 ft. The reservoir data from Table 4 and Table 5 and fluid data from Table 6 was used in the computer model to arrive at the frac length. If the entire Brushy Canyon is fractured, the typical fracture height would be estimated at 300 ft and the treatment would be approximately 60,000 gal of borate crosslinked gel and 150,000 lb of 20-40 Ottawa sand and 40,000 lb 16-30 curable resin coated sand pumped at 25 to 35 BPM. Although, the proppant is stair stepped in the above case study, most operators prefer to "ramp" the proppant as shown in Figure 9.

Fracturing Methods and Hydraulics

In our study of 51 frac treatments we observed three distinct fracturing techniques. Of the 51 treatments, 15 were large volume and high injection rate fracs, 10 were "pipeline" fracs[2] and 26 were low volume and low rate fracs. The low rate and volume treatments were 7,000 to 20,000 gal 25 to 35 lb borate crosslinked gel and 20,000 to 40,000 lb proppant scheduled from 2 to 8 ppg and injected at 6 to 10 BPM. The large volume and rate fracs were 30,000 to 60,000 gal 25 to 35 lb borate crosslinked gel and 100,000 lb to 250,000 lb proppant scheduled from 2 to 10 ppg and injected at 25 to 35 BPM. Both these processes used 40% pad and had tail in of 10,000 lb to 50,000 lb of curable RCS. Our study showed both processes had varying degree of success.

The "pipeline" frac[2] which has had a very good success ratio in the southeastern part of Eddy county is exclusively used by at least three operators. The process and its results are outlined in Reference 2. Basically, "pipeline" fracturing consists of pumping about 70 to 80% thick viscous pad (35# crosslinked borate) followed by 20 to 30% 35 lb linear gel with proppant scheduled rapidly from 2.5 to 10 ppg. Typically, these treatments were pumped between 25 to 35 BPM. We did not model this design and based on area operators, this process has produced excellent results in and around Sand Dunes and Poker Lake area. In other areas the results were mixed and not conclusive.

From the study of the above treatments, it is felt that fracturing technique and hydraulics is critical to the overall success of the Delaware completion in S.E. New Mexico. As indicated earlier, field experience based on post frac temperature and RA surveys, Nolte plots (log-log plot of net pressure versus time at constant injection rate), FracHite™ and Gamma Ray-Porosity log shows no significant barriers to vertical fracture height growth. This fact is further supported by low calculated fracture gradients (less than 0.7 psi/ft) on all the sample wells, indicating a tendency towards vertical fracturing.

Nolte plot (Figure 8) on the E. Loving Field well which was fractured through perforations from 6,190 ft to 6,200 ft at 8 BPM showed a negative slope indicating unlimited height growth[4]. Of the 22 Nolte plots we reviewed in the various fields, 16 showed negative slopes, 4 showed almost zero slopes and only 2 showed short duration positive slopes. This data supports the tendency of these formations towards large fracture height growth. Similarly, FracHite logs in the Burton Flats, the E. Loving, the Herradura Bend, the Livingston Ridge and the Parkway fields showed no major stress contrasts within the producing interval. Also, in all these fields the maximum stress contrast between the producing interval and the upper and lower boundaries ranged between 300 to 500 psi. These facts strongly support the idea that even at low injection rates without using limited entry technique, hydraulic fractures will cover the entire 150 ft to 250 ft producing gross porosity when treated through either a single or a double 10 ft-15 ft cluster of perforations in the approximate center porosity. Post frac surveys in the Sand Dunes, the E. Loving and the Parkway field confirmed this hypothesis. Therefore, injection rate and perforation number and density are not critical to the fracture to cover the entire pay zone.

Due to low frac gradients (0.49 to 0.61 psi/ft) many of the frac treatments when pumped via casing showed zero surface treating pressure during stages of high proppant concentration. Fracturing without a positive surface treating pressure poses problems relating to monitoring and control, hence it was decided to treat via tubing. Fracturing via tubing affords sufficient friction thus providing a positive surface treating pressure. Additionally, to monitor increases in net pressure without having to estimate friction pressure the treatments were designed to pump via tubing which was run open ended and the annular pressure was continuously monitored with an inline transducer. The schematic for this process or control frac is presented in Figure 10. During the fracturing operation the increases in annular pressure are maintained below 300 to 400 psi. This technique provides for prevention of excessive fracture height growth.

Figure 11 is a presentation of a post frac RA survey (Prism-Spectral log) for the Brushy Canyon in the Pure Gold area. The subject well was perforated 7,965 ft to 8,022 ft (Zone A) and 8,110 ft to 8,140 ft (Zone B). The two zones were isolated and fractured individually at 10 BPM using a RBP. The Zone B frac sand was tagged with Iridium 192 and the Zone A frac sand was tagged using Scandium 46. The survey indicates that the two zones have communicated, providing further support that the Delaware zones tend to produce excessive vertical fracture growth.

The frac treatments were designed to be force closed. Of the total 241 frac treatments reviewed, 106 were forced closed. We also recommended that the wells be flowed back within three hours of fracturing completion. By and large operators that flowed back either immediately or within three hours of completion of fracturing in the same general area showed better qualitative productivity possible due to reduced filtercake and proppant conductivity damage. The use of curable resin coated sand dictates that the well be shut-in for about three hours or more to allow for the resin coated sand to cure or bond.

Meyers' model was used in conjunction with FracHite log to study and simulate fracture height growth. The results of this study is presented in Figure 12 through Figure 14. The Meyers' 3-D fracture model was run on a Brushy Canyon well in the E. Loving Field that was perforated from 6,190 ft to 6,200 ft with 4 SPF. Rock data and fluid data shown in the Table 4, Table 6 and stress profiles from the FracHite log were used to run the model. The frac job consisted of 30,000 gal 35 lb borate crosslinked gel and 90,000 lb of proppant as shown in the earlier example. From Figure 12 it can be seen that the fracture height at the end of the treatment is approximately 380 ft and the frac length is 375 ft. The fracture modeling therefore, supports the hypothesis that the Brushy Canyon zone shows tendency to frac vertically.

Other factors that have shown better qualitative well productivity is higher breaker loading and use of delayed breakers. It is also felt that onsite quality assurance programs have generally helped in overall productivity improvement and reduced job failure rates.

SUMMARY OF FINDINGS

1. Most Delaware wells need to be fractured to be economical. They exhibit a tendency towards excessive fracture height growth which can be controlled by using cluster perforating the approximate center porosity as opposed to blanket perforating the entire interval. This method also seems to reduce water production and post frac proppant flowback problem. Proppant flowback can be further helped by tailing in with curable resin coated sand. The formation is sensitive to completion fluid formulation, therefore care should be taken in completion fluid design.

2. Well productivity can be enhanced by using gels with lower polymer loading and higher concentration of delayed breakers.

3. On-site quality assurance and forced closure along with post frac shorter shut-in times seem to help well productivity due possibly to reduced proppant conductivity impairment caused by the gel filtercake.

4. The use of borate crosslinked gels as frac fluid seems to produce best overall results.

5. "Pipeline" fracs produce excellent results in certain areas.

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Table 1
Delaware Field Data

Field	Perforations	Frac. Grad. psi/ft	Fracture Information	Production
Avalon	3015' - 3150' 3800' - 4050'	0.71	20,000-60,000 gals X-Link 35# Borate 30,000-60,000# 20/40 Brady 10,000-32,000# 20/40 RCS @ 10 to 18 BPM, Avg Injection Rate	30 - 70 BOPD 30 - 75 BWPD
Burton Flats	4000 - 4260' 4450 - 4550' 5650 - 5750'	0.62	10,000-30,000 gals 35# X-Link Borate 15,000-40,000# 20/40 Brady Sand 6,000-15,000# 20/40 RCS @ 5 to 10 BPM Avg Injection rate	30 - 75 BOPD 50 - 300 BWPD 5 - 15 MCFPD
Catclaw Draw	5800' - 5900'	0.64	7,500-15,000 gals 30# X-Link Borate 15,000-30,000# 20/40 Brady Sand 7000-10000# 20/40 RCS @ 8 to 10 BPM Avg Injection rate	80 - 150 BOPD 150 - 300 BWPD 10 - 25 MCFPD
East Loving	6050' to 6200	0.49	10,000-40,000 gals 30-35# X-Link Borate 20,000-85,000# 20/40 Ottawa Sand 9,000-20,000# 20/40 RCS @ 10 to 35 BPM Avg Injection Rate (Some "Pipeline" Fracturing)	60 - 150 BOPD 70 - 300 BWPD
Hat Mesa	6750' - 6780' 7350' - 7500' 8200' - 8250'	0.69	10,000-40,000 gals 35# X-Link Borate 20,000-85,000# 20/40 RCS @ 5 - 10 BPM Avg Injection rate	100 - 150 BOPD 0 - 75 BWPD
Livingston Ridge	6600' - 6700' 7200' - 7350' 8150' - 8250' 8350' - 8450'	0.57	10,000-40,000 gals 30-40# X-Link Borate 15,000-60,000# 20/40 Ottawa Sand 10,000-30,000# 20/40 RCS @ 5 -15 BPM Avg Injection Rate	150 - 350 BOPD 200 - 350 BWPD 10 - 17.5 MCFPD
Lusk	6400' - 6475' 7380' - 7430'	0.64	10,000-20,000 gals 35# X-Link Borate 20,000-35,000# 20/40 Brady @ 5 - 6 BPM Avg Injection Rate	N/A
Parkway	4090' - 4115'	0.61	10,000-20,000 gals X-Link 35# Borate 15,000-25000# 20/40 Ottawa Sand 7000-12000# 20/40 RCS @ 7 to 15 BPM - Avg Injection rate	50 - 100 BOPD 30 - 70 BWPD 75 - 250 MCFPD
Sand Dunes (Poker Lake)	7300' - 7500' 7750' - 8000'	0.55	30,000-60,000 gals 35# X-Link Borate 25,000-40,000# 20/40 Ottawa Sand 8,000-20,000# 20/40 RCS @ 25 to 35 BPM , Avg Injection Rate (Some "Pipeline" Fracturing)	300 - 1000 BOPD 0 - 200 BWPD 100 - 500 MCFPD

Table 2
Analysis of the Study
Time Frame: Jan 1, 1988 to May 31, 1993

Item Studied	Number	Percentage	
Fields	9	-	
Operators	26	-	
Wells Treated	328	100.0%	
Wells Fractured	241	73.7%	
Borate Fracs	192	79.7%	*
Titanate Fracs	18	7.5%	*
Foam/Linear	31	12.9%	*
Forced Closed	106	44.0%	*

* Percentage with respect to wells fractured

Table 3
Average Fracture & Temperature Gradients

Zone	Frac Grad (PSI/FT)	Temp Grad Deg F/Ft	Avg. BHFP (PSI)	Avg. BHT (Deg F)
Cherry Canyon	0.61	0.77	3720	120
Upper Brushy Canyon	0.55	0.77	3960	129
Lower Brushy Canyon	0.53	0.77	4300	136

Table 4
Reservoir Properties Used in Computerized Design

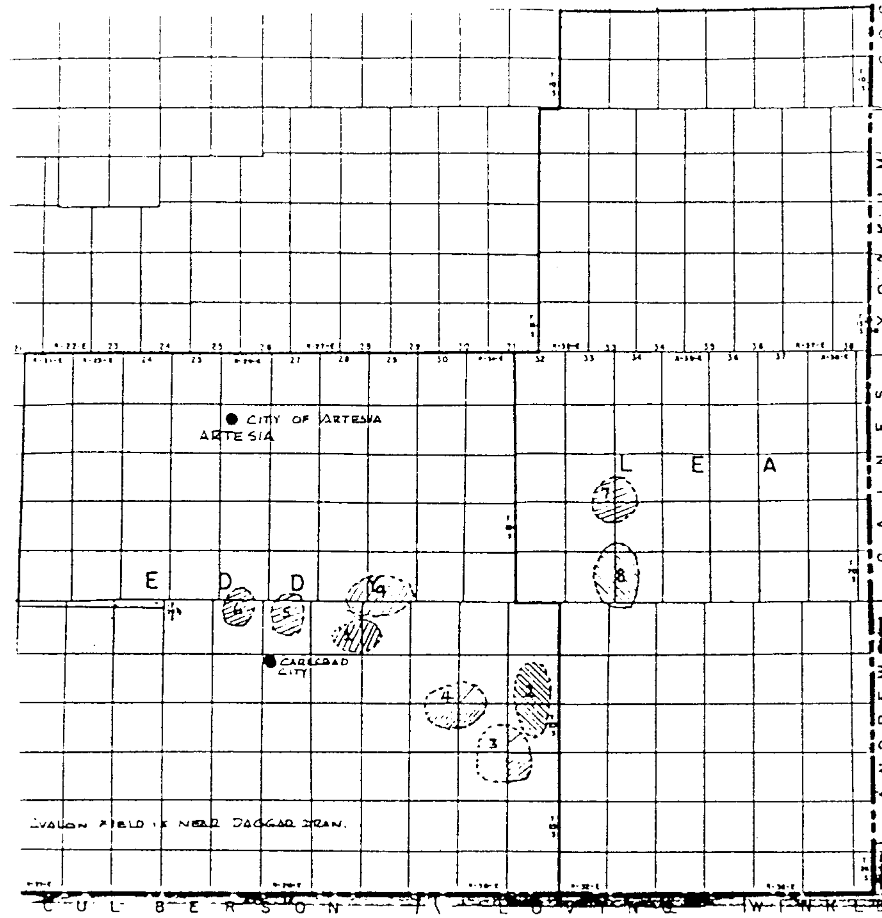
Property	Range	Average
Temperature Gradient	0.72 - 0.81 Deg F/100'	0.77 Deg F/100'
Formation Permeability	1.0 - 6.0 millidarcies	3.0 millidarcies
Formation Porosity	8.0 - 18%	12.0%
Reservoir Pressure	1500 - 2800 PSI	2400 PSI
Young's Modulus	4.0 - 5.6 x 10^6 PSI	5.0 x 10^6 PSI
Poisson's Ratio	0.2-0.25	0.23
Reservoir Fluid Viscosity	2.2 - 3.0 cp	2.8 cp
Reservoir Fluid Gravity	35 - 43 Deg API	38 Deg API
Avg Perm to Frac Fluid	-	1.8 millidarcies

Table 5
Mineral Content of the Delaware Formation

Mineral	Parkway	Burton Flats	Livingston Ridge
Quartz	81%	64 - 72%	65 - 85%
Feldspar	6%	8 - 14%	10 - 25%
Calcite	Trace	Trace	2 - 7%
Dolomite	Trace	3 - 11%	1 - 2%
Siderite	-	-	Trace
Pyrite	1%	1%	1%
Ankerite	-	-	1 - 2%
Anhydrite	-	1 - 5%	-
Total Clays	11%	6 - 15%	1 - 3%
15% HCl Solubility	6%	6%	8 - 13%
Acid Soluble Iron	0.6%	0.5 - 1%	0.6 - 1%
Clay Makeup			
Chlorite	76%	58%	93%
Illite	24%	42%	7%
Montmorillonite	-	-	Trace
Kaolinite	-	-	-

Table 6
Frac Fluid Properties @ 130 Degrees (F)
35 PPT Guar with Borate Crosslinker

Property	Avg. Value
Leak-Off Viscosity	1.0 cp
Spurt Loss	0.0 cc
N'	0.55
K'	0.09



Field Legend

1. Burton Flats
2. Livingston Ridge
3. Sand Dunes (Poker Lake)
4. East Loving
5. Daggar Draw
6. Catclaw Draw
7. Lusk
8. Hat Mesa
9. Parkway

Figure 1 - Map of Delaware Fields, Eddy and Lea Co., New Mexico

BRUSHY CANYON SCANNING ELECTRON MICROGRAPHS

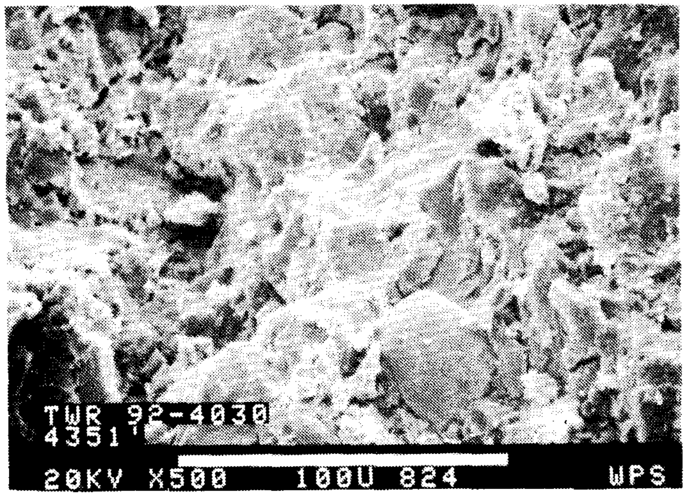


Figure 2 - Extensive coating clays obscure the grain outlines of most of the framework grains except the quartz grain at bottom-right. Illitic clays and mixed layer chlorite/smectite are coating most grain surfaces.

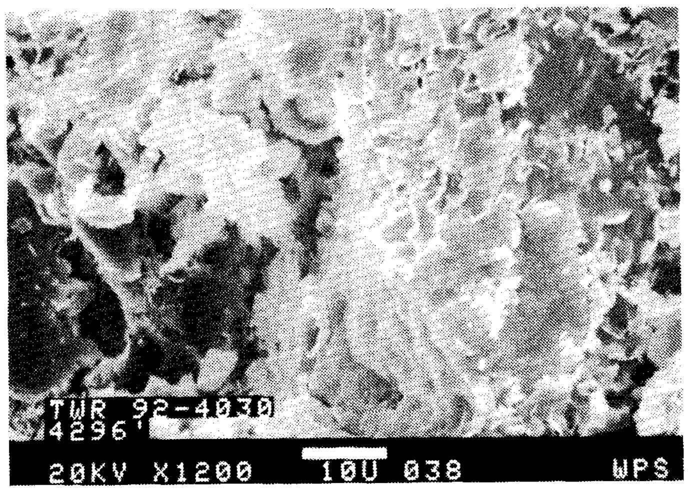


Figure 3 - Crenulated mixed-layer chlorite/smectite is seen at the right-center, coating a quartz framework grain. Illitic clays are also visible-at left-on a grain surface.

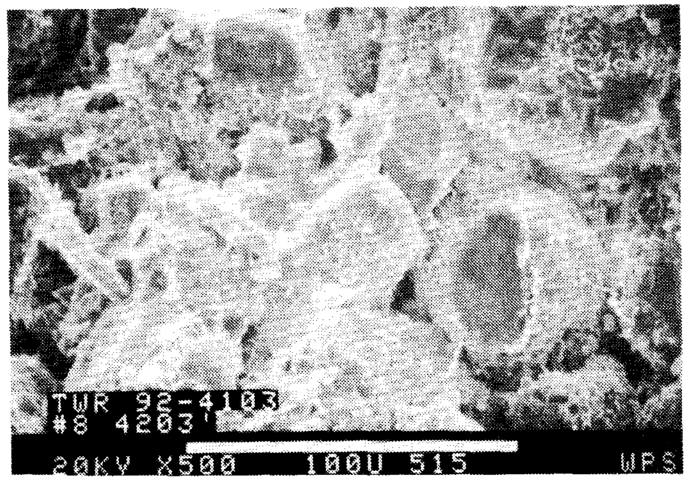


Figure 4 - Open intergranular pores are visible. Quartz grain contacts are observed where authigenic clays could not precipitate. Mixed-layer chlorite/smectite and mixed-layer illite/smectite are visible coating framework grains and lining the pore network.

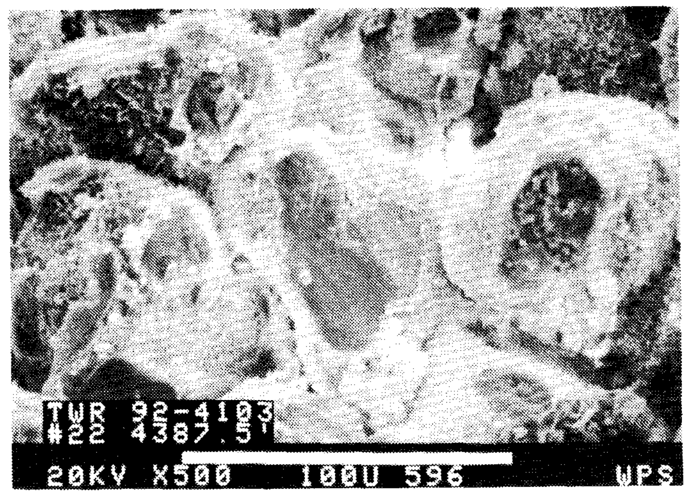


Figure 5 - This view shows quartz framework grains coated by mixed-layer chlorite/smectite and illite/smectite. The clay free areas are contacts with other framework grains where authigenic clay growth could not occur.

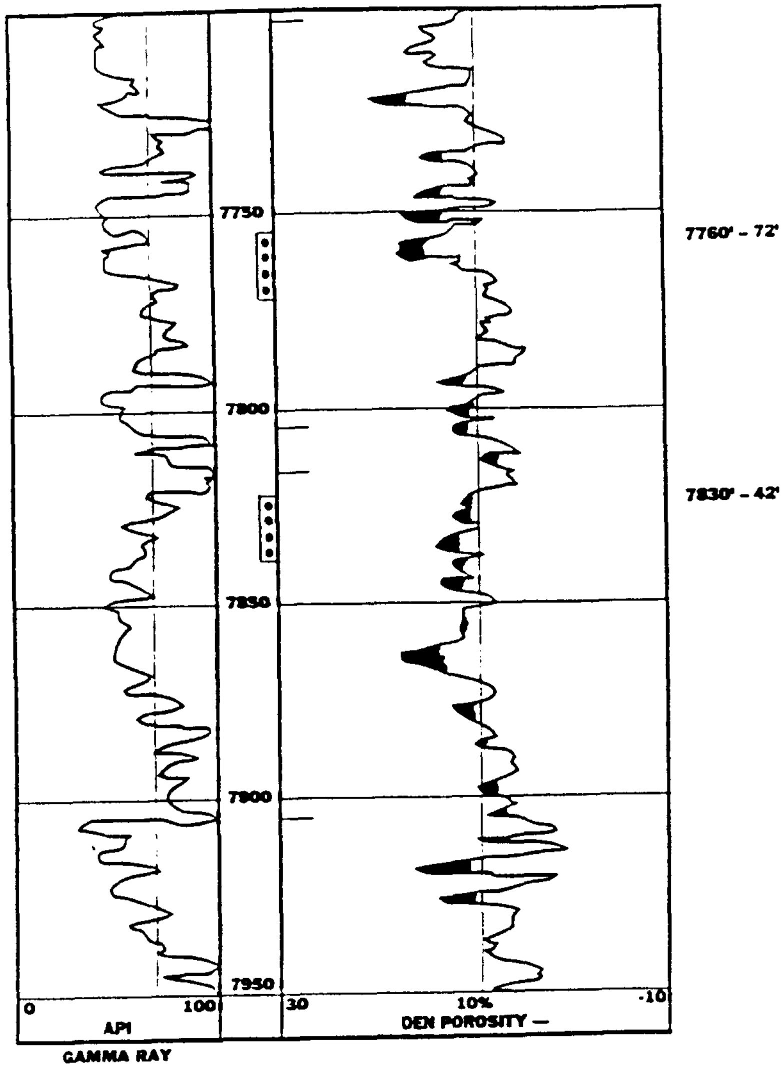


Figure 6 - Lower Brushy Canyon
spectral density dual spaced log

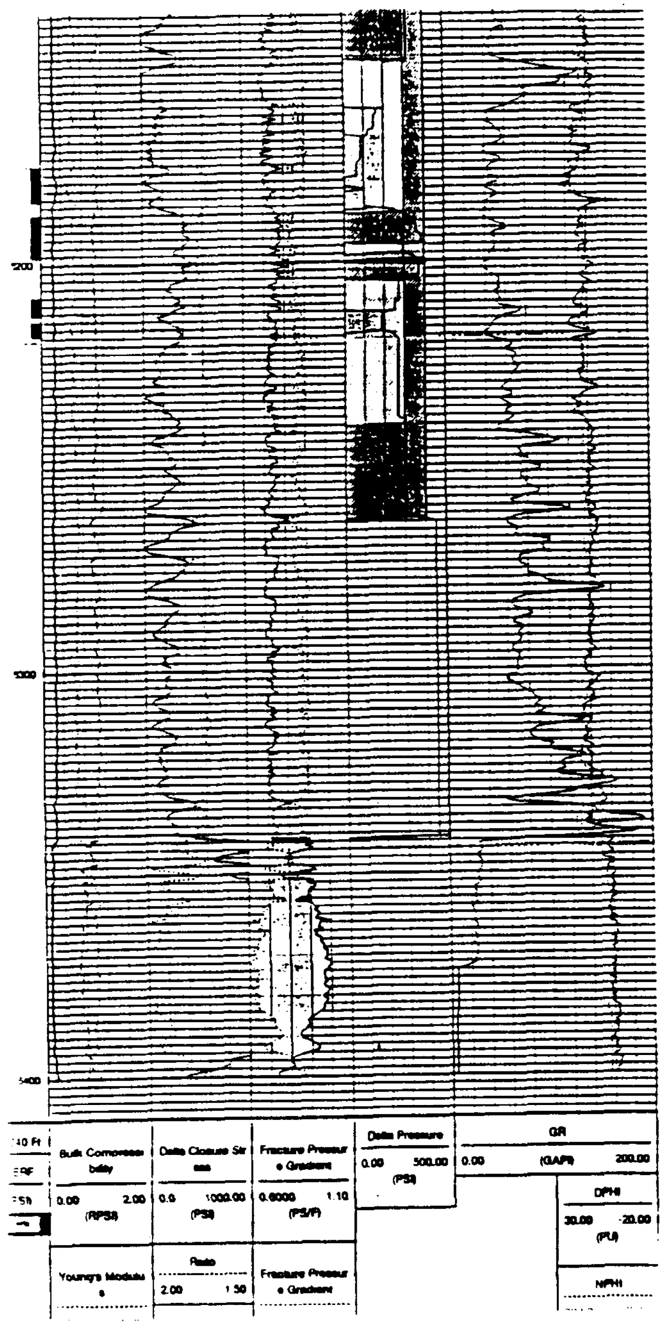


Figure 7 - E. Loving Field FracHite Log
Brushy Canyon suggested perfs
6, 190'-6,200' 4 SPF - 90° phase

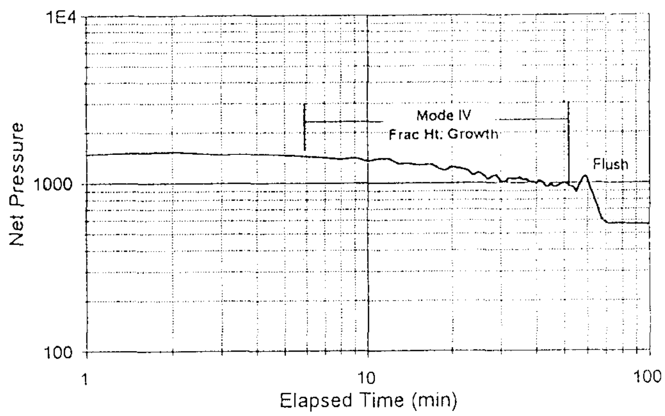


Figure 8 - Nolte plot E. Loving Field
Brushy Canyon, 6,175' to 6,200'

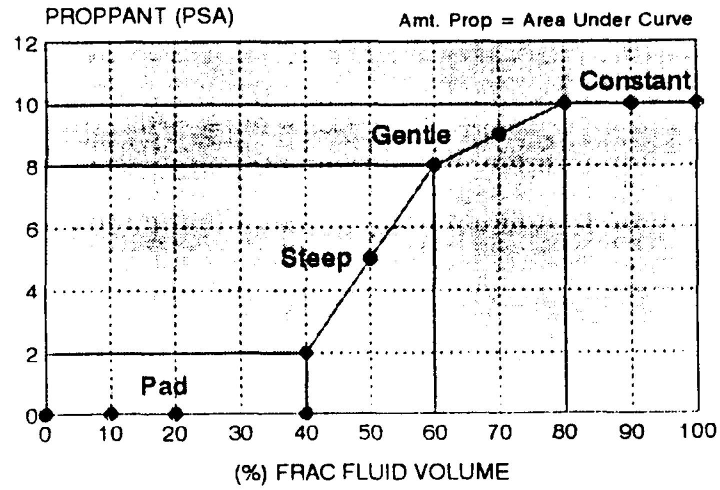


Figure 9 - Suggested proppant ramp

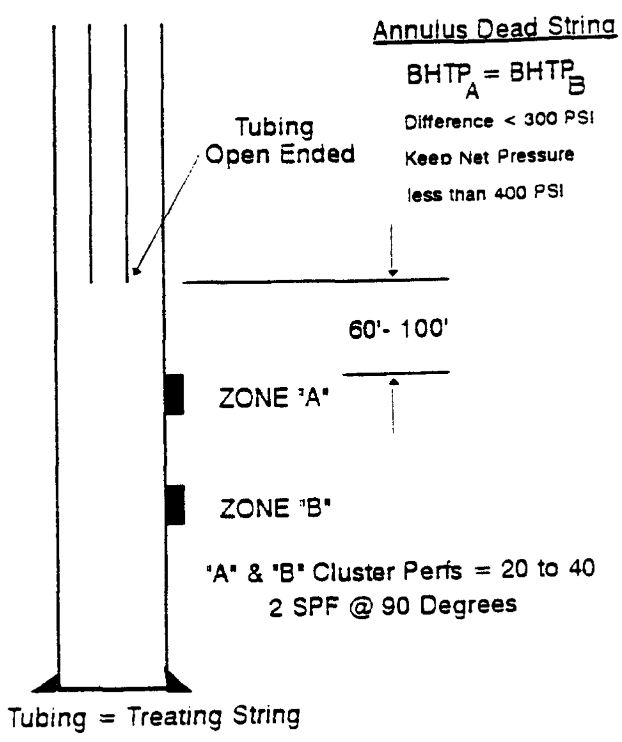


Figure 10 - Lower Brushy Canyon treating schematic

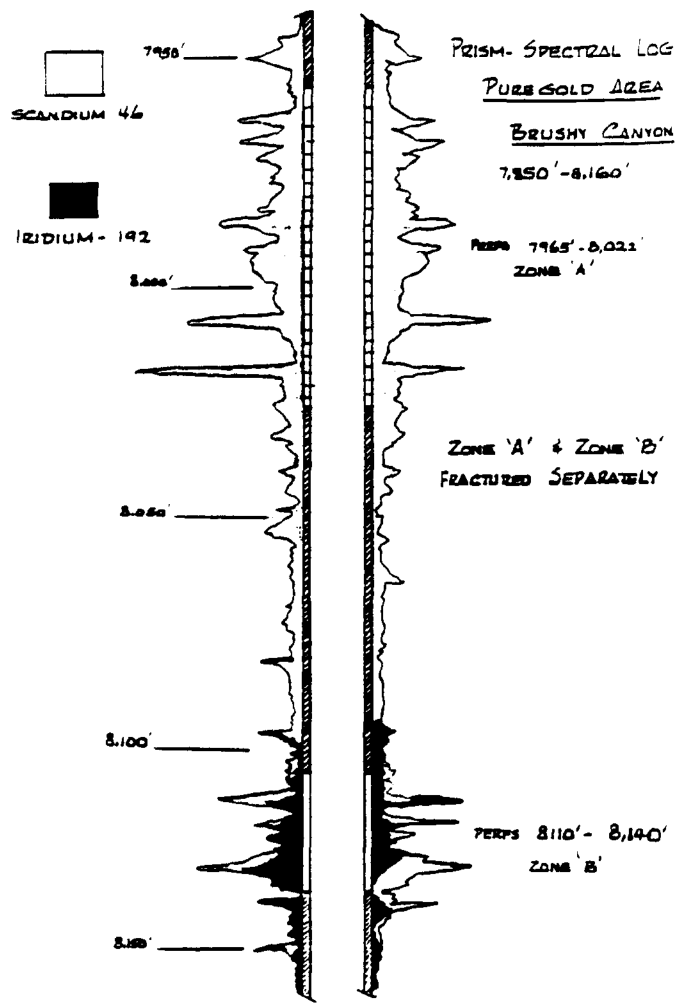


Figure 11 - Pure gold area prism - spectral log
(Brushy Canyon)

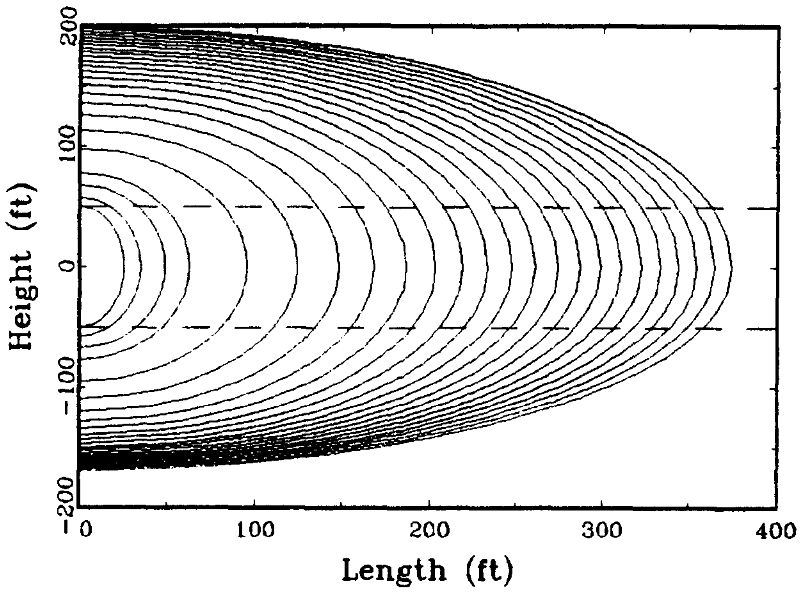


Figure 12 - Fracture profiles

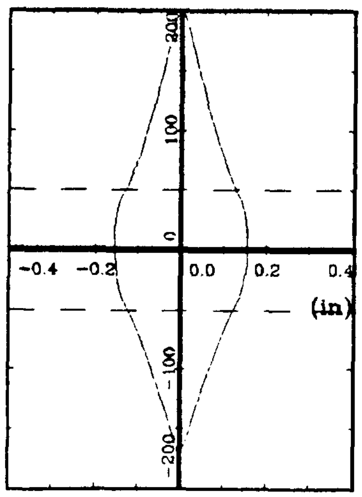


Figure 13 - Vert. width profile

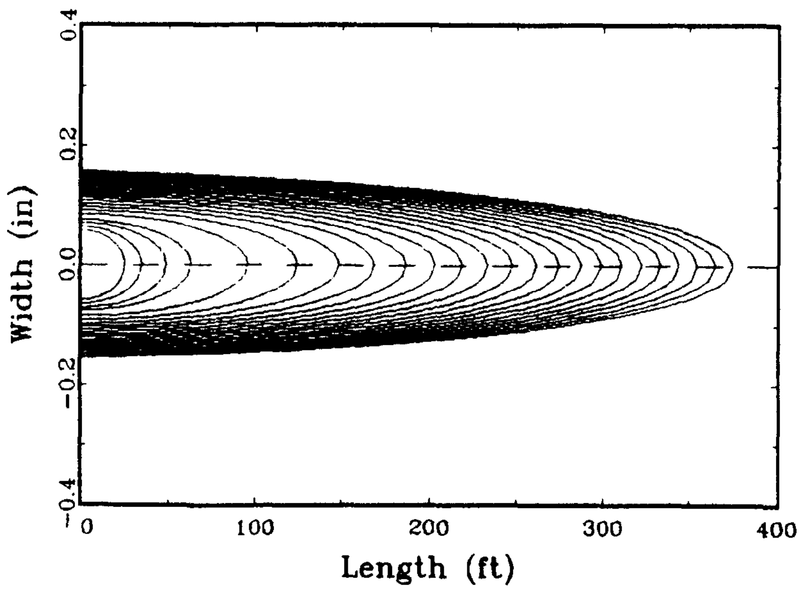


Figure 14 - Max. width profiles