EVALUATION OF ENCAPSULATED BREAKER USE IN WATER BASED FRACTURING FLUIDS IN WEST TEXAS AND SOUTHEAST NEW MEXICO

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ABSTRACT:

This paper discusses case histories of load recovery and production data from wells that were fracture treated with aqueous polymeric fracturing fluids utilizing encapsulated breaker in West Texas and Southeast New Mexico. The basic fracture treatment design of these wells and their actual load recovery and production history will be compared to results obtained from offset wells prior to the introduction of encapsulated breaker.

The case study will focus on 15 oil and gas wells in the permian basin that were hydraulically fracture treated with proppant placed using gelled-water-based fracturing fluids containing encapsulated breaker. The encapsulated breaker was used to maximize the clean up and minimize the damage caused by polymer in the proppant pack of the fracture. Recent studies have documented this damage to be more severe as the polymer concentrates with leakoff of the aqueous component of the fluid than previously suspected. This damage occurs during both the fracturing and fracture closure processes. Conventional breakers used at concentration levels needed to degrade this damage would result in fluid viscosity reduction when exposed to time and temperature during pumping operations. This viscosity reduction would result in job failure.

Proper fracturing treatment design combined with the correct utilization of the encapsulated breaker has been very successful in the aspects of fracture treatment operations and post treatment production results.

INTRODUCTION:

A measurement of the overall effectiveness of a propped hydraulic fracture treatment is provided by the dimensionless fracture conductivity expression, C_{FD}. It provides a link between the fracture and the reservoir in predicting the post-treatment well production. C_{FD} represents a ratio of flow capacities and can be thought of as a pressure drop. The higher the C_{FD} value, the lower the pressure drop inside the fracture. The result of a large C_{FD} value is a higher production rate and faster well cleanup.

$$C_{FD} = \frac{k_f w}{k x_f} \quad (.1)$$

where:

- k_f = in-situ fracture permeability, md
- w = effective propped fracture width, ft
- k = formation permeability, md
- x_f = effective propped half-length, ft

In order to more effectively optimize the production increase from a hydraulic fracture treatment, a C_{FD} value of at least 10 is needed. To achieve this, the fracture conductivity ($k_f w$) portion of the C_{FD} equation must be maximized. Since propped fracture widths in excess of 0.25 inches are extremely difficult to achieve, great emphasis must be placed to ensure that the fracture permeability remains as high as possible. Unfortunately, the in-situ fracture permeability is usually only a fraction of the original clean proppant permeability value.

FRACTURE CONDUCTIVITY REDUCTION:

For nearly twenty years, the proppant permeability numbers used in proppant fracture treatment designs have been significantly over-estimated. The factors which affect fracture permeability can be separated into two categories:

1. **Factors influencing conductivity under all conditions including the following:**

    - Reservoir Temperature
    - Closure Stress
    - Proppant Type
    - Proppant Strength
    - Grain Size And Distribution
    - Proppant Concentration
    - Embedment
    - Time At Stress And Temperature

    Past industry standards for the evaluation of proppant-pack permeability have utilized short-term testing methods using the equipment and procedures first described by Cooke. New studies have focused on long-term testing of proppant-pack permeabilities. These studies have shown proppant-pack permeabilities are dramatically reduced when exposed to long periods at temperature and stress. This behavior is primarily due to the rearrangement, embedment and packing of the proppant as it begins to crush. The long-term permeability values of many of the proppants tested in these studies have been documented. The previously reported short-term data values often exceed the newly documented long-term permeabilities by 50%. An example of this data is shown in Figure 1.

2. **The following factors influence conductivity based on the effects of fracturing fluids:**

- Gelling Agent Type
- Crosslinker Type
- Amount Of Fracturing Fluid Pumped
- Breaker Type And Concentration
- Proppant Concentration

Further studies have been performed to examine the effects of fracturing fluids on the proppant pack. Their findings have shown that the permeability of proppant packs may also be significantly impaired by the gelling agent used to viscosify the water-base fracturing fluid. Early data showed that different polymers and crosslinker types introduced varying levels of damage. More recent studies have shown that a larger degree of damage may result from the polymer becoming concentrated inside the fracture proppant pack.

The polymers used to create the gelled fracturing fluids are far too large to leak off into the rock matrix of most low permeability reservoir rocks. Initially the polymers are deposited on the fracture faces as a gelled filter cake. As fluid leakoff continues, the polymer concentration within the fracture steadily increases. Ultimately, during the closure process, all of the polymer used to create the fracturing fluid is concentrated and is left to fill the pore spaces of the proppant pack. The phenomenon of polymeric gelling agents becoming concentrated within the pore volume of the proppant pack was first introduced by Cooke. Assuming that all the polymer remains within the proppant pack, post-closure polymer concentration factors may be calculated using the following equation:

$$P' = \frac{\rho_s}{c_s} \frac{(1 - \phi/100)}{(\phi/100)} \qquad (.2)$$

where:

- P' = polymer concentration factor, dimensionless
- ρ_s = proppant absolute density, lbm/gal
- c_s = average proppant concentration, ppa, lbm added/gal fluid
- ϕ = proppant porosity

The final polymer concentration can be determined by multiplying the initial surface polymer concentration of the fracturing fluid by the calculated polymer concentration factor. Figure 2 shows the polymer concentration factor as a function of average proppant concentration for a proppant pack porosity of 35%. The graph indicates that polymer concentrations at the end of most fracture treatments may easily approach 400 to 500 lbm/1000 gal, and may often exceed 1000 lbm/1000 gal. Polymer concentrations of this magnitude are difficult to displace and will result in reduced fracture permeability as shown in Figure 3. This fracture permeability reduction will not be as severe if the polymers are thoroughly broken.

FRACTURE CONDUCTIVITY RETENTION:

Effects Of Breaker:

Reducing the fracturing fluid to a low viscous state was long thought to be sufficient to flow back the fracturing fluid and minimize the proppant-pack permeability damage. Recent studies have proven that this is not the case and that the conventional breaker designs used in the past are not sufficient to degrade the polymer and reduce the proppant pack permeability damage.

Conventional breaker designs used in the past were designed to work on the initial surface polymer loading and not the ultra high polymer concentrations inside the fracture. A much higher breaker concentration is needed to effectively degrade the concentrated polymer.

Thompson, et al., showed that the concentration of standard oxidative breakers must be significantly increased over traditional loading levels to improve the retained proppant permeability. This is exhibited in Figure 4. The amount of damage reduced is directly related to the amount of breaker added, regardless of the fracturing fluid type. The effects of fluid type remained consistent with earlier studies even with the addition of breaker. Linear fluids are less damaging than crosslinked fluids and borate crosslinkers are less damaging than metallic crosslinkers. The difference between guar and HPG base fluids are almost indistinguishable.

Unfortunately, the ammonium persulfate breaker concentrations required to effectively remove the polymer damage cannot be used (in its conventional form) without causing fluid viscosity to decline too rapidly during pumping.

Encapsulated Breakers:

In order to add breaker concentrations required to significantly reduce proppant pack permeability impairment, a delayed breaker system has been devised which will not compromise the fluid properties during treatment, yet will effectively degrade the concentrated polymer after the placement of the proppant is complete. The delayed breaker is created by encapsulating the oxidizing agent ammonium persulfate (APS) with a water resistant coating. The protective coating minimized exposure of the fracturing fluid to the breaker even though the breaker is added directly to the fluid. The coating allows high concentration of breaker to be pumped without causing premature viscosity degradation. As an an example of the effectiveness of the protective coating of the encapsulated breaker in a borate crosslinked guar fluid at 160° F, a delayed breaker concentration of 8 lb/1000 gal could be permitted whereas less than 1 lb/1000 gal conventional breaker concentration could be run. A minimum of 10% of the fluid viscosity would have to be maintained for effective proppant placement for this fluid. As shown is Figure 5, the corresponding retained permeability achieved was dramatically increased from less than 10% retained permeability at 0.5 lb APS/1000 gal to more than 40% retained permeability obtained for a breaker concentration of 8 lb APS/1000 gal.

Release of the breaker from the capsule occurs in two ways. After completion of the fracturing treatment, the hydraulic pressure dissipates (due to fluid leakoff) and the fracture closes, creating high point-to-point stresses on the proppant and encapsulated breaker. Faults occur in the coating that allow water to penetrate and solubilize the ammonium persulfate. The ammonium persulfate is then released into the concentrated fluid within the fracture. Additionally, some penetration of water occurs even with highly water resistant coatings. After sufficient exposure to water, encapsulated particles that may not be in a highly stressed state may have sufficient water penetration to release the breaker.

Due to the slight permeability of the protective coating, some small manufacturing imperfections in the coating and damage to the coating during pumping, low levels of active breaker may be released during the treatment. Testing has shown that the total amount of premature release is usually insignificant. After pumping the delayed breaker through surface equipment and then exposing it to a fluid at 150° F for three hours, the release was less that 5% by weight.

CASE HISTORY EVALUATION:

- **Case A: Two Brushy Canyon Formation Wells In Eddy County, New Mexico**
  - These two wells were fracture stimulated with proppant placed by a borate crosslinked refined guar fluid. The fracturing fluid in both wells utilized encapsulated breaker to maximize cleanup and effective fracture conductivity. Each of these case wells has a recently completed offset well in which the fluid did not contain encapsulated breaker. The two case study wells and their offsets have low bottom hole static temperatures of 110-115° F. Because of this low temperature, an amine breaker aid was added to the fluid system to function as a catalyst for the ammonium persulfate breaker. This breaker aid was used for both the encapsulated and the active forms of the ammonium persulfate oxidizing breaker.
  - Table 1 contains a fracture treatment summary of these wells. Figure 6 shows the initial production of each encapsulated breaker case well and its respective offset. The first case study well had an initial production of 1,137 barrels of oil per day (BOPD) while its offset produced at an initial rate of 848 BOPD. The second well utilizing encapsulated breaker produced at an initial rate of 65

BOPD, 180,000 cubic feet per day gas (Mscf/day) and 65 barrels of water per day (BWPD). Its offset is producing at a substantially lower initial rate of 50 BOPD, 50 Mscf/day and 50 BWPD.

  - A quantified measurement was not made on the initial load recovery but, the operator commented that the wells with the encapsulated breaker appeared to recover more load in a faster time period than their conventionally treated offsets.

- **Case B: Two Blinebry Formation Wells In S.E. New Mexico**
  - Like Case A, Case B focuses on two low temperature oil wells. These two offset wells were completed in the Blinebry formation using 16/30 Northern proppant placed by a borate crosslinked refined guar. They both contained an aggressive breaker schedule including encapsulated breaker, conventional ammonium persulfate breaker and a low temperature amine breaker aid. Table 2 contains a treatment summary for these jobs. A new offset Blinebry well is completed with a similar fracturing treatment with the exception that the fluid did not contain an aggressive breaker schedule.
  - The two encapsulated breaker wells in Case B are out performing the offset well as can be seen in Figure 7. The average initial production rate is 56 BOPD for the wells that used the aggressive breaker schedule compared to a 33 BOPD initial rate for the offset well which contained a conventional breaker schedule.
  - The operator indicated that the load recovery appeared to be faster and more complete from the encapsulated breaker case wells than from the offset well. No quantitative recovery measurements were made.

- **Case C: Five Sugg Ranch Field Canyon Formation Wells In West Texas**
  - In this case, five wells were hydraulically fracture stimulated using a delayed-titanate crosslinked fluid. This low-ph refined guar fluid was energized with 30% carbon dioxide by total volume. All five of these wells were completed in the Canyon formation. They are each located in different square mile sections respectively within the field.
  - Table 3 contains a fracture treatment summary for the wells in this case. The average post frac production decline results from these wells are shown in Figure 8 along with the average results of offset wells in the field. The offsets have received a variety of fracture treatments prior to the introduction of encapsulated breaker technology. From looking at these production statistics, it becomes apparent that the new system using the aggressive breaker schedule and the CO_2, is showing substantial improvement over previous systems. After 120 days, the case wells were producing at an average rate of 144 BOPD compared to an average of 106 BOPD from the other wells in the field over the same post frac time period. This reflects a net production increase of 36% per day per well yielded by the new wells.
  - The wells in this field using the previous fracturing treatment systems, including energized cases, traditionally have load recoveries of 25-35%. The average load

recovery for the five wells using the energized system with the encapsulated breaker is 45-65%. This additional load recovery should help improve long term production results from these wells. The reservoir pressure in this field has been somewhat depleted over time making this increased load recovery even more impressive.

- **Case D: One Canyon Formation Well Near Eldorado, Texas**
  - Two offset wells were recently completed in the same zone of the canyon formation. Both wells received the same size fracturing treatment which is summarized in Table 4. Encapsulated breaker was used on only one well.
  - The operator stated that the well which was treated using the encapsulated breaker cleaned up several times faster than the offset well. No quantitative measurements were conducted. Both wells flowed after the fracture treatments.
  - Initial gas production rate from the encapsulated breaker case well was 400 Mscf/day while the offset well which only received conventional breaker technology was 190 Mscf/day. These production results are shown in Figure 9.

- **Case E: Five Canyon Formation Wells In Sutton County, Texas**
  - In this case, a total of 32 wells have been completed in the canyon formation over a five section area. Table 5 contains a fracture stimulation treatment summary for these wells. The first 15 wells were completed and stimulated in the mid-nineteen seventies and received small low-conductivity fracture stimulation treatments. These treatments contained conventional breaker schedules and only 2.5 ppa maximum proppant concentration. The average fracture length from these treatments was 224 ft. The second phase of this case study was conducted in early 1989 on 12 wells within the same area. These wells received substantially larger treatments with conventional breaker technology but, much better fracture conductivity was realized. This higher fracture conductivity was created by increasing the maximum proppant concentration to 8 ppa over an increased fracture length of approximately 600 ft. SPE 20133 documents this initial case study in detail. As shown in Figure 10, this larger treatment with more conductivity resulted in an average 150 day cumulative production increase per well of more than 50 MMscf of gas. An additional benefit was realized from an average swab time reduction from 10-14 days with the old design to a 3 day average with the improved design.
  - As exhibited in Table 5, the 5 case study wells were recently fracture stimulated using the same treatment as the improved design except for the implementation of the new breaker technology, including the use of encapsulated breaker. Among the first advantages noticed from the addition of encapsulated breaker to the fluid was a swab time reduction from the 3 day average following the improved design to a less than one day. Most cases required no swabbing at all. Total load recovery has also been significantly improved on the wells where the encapsulated breaker has been used. In the past, frac fluid recovery rarely exceeded 25-30% where as an average of over 50% of the fracturing fluid has been recovered from

the case study wells. The 5 case wells that utilized the encapsulated breaker had an initial gas production production average of 2.046 MMscf/day per well. This is significantly more than the 1.365 MMscf/day initial per well production average from the 12 wells that did not receive the new aggressive breaker technology. Figure 10 shows the cumulative production results from these wells. The 5 case wells have an average per well cumulative production of 153.4 MMscf after 5 months while the conventional breaker treatments yielded an average of 120 MMscf over the same period. This 33.3 MMscf is a 28% increase in production for this time period. This case study is documented in substantially more detail in SPE 21497.

CONCLUSIONS:

1. Production from the wells that were fracture stimulated using fluids containing very high concentrations of breaker is substantially higher than their offsets which used conventional breaker concentrations. These results support laboratory conclusions that residue from polymeric fracturing fluids can significantly reduce well performance if proper breaker designs are not applied.
2. Extremely high breaker concentrations can be added to conventional fracturing fluids by using encapsulated breakers.
3. Wells using a high breaker concentration, due to the encapsulated breaker, show improved clean-up characteristics and increased load recovery.
4. The improved proppant pack permeability due to the higher breaker concentrations results in substantially higher initial production.
5. The improved clean-up and initial production results obtained by using higher breaker concentrations were realized in oil producing reservoirs as well as the gas producers.
6. The lower reservoir temperature (less than 140° F) cases using the encapsulated breaker, in combination with conventional breaker and the amine breaker aid have realized improved clean-up and higher initial production than their conventionally treated offsets.

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- Marathon Oil

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Table 1
Treatment Summary for Case A

FIRST BRUSHY CANYON WELL WITH ENCAPSULATED BREAKER		OFFSET WELL COMMENTS
DATA	DATA VALUE	
Proppant Type:	16/30 Northern White Sand	Similar Treatment With Conventional Breaker
Proppant Amount:	31,000 lbs.	
Maximum Proppant Concentration:	8 ppa	
Fluid Type:	35 lbs./mgal. Borate Refined Guar	
Fluid Amount:	13,000 gal.	
Average APS Concentration:	10.5 lbs./mgal. + Amine Breaker Aid	4 lbs./mgal. + Amine Breaker Aid
Bottom Hole Temperature:	115° F	

SECOND BRUSHY CANYON WELL WITH ENCAPSULATED BREAKER		OFFSET WELL COMMENTS
DATA	DATA VALUE	
Proppant Type:	20/40 Northern White Sand	Similar Treatment With Conventional Breaker
Proppant Amount:	10,000 lbs.	30,000 lbs.
Maximum Proppant Concentration:	12 ppa	
Fluid Type:	35 lbs./mgal. Borate Refined Guar	
Fluid Amount:	4,100 gal.	
Average APS Concentration:	9 lbs./mgal. + Amine Breaker Aid	4 lbs./mgal. + Amine Breaker Aid
Bottom Hole Temperature:	110° F	

Table 2
Treatment Summary for Case B

2 BLINEBRY WELL AVERAGE WITH ENCAPSULATED BREAKER		OFFSET WELL COMMENTS
DATA	DATA VALUE	
Proppant Type:	16/30 Northern White Sand	Similar Treatment With Conventional Breaker
Proppant Amount:	59,500 lbs.	
Maximum Proppant Concentration:	5 ppa	
Fluid Type:	30 lbs./mgal. Borate Refined Guar	
Fluid Amount:	39,000 gal.	
Average APS Concentration:	7 lbs./mgal. + Amine Breaker Aid	
Bottom Hole Temperature:	115° F	

Table 3
Treatment Summary for Case C

5 CANYON WELLS IN SUGG RANCH AVERAGE WITH ENCAPSULATED BREAKER		OFFSET WELL COMMENTS
DATA	DATA VALUE	
Proppant Type:	20/40 Northern White Sand	Various Systems With Conventional Breaker
Proppant Amount:	168,500 lbs.	
Maximum Proppant Concentration:	6 ppa	
Fluid Type:	30 lbs./mgal. LPH Titanate Refined Guar + 30% CO_2	
Fluid Amount:	76,600 gal.	
Average APS Concentration:	8 lbs./mgal.	
Bottom Hole Temperature:	160° F	

Table 4
Treatment Summary for Case D

ELDORADO, TEXAS CANYON WELL WITH ENCAPSULATED BREAKER		OFFSET WELL COMMENTS
DATA	DATA VALUE	
Proppant Type:	20/40 Northern White Sand	Various Systems With Conventional Breaker
Proppant Amount:	103,000 lbs.	
Maximum Proppant Concentration:	7 ppa	
Fluid Type:	35 lbs./mgal. Delayed Borate Refined Guar	
Fluid Amount:	30,000 gal.	
Average APS Concentration:	8.3 lbs./mgal.	
Bottom Hole Temperature:	150° F	

Table 5
Treatment Summary for Case E

5 CANYON WELLS IN SUTTON COUNTY, TX. WITH ENCAPSULATED BREAKER		15 OFFSET WELLS (OLD DESIGN)	12 OFFSET WELLS (IMPROVED DESIGN)
DATA	DATA VALUE	DATA VALUE	DATA VALUE
Proppant Type:	20/40 Northern White Sand	20/40 Northern White Sand	20/40 Northern White Sand
Proppant Amount:	500,000 lbs.	60,000 lbs.	500,000 lbs.
Maximum Proppant Concentration:	8 ppa	2.5 ppa	8 ppa
Fluid Type:	Borate Crosslinked Refined Guar	Various	Crosslinked Refined Guar
Fluid Amount:	120,000 gal.	60,000 gal.	120,000 gal.
Average APS Concentration:	6 lbs./mgal.	+/- 1 lbs./mgal.	+/- 1 lbs./mgal.
Bottom Hole Temperature:	160° F	160° F	160° F

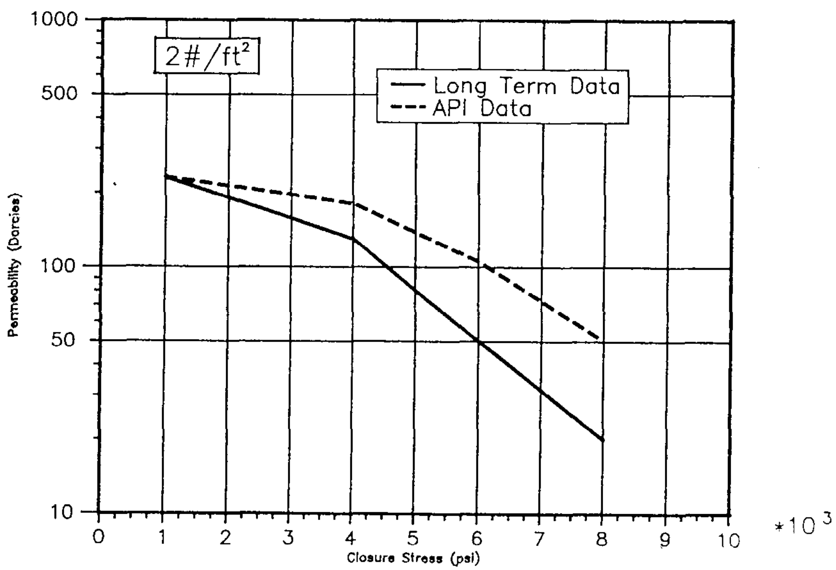

Figure 1 - Comparison of 20/40 NWS proppant permeability

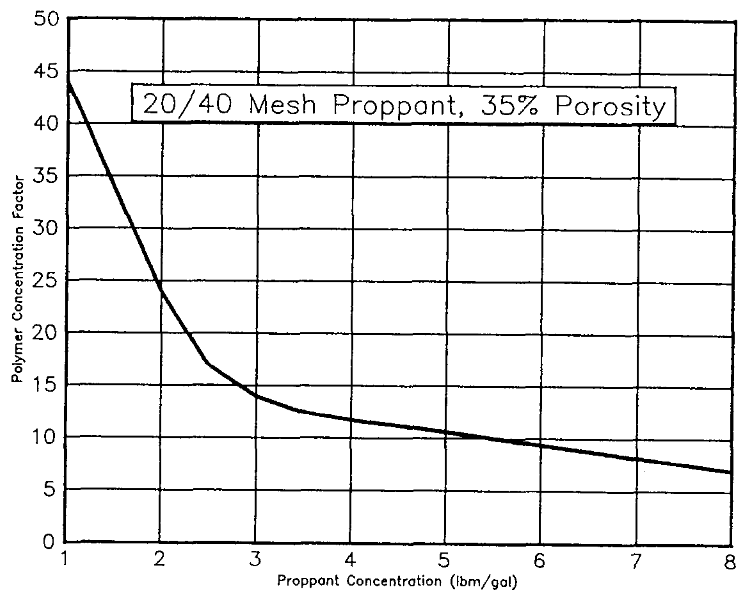

Figure 2 - Effect of proppant concentration

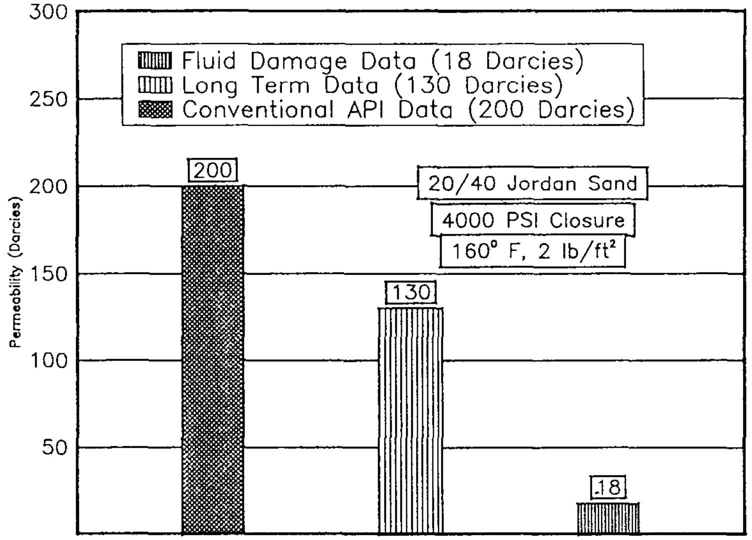

Figure 3 - Impact of long-term testing and fluid damage

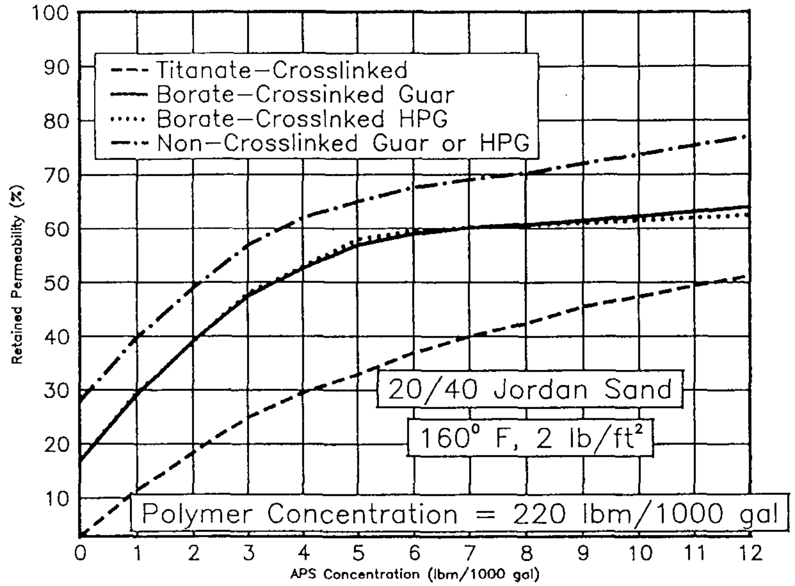

Figure 4 - Effect of breaker concentration for various fluids

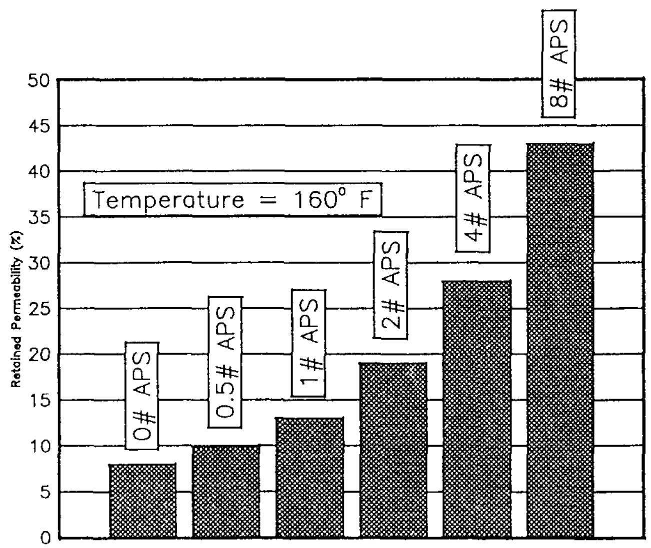

Figure 5 - Effect of breaker concentration on retained permeability

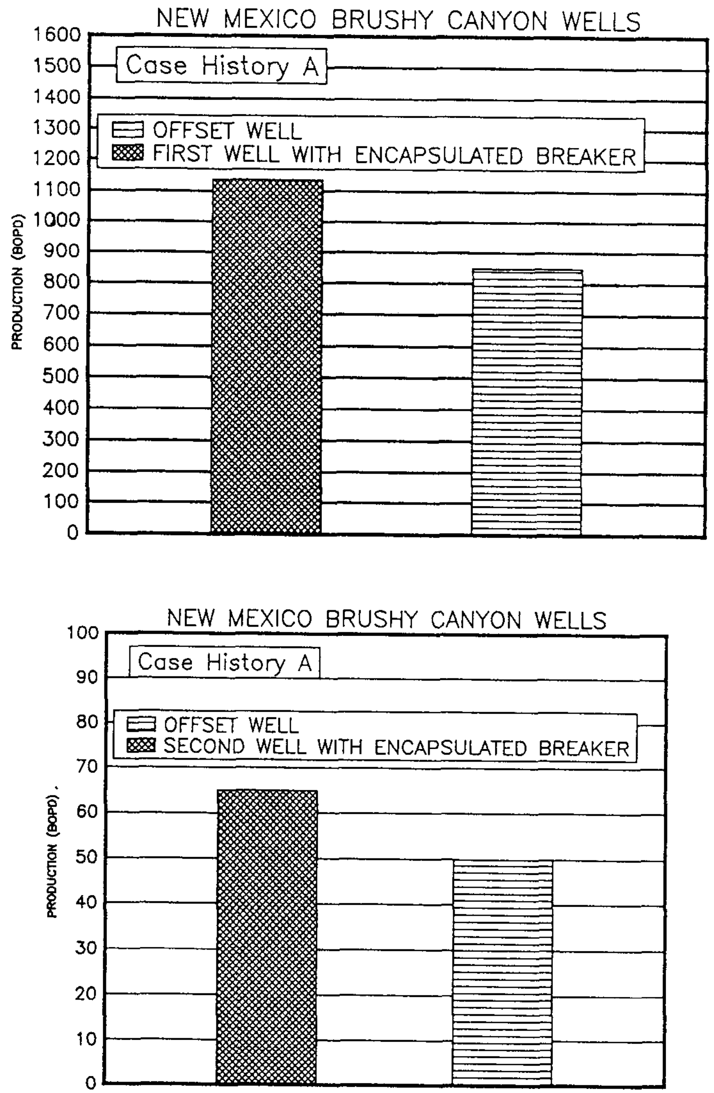

Figure 6 - Initial production comparison

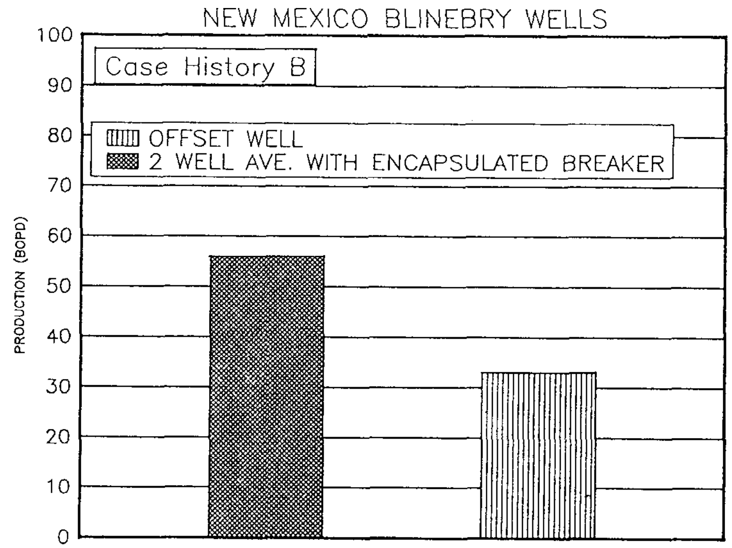

Figure 7 - Initial production comparison

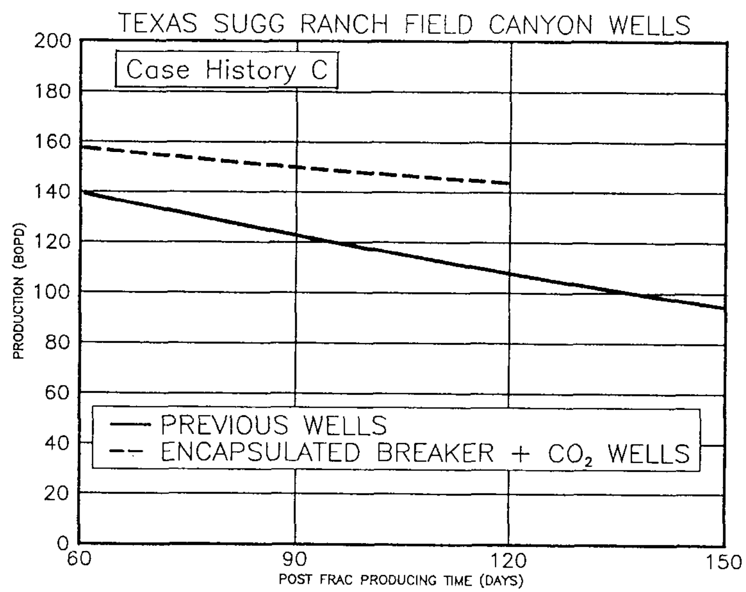

Figure 8 - Average production decline

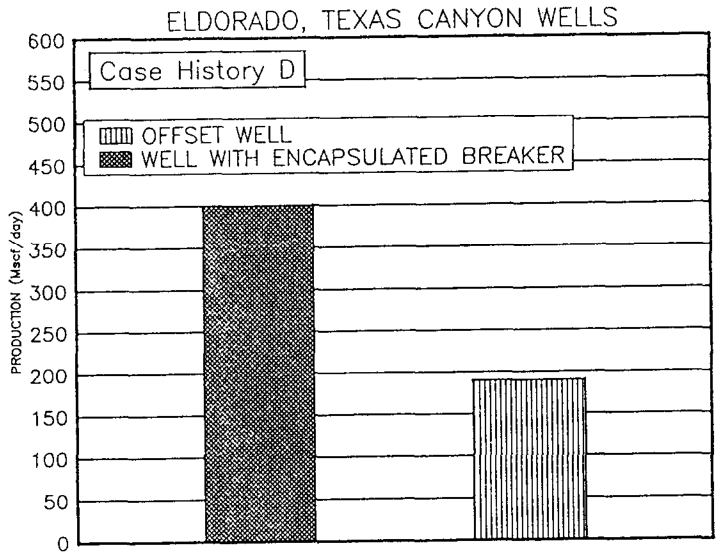

Figure 9 - Initial production comparison

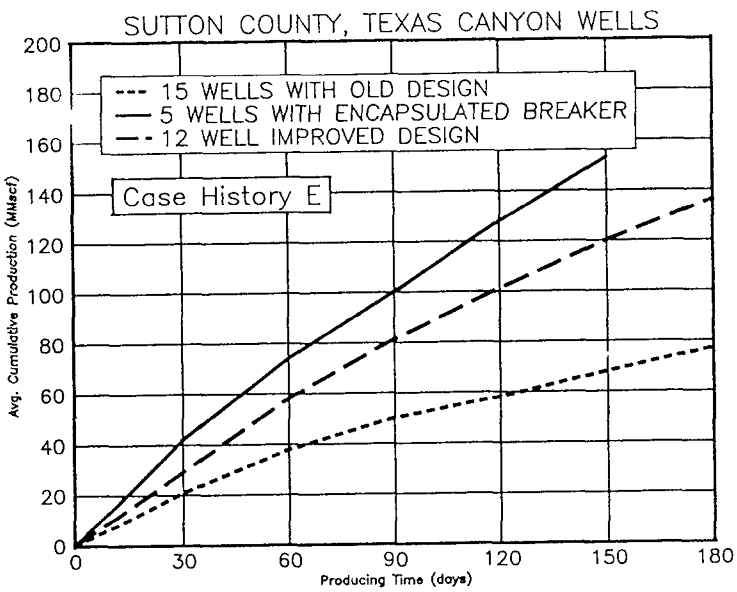

Figure 10 - Cumulative production comparison